128th Council Meeting

Friday, April 25, 2025

8:00 a.m.

Embassy Suites – Northwest Arkansas

Rogers, Arkansas

February 24, 2025

COPAS Board of Directors
Standing and Special Committee Chairpersons
Society Presidents
Council Representatives

Re: Notice of Spring 2025 Council Meeting

Dear COPAS Member:

The Spring 2025 Council of Petroleum Accountants Societies, Inc. (COPAS) meeting will be April 22-25, at the Embassy Suites – Northwest Arkansas Hotel, Spa, and Convention Center in Rogers, Arkansas. The hosts for this meeting are Arkansas and Tulsa.

The 128th meeting of the Council will be held at 8 a.m. on Friday, April 25, to conduct business as outlined on the attached agenda, as well as any other business that may be brought before the Council. The voting items on the agenda meet the 60-day notice requirement. There may be other items presented for vote that have not met the 60-day notice requirement and they will be managed according to the COPAS Bylaws.

The Council voting items are listed below with parenthetical indication of the vote required to approve that voting item.

1. Fall 2024 Council Meeting Minutes (majority)
2. January 2025 Special Council Meeting Minutes (majority)
3. Membership Assessment, effective August 1, 2025 (majority)
4. Approval of Publication Reopening for Updates Technical Corrections or Modernization (PRUTCOM) edits for publications listed in the agenda.

The Board of Directors will meet on Tuesday, April 22 from 8:00 a.m. to 5:00 p.m., and from 1:30 p.m. to 5:00 p.m. on Thursday, April 24. The Board of Directors meetings are open to all COPAS members, and you are encouraged to attend.

President-elect Kevin Launchbaugh will lead the COPAS Leadership Conference on Wednesday, April 23 beginning at 8:00 a.m.. A Leadership dinner for invited guests will be held on Tuesday, April 22 beginning at 6:00 p.m. A First Timers Mixer will be from 5:00 to 6:00 p.m. Wednesday, April 23.

The full Council agenda and handouts are included in this notice and are also available on the COPAS website. Committee agendas will be posted on the website when they are finalized. All times listed are Central time zone.

Please call Vanessa Galindo, COPAS Office Manager, if you have any questions or need assistance in registering for the meeting.

I look forward to seeing you in April.

Sincerely,

Kim Peyton

Kim Peyton, President

PO Box 21272 • Wichita, Kansas 67208-7272 • (303) 300-1131 • www.copas.org

Council of Petroleum Accountants Societies

Meeting

Agenda

128th Meeting
Council of Petroleum Accountants Societies, Inc. (COPAS)
Embassy Suites
Rogers, Arkansas

Council Meeting Agenda
8:00 a.m. Friday, April 25, 2025

Call to Order	Kim Peyton
Reading of COPAS Antitrust Policy	Scott Barrios
Society Welcome	Bryan Cox
Roll Call	Tom Batsche
Minutes of Council Meetings **Vote** – Approval of Fall 2024 Minutes (majority) **Vote** – Approval of January 22, 2025 Special Meeting Minutes (majority)	Tom Batsche
Financial Reports **Vote** – 2025 Membership Assessment Rates effective August 1, 2025 (majority)	Stephanie Schwindt
COPAS 2025 Goals and Objectives	Kim Peyton
COPAS Board of Directors Report	Carole Tear
Membership and Society Activity Report	Carole Tear
Bylaws Committee Report	Carole Tear
Leadership Conference Report	Kevin Launchbaugh
Research and Advisory Committee Report	Kim Peyton
Nominating Committee	Rebecca Paris
Executive Director Report	Tom Wierman
Editorial Committee Report	Tom Wierman

Audit Standing Committee Report	Cecil Sprague
Vote – Approval PRUTCOM Changes	
AG-9	
MFI-36	
Joint Interest Standing Committee Report	Vanessa Green
Vote – Approval PRUTCOM Changes	
AG-1, AG-12, AG-13	
MFI-14, MFI-18, MFI-23, MFI-27, MFI-31, MFI-35, MFI-37	
MFI-41, MFI-42, MFI-43, MFI-47, MFI-48, MFI-50	
Education Standing Committee Report	Jeff Wright
Financial Reporting Standing Committee Report	Ken Nollsch
Small Oil & Gas Companies Standing Committee	Howard Hong
Revenue Standing Committee Report	Robert Toudouze
APA® Program Report	Mike May
CEPS Control Panel Report	Dalin Error
First Timer Update	Robyn Tarnowski
Fall 2025 Council Meeting, COPAS Office	Tom Wierman
October 21-25, 2025 – Kansas City Marriott Country Club Plaza	
Kansas City, Missouri	
Spring 2026 Council Meeting, COPAS Office	Tom Wierman
To be Determined	
Fall 2026 Council Meeting, COPAS Office	Tom Wierman
To be Determined	

Future Meetings

Spring 2027	Houston
Fall 2027	COPAS Office

Other Business

Adjournment

Voting

Items

127th Meeting
COUNCIL OF PETROLEUM ACCOUNTANTS SOCIETIES, INC. (COPAS)

September 27, 2024

Westin Riverwalk Hotel
San Antonio, Texas

The 127th meeting of the Council of Petroleum Accountants Societies, Inc. (COPAS) was held on Friday, September 27, 2024, at the Westin Riverwalk Hotel in San Antonio, Texas.

Call to Order
President Craig Buck called the Council meeting to order at 8:00 am CT.

Welcome
Kirk Foreman of the San Antonio Society recognized Jeff and Misty Wright, Sandra Hoggard, Jessica Wagner, Dan Hodgson, David Garza, Kim Goodwin, and Carolyn Sczepanski as key contributors in making the conference a success.

COPAS Antitrust Statement
Tom Batsche read the COPAS Antitrust Statement.

Roll Call
Secretary Rebecca Paris called the roll of Council Members. Of the twenty-two (22) Participating Societies, 15 were present during roll call. The following societies did not have a representative present for the Council meeting: Appalachia, Ark-La-Tex, Corpus Christi, Kansas, New Orleans, Permian Basin, and Wichita Falls. A quorum was present.

Spring 2024 Council Meeting Minutes
The minutes of the 126th Council meeting held at the Hyatt Regency Jacksonville Riverfront in Jacksonville, Florida, were distributed in the 60-day notice and presented for approval.

Craig entertained a motion for approval of the minutes as presented. Houston moved and Tulsa seconded the motion. Craig asked if there was any discussion; hearing none he requested a vote by acclamation. The motion carried.

Financial Reports
A financial review was presented by Carole Tear.

Review of the five-year revenue trend indicated that membership assessments continue to trend up as we see recovery in membership of many societies. COVID had an adverse effect on our membership numbers in 2021. Membership numbers were fairly flat 2021-2023 and appeared to trend up in 2024. We saw a slight decrease in revenues from products and publications in 2024 as we continue to return to a level of sales prior to the bump from new documents released in 2022. We also saw a decrease in revenues from the APA® resulting from the 2023 bump created by the release of the APA® review course released in 2023. The large spike in Other Income in 2022 was due to the ERC funds received that year. 2023 Other income was related to the 2023 Spring meeting revenues, which are offset by related expenses.

As with previous years, the largest portion of our revenues was attributable to our publications and our member assessments. The year-over-year increase in member assessments was materially offset by the decrease in income related to the Spring 2023 meeting. The member assessment rate remained at $110 for 2024 but will increase to $115 in 2025.

Review of the five-year expense trend indicated that most expenses have stayed flat. An increase in marketing costs was related to website and marketing updates and rate increases. Depreciation decreased as assets became fully depreciated. Comparison of 2024 budget to actual costs indicated that costs year to date were tracking as expected.

Review of profit/loss actual to budget numbers for the last five years indicated that large projects had an impact on the ability to budget accurately. A large variance between the 2022 budget to actual was due to receipt of the ERC funds. For 2023, the variance was primarily due to the hosting of the Spring 2023 meeting, and unexpectedly high income from the APA® review course. 2024 year to date profit was significantly higher than budgeted profit because revenues are received early in the year and expenses fall more evenly throughout the year.

<u>COPAS 2024 Goals and Objectives</u>

Craig Buck, President of the COPAS Board of Directors, reviewed the six goals he covered at the Spring 2024 National Meeting.

1. Add 50 new members to COPAS.
   We have met and exceeded this goal by adding 64 new members this year!

2. Increase APA® Membership by 20%.
   While we have not increased our APA® membership by 20%, we have added six (6) new APAs®, and currently have forty (40) that have purchased the review course, twenty-three (23) of which bought the course this year.

3. Finalize partnership with Enverus to help with CEPS.
   We have not been able to finalize a partnership with Enverus to obtain data for CEPS yet, but Tom Wierman is still trying to work out some type of relationship

with them. We have signed a contract with JourneyApps and will begin a redesign the of the CEPS program in January!

4. Streamline the COPAS Publication Process to allow for document updates, technical corrections, and modernization.
   PRUTCOM was approved in the April meeting and the PRUTCOM team is currently working on documents. There should be several publication edits for approval in the Winter meeting.

5. Move common administrative tasks to the National Board to help provide relief to local Societies.
   Registration has been moved to the National Office; Tom W. provided further detail in his Executive Summary on how those efforts went. Additionally, we are looking at obtaining cloud storage soon so we can offer a document repository for committees and societies. The National Office and Board will also plan the Fall 2025 meeting.

6. Find a solution for members without any Societies.
   We have finalized a plan to start a remote society for all members who do not have a home but wish to remain active members of COPAS. This will not apply to any members that are within 70 miles of the city center of an existing society. We will also be sending out a FAQ sheet that goes into more detail about the remote society soon. Kevin provided more detail during his update membership update.

Janice Edmiston with the Houston Society asked if no Society steps forward to host the Spring Conference, for example, and the COPAS Office hosts, can a smaller society partner with COPAS Office? Craig responded that the COPAS Office can sign the contracts and make plans, and the society can help fill in the labor gaps as needed.

Lisa Collins with the Houston Society then asked about the suggestion earlier in the week for one virtual meeting and one in person meeting each year versus two in person meetings. Craig reminded the Council that at a previous Council meeting, the Board suggested this course of action, but Societies were not receptive to the idea. Craig noted the COPAS Board discussed a survey to gauge how members feel about that now before any actions are taken.

<u>COPAS Board of Directors Report</u>

Kevin Launchbaugh, Vice President, provided an update of the Board of Directors meetings since the last Council meeting in April.

The COPAS Board has met multiple times. During those meetings, the Board took the following actions:

- Approved the meeting minutes from July and August interim Board meetings.
- Approved the 2023 Financial Review Report.
- Implemented a Credit Card Convenience Fee effective July 1.
- COPAS has updated the membership renewal process with the following:
    - Membership renewal links were provided to societies on August 5.

    - Members have the option to pay by credit card or check for membership fees.
    - Society membership reports will be provided at the end of each month.
    - The societies' portion of the membership dues will be provided via ACH at the end of each month.
- We are working toward a membership report accessible by societies on the COPAS website.
- The 2025 CEPS surveys were sent out in September. If your company is a CEPS user, please ask your companies to fill out and return those surveys.
- Reviewed COPAS financials to date.
- Approved a contract with Journey Apps for a CEPS redesign.

Bylaws Committee Report
Kevin had no updates from the Bylaws Committee.

Membership and Society Activity Report
Kevin presented a summary of membership and society activity.

The COPAS Board sent out the society self-assessments in January. Based upon those responses, there were six (6) COPAS societies that were not in compliance with the requirements in the COPAS Bylaws regarding Participating Societies. The first was Acadiana which has since merged with the New Orleans society. Another was the Fort Worth Society which has since resolved the compliance issue.

Kevin noted that the 60-Day Council notice listed several voting items regarding society Bylaws compliance; one society is on the agenda for dissolution or termination from the Council (Appalachia) and three societies for suspension (Austin, Corpus Christi and New Mexico). Kevin noted for the voting representatives that suspended societies have a full year to get back into compliance with the requirements of a Participating Society.

The COPAS Board has developed an FAQ document regarding society dissolutions and suspensions as well as information on the COPAS Virtual Society. The FAQ document will be distributed by email.

Craig entertained a motion for dissolution of the Appalachia Society. Dallas moved and Houston seconded the motion. Craig asked if there was any discussion; hearing none the vote was done by roll call. A 2/3 majority of ten (10) societies was required. The motion carried 15-0-0.

Craig entertained a motion for suspension of the Austin Society. Oklahoma City moved and San Antonio seconded the motion. Craig asked if there was any discussion; hearing none the vote was done by roll call. A 2/3 majority of ten (10) societies was required. The motion carried 14-0-1 (Austin abstained).

Craig entertained a motion for suspension of the Corpus Christi Society. Arkansas moved and Houston seconded the motion. Craig asked if there was any discussion; hearing none the vote was done by roll call. A 2/3 majority of ten (10) societies was required. The motion carried 15-0-0.

Craig entertained a motion for suspension of the New Mexico Society. Houston moved and Tulsa seconded the motion. Craig asked if there was any discussion; hearing none the vote was done by roll call. A 2/3 majority of ten (10) societies was required. The motion carried 14-0-1 (New Mexico abstained).

Leadership Conference

Kim Peyton, President Elect, summarized the Leadership Conference.

She began by thanking the San Antonio society for hosting a great meeting! The Leadership Conference was held Tuesday, September 24, beginning at 1:00 pm CT. After the introduction by the sixty (60) attendees, Vanessa Galindo presented the rollout of the updated "Join Now" process for annual registration. She included a recap on how things are proceeding, some tips on how to use the website, and then answered some common questions.

Wade Hopper led a discussion on society bylaws, and instructed those present to be sure their society Bylaws are current and in line with COPAS Bylaws. There was good discussion resulting in some ideas for future updates that will be on the COPAS Board's agenda in months to come.

Wade then gave a presentation on Robert's Rules of Order. Discussion was lively and informative ending with an interactive demonstration of the Rules with Dan Triezenberg playing the role of COPAS President.

The last hour of the conference included a summation by Craig Buck of the progress that has been made based on suggestions and discussions during the COPAS Progression Panel meetings throughout 2023 and 2024.

1. The COPAS Office will plan and host the National Meetings beginning Fall 2025.
This change is in full force.

2. Membership registration administered by COPAS Office.
This change began in August of this year.

3. Bimonthly Meetings for CPE
This is scheduled to begin in November with a schedule to follow soon for next year.

4. Micro websites (exploring options) and Document Repository
This is in process.

To end the conference, Carole Tear held a discussion on FAQ related to the Virtual society, as well what suspension and dissolution means for a society.

The FAQs addressed the questions related to why the Virtual society was conceived, who is affected by it, when will the society be fully realized, and what the society will look like. To start, the creation of a Virtual society is in response to the need for a solution/option for societies that are having trouble staying in compliance with local and COPAS bylaws. It is also an option for COPAS members who are not close enough to an existing society to attend local meetings. The goal is to begin this Fall, and it will have all of the rights and follow all of the requirements of any other participating society. The Bylaws for the society are well in hand. The next step is to locate and nominate interested parties to serve on the Board of the new society.

The conference concluded with a Q&A session and suggestions for future Leadership conferences. The meeting concluded at 5:00 pm CT.

The Leadership Reception was held Tuesday evening and had 40 in attendance.

First Timers Social

Robyn Tarnowski, Chair of the COPAS Mentoring Advisory Committee, shared a recap of the Committee's activities.

COPAS Fall 2024 registration included thirty-nine (39) First Timers and twenty-two (22) COPAS Mentor volunteers.

A First Timer virtual welcome event was conducted on Wednesday, September 18. There was great participation with eighteen (18) First Timers and thirteen (13) COPAS Mentors participating in the call. The event consisted of four (4) breakout sessions, grouped by each registrant's focus area: Audit, 2 Joint Interest, Revenue/Financial Reporting/SMOG. This event provides an opportunity for participants to put a face to a name and has proven to ease the arrival at the meeting.

A First Timers Social was conducted Tuesday night and was well attended. There were eighteen (18) First Timers and twenty-one (21) COPAS Mentors present, in addition to eight (8) other COPAS members. There was no set agenda, just an opportunity to meet everyone in person and get to know each other better.

Research and Advisory

Dalin Error, Chair, noted that other than approving the Ring of Honor recipient, the Research and Advisory Committee has not met.

Executive Director's Report

Tom Wierman, COPAS Executive Director, presented the Executive Director's Report.

Tom W. gave an update on the membership renewal process. Largely the process has gone well but is experiencing some challenges. He noted those challenges and discussed how those items are being addressed. Tom noted that the August membership lists and payments were distributed. Tom answered a few questions from attendees regarding the membership process.

Tom is working on dates and locations for future COPAS meetings (beginning Spring 2026). He noted the Fall 2025 meeting will be held October 21 – 24 in Kansas City.

Tom noted the 2023 Financial Review team has completed their work. Tom thanked Bailee Crenshaw (Arkansas), Bryan Cox (Tulsa) and Nina Morgan (Mississippi) for their work.

Editorial Committee Report

Tom W. reminded the Council the Fall ACCOUNTS magazine was mailed on August 29. The next deadline will be November 1. He noted Committee and Society news reports were sparse in the last issue and asked for increased participation for the Winter issue.

Audit Breakout Session

Cecil Sprague, Chair of the Audit Committee, summarized the activities of the Audit Committee.

The Audit Standing Committee met separately immediately after the combined session. The meeting commenced at approximately 11:45 a.m. CT and concluded at 12:04 p.m. CT. Five (5) societies were present to vote, with about thirty (30) total attendees.

Robyn Tarnowski gave an update on the Emerging Issues sub-committee meeting held Wednesday, September 25, 2024.

Dalin Error gave the COPAS Board of Directors update.

The following items were approved:

1. Spring 2024 Meeting Minutes (Acclamation)
2. Summer 2024 Meeting Minutes (Acclamation)

New business topics were presented; the creation of a new Vendor Audit subcommittee, and a brief discussion on the status of getting projects moving and the next steps required in relation to the forthcoming PRUTCOM documents.

Joint Interest and Audit Combined Report

Cecil continued with a synopsis of the combined Joint Interest and Audit Committee meeting.

The Joint Interest and Audit Standing Committees held a joint meeting, Thursday, September 26. The meeting commenced at approximately 8:05 a.m. CT with approximately one hundred and thirteen (113) attendees.

Introductions were made and first timers were recognized. The antitrust statement was read.

Mike Cougevan gave an update on the status of the PRUTCOM documents being worked on and anticipated at least ten (10) documents would be finalized in the upcoming weeks with a possibility of twenty-two (22) documents being ready.

Vanessa Green then led an interactive polling discussion around MFI-35. These polling results will be reviewed and provided to the future MFI-35 document team.

Following Vanessa's presentation, a guest speaker from Vital Energy gave a presentation how AI is being leveraged with their field equipment at many of their well pads. It was a very detailed presentation on the use of AI and improvements that could be made when this technology is implemented fieldwide.

Joint Interest Committee Report

Patricia Ellington, Chair of the Joint Interest Committee, provided an update on the Joint Interest meeting.

The Joint Interest Standing Committee met after the combined committee meeting. There were twelve (12) societies present.

The Joint Interest Committee held a vote on the following items:

- Employee Benefit Percentage of 34%; 1% lower than 2023
- 2024 Winter Meeting minutes
- Vanessa Green as Joint Interest Chair

All items were approved unanimously.

Following the votes, the committee discussed approving a Joint Interest Vice Chair. The committee tabled a vote and requested the open position be discussed with the local societies.

Tom Batsche provided the Board of Directors report, and the committee adjourned at noon. The JI Committee thanked the San Antonio for a great COPAS meeting.

After her update, Patricia was presented with a plaque representing the gratitude of the Board for her tenure as Chair of the Joint Interest Committee.

Education, Financial Reporting and Small Oil and Gas Standing Committee Reports

Jeff Wright, Co-Chair of the Education Committee, reported for the combined Education, Financial Reporting, and Small Oil and Gas Standing Committee meetings.

The combined session met September 26 in San Antonio, Texas at 1:00 pm CDT. Jeff Wright welcomed the attendees and read the COPAS Antitrust Statement.

Carole Tear provided the COPAS Board of Directors report followed by an update by Kirk Foreman on the Model Form Accounting Procedure Side-by-Side project.

Carolyn Sczepanski, Education Committee Co-Chair, facilitated an ice breaker session prior to the first speaker, and Howard Hong, Small Oil & Gas Committee Chair, introduced the first speaker.

Jay White with Forvis Mazars presented on *Federal Taxation of Oil and Gas*. Forty-two (42) were in attendance from twenty-eight (28) companies and fifteen (15) societies. Two (2) attendees did not have a society affiliation. One hour of CPE was awarded for this session.

Following a break, Carolyn Sczepanski introduced Robert Park, an attorney with Uhl Fitzsimons. Robert's presentation was entitled *No Trespassing: What are Trespass Wells?* There were thirty-nine (39) attendees for this session from twenty-nine (29) companies and fourteen (14) societies. Two (2) attendees did not have a society affiliation. One hour of CPE was awarded.

Jeff announced to the attendees that the Education Committee has been tasked with organizing the new COPAS Lunch 'n Learn webinars. He solicited topics, and shared that the webinars will be free of charge and are expected to begin in November 2024. The presentations will likely be one-hour sessions commencing at 12:00 p.m. CST.

The meeting ended at 4:15 p.m. CST.

Revenue Standing Committee Report

Jeremy Norton, Revenue Committee Chair, provided a summary of the Revenue Committee Meetings.

The COPAS Revenue Standing Committee and the Revenue Sub Committees held meetings on Wednesday and Thursday, September 25 and 26, respectively. On Wednesday, Rebecca Paris provided the COPAS Board of Directors updates. The committee then began CPE presentations with topics including detailed legislative updates, a virtual presentation from the Office of Natural Resources Revenue on reporting and related override requirements for low pricing scenarios, a review of division of interest and escheat, carbon emissions reporting, the true cost of compliance, and the failure of the energy transition. Over the two-day period, there were eight (8) different presentations offering eight (8) hours of CPE. Both days were well attended with forty-three (43) in attendance on Wednesday and forty (40) on Thursday from thirteen (13) different societies.

Wednesday, after Rebecca's Board of Directors update, we began the first presentation led by Nate Wolf. Nate provided an update on state severance tax legislation for items that are pending and those that have passed.

The Office of Natural Resources Revenue (ONRR) gave a virtual presentation. They provided an overview of their current reporting override process that has caused delays in reporting. This helped attendees understand some changes ONRR has recently implemented to reduce the time it takes to get reports approved and submitted.

The Wednesday session concluded by approving Mia Downing from Martindale Consultants as the Revenue Committee Vice Chair. The committee is excited to have Mia join the leadership team!

Thursday was a full day of CPE. Donna King and the team from Energy Point Consulting provided us overview of the division of interest process that results in revenue decks for payment. They also covered the escheat process and some considerations to make when acquiring companies with suspense balances.

After they completed their panel, Lindsay Campbell with Validere gave a detailed presentation on carbon and methane emissions tracking and reporting. With all of the new regulations being implemented by various agencies around the globe, this is an evolving space for all companies to watch.

After a lunch break, Steve Bailey with Savvy Oil and Gas Consulting provided a review of the true cost of compliance. He helped attendees understand the hidden costs that should be considered when making investment decisions in agency leases to ensure the additional burden is part of our economic analysis.

Doug Sheridan provided an analysis of the energy transition and a review of its failure thus far. Attendees learned that solar is widely touted as a low-cost replacement for fossil fuels, but the costs that are being publicized are only the photovoltaic cells and do not include all the other cost associated with installing and operating a solar power grid.

Jeremy concluded the day with a legislative update on pending and passed legislation related to royalties.

Between the Spring meeting and this meeting, the Project Lead for the team working on AG-6, *Oil Accounting Manual* and AG-15, *Gas Accounting Manual* resigned. A new volunteer to lead the project was requested and an individual has responded with interest. The committee will be resetting these projects with a new project lead in the next few weeks and get them moving again.

Dan Hodgson, Midstream Subcommittee Chair, will be stepping down at the end of 2024. Dan was thanked for his service to the COPAS Revenue Committee. Dan has provided insight and perspective that members don't always receive and has provided many hours of training on midstream accounting. Volunteers are being recruited for this position.

Thank you to the Petroleum Accounting Society of San Antonio for hosting us this week!

After his update, Jeremy Norton and Dan Hodgson were presented with plaques commemorating their time as Chair of the Revenue Committee and Chair of the Midstream Subcommittee respectively.

APA® Program Report

Mike May, Chair of the APA® Board of Examiners, gave a report detailing the Board of Examiners meeting on Wednesday.

All members were present via teleconference or in person. The Board of Examiners (BOE) worked on updates to the manual and received a COPAS Board of Directors update from Tom Wierman, Executive Director. The BOE is very excited about the number of candidates signed up for the APA® review course.

An APA® certificate was awarded to Carole Tear who passed the exam in September.

CEPS Control Panel Report

Dalin Error updated the Council on several items related to the CEPS Control Panel.

Cumulative changes to tubular pricing in 2024 are represented by a reduction of 18.7%, driven by steel pricing as reported in the OCTG Situation Report. Adjustments to CEPS tubular pricing are made, upwards or downwards, when cumulative pricing changes are greater than or equal to 6%. The last change occurred in July 2024. Since then, the price generally has trended downwards, but not sufficiently to reach the +/-6% metric.

CEPS surveys have gone out to users. The CEPS panel anticipates meeting in November or early December to review survey results and determine 2025 HPMs.

Discussions with the developer JourneyApps for a rebuild of the CEPS application have been successful, and a contract will be signed with JourneyApps to begin development of the new version of the program. Discussions with Enverus regarding alternative pricing support for CEPS continue.

Industry Liaison Report

Kirk Foreman provided the Industry Liaison Report.

The Center for Energy Accounting (CEAS) at the University of North Texas, is excited have COPAS members attend the inaugural energy conference, *Energy Renaissance: Transformative Trends in Oil & Gas* on November 13 and 14 at the Westin Denver Downtown in Denver, Colorado. This will be an in-person only conference, and COPAS members get a 10% discount on the registration fee.

The John Jolly Memorial scholarship applications closed the first week of September and a recipient will be selected soon.

University of North Texas is moving forward with a Master in Energy Accounting degree program that will launch in the Fall of 2025.

Nothing to report on Desk and Derrick.

Ring of Honor

Craig began the introduction of the Ring of Honor recipient as a longtime Revenue Committee member, someone who served on multiple planning committees during which she planned fieldtrips to vendor locations for educational purposes, a longtime member of the Fort Worth society, former Director on the COPAS Board, active in the San Antonio society, COPAS President in 2008, and last but not least, well known for her distinctive hats. He invited the Council to show appreciation for the 2024 Ring of Honor recipient, Sandra Hoggard.

Eagle Award

Craig described the Eagle Award recipient as a current member of PASH, whom who served in multiple leadership roles in PASH and on multiple drafting teams, a former Joint Interest Chair, and currently serves on the COPAS Board of Directors. Tom Batsche was awarded the 2024 Eagle Award.

Nomination Committee Report
Dalin introduced the three nominees for the 2025 Board of Directors:
Kim Peyton, Mississippi Society
Stephanie Schwindt, Colorado Society
Lisa Collins, Houston Society

Craig entertained a motion to elect the three nominees to the Board of Directors as presented. Houston moved and Michigan seconded the motion. Craig asked if there was any discussion; hearing none he requested a vote by acclamation. The motion carried.

Craig took nominations from the floor for next year's Nominating Committee. Tulsa nominated Vanessa Green and Houston nominated Robyn Tarnowski.

Craig entertained a motion to elect the two nominees for the Nominating Committee as presented. Michigan moved and Arkansas seconded the motion. Craig asked if there was any discussion; hearing none he requested a vote by acclamation. The motion carried.

Recognition of Retiring Board of Directors
Craig Buck and Dalin Error were recognized for their contributions to the Board of Directors. The two have had a profound impact on the success of COPAS as an organization.

Future COPAS Meetings
Spring 2025 Council Meeting, hosted by the Tulsa and Arkansas Societies
    April 21-25, Embassy Suites
    Rogers, Arkansas

Fall 2025 Council Meeting, hosted by the COPAS Office
    October 21-24, Marriott Country Club Plaza
    Kansas City, Missouri

Future Meetings
Spring 2026   COPAS Office
Fall 2026   COPAS Office
Spring 2027   Houston Society (75th Anniversary)

Adjournment
Craig entertained a motion to adjourn. Oklahoma City moved and San Antonio seconded. The motion carried. The meeting was adjourned at 10:00 a.m. (CT).

Respectfully Submitted,

Rebecca Paris
COPAS Secretary

COUNCIL OF PETROLEUM ACCOUNTANTS SOCIETIES, INC. (COPAS)

GENERAL COUNCIL

January 22, 2025
Via Email

Societies Present and Voting:

Permian Basin – Evan Green
Kansas – Meghann Finlay
Oklahoma Tulsa – Bryan Cox
Houston – Kathy Johnston
California – Alma Gonzalez
New Orleans – Scott Barrios
Dallas – Lucas Vaughn
Rocky Mountain – Colby Rich
Michigan – Dan Triezenberg
Colorado – Stephanie Schwindt
Anchorage – Erin Ruebelmann
Arkansas – Bailee Crenshaw
San Antonio – Kirk Foreman
Oklahoma City – Kristin Rose
Mississippi – Quint Withers
Fort Worth – Jessica Morales

Executive Director, Tom Wierman, sent an email to all society presidents on behalf of COPAS President, Kim Peyton, on January 8, 2025, at 1:42 PM (CT):

Council Voting Representatives,

The Board recently updated the COPAS Bylaws to propose a new Virtual Society as well eliminate the Limited membership category. (Limited members will now be members of the Virtual Society). This is consistent with the discussions that took place in 2024 through the COPAS Progression Panel. With this in mind, we would like to call a special electronic meeting in accordance with the Bylaws section listed below to approve these revised Bylaws.

Attached for your review is a redline of the changes to the Bylaws as well as the clean copy. This meeting is only being called to approve the proposed Bylaws changes so that we continue to progress on what the board and other leadership have been working on to get the Virtual Society up and running in a timely manner.

This is the format we will be following to do this special electronic meeting.

In the event of an emergency or urgent Council voting matter only, a special electronic or telephonic meeting or an electronic virtual meeting shall be called by the President, by a majority of members of the Board of Directors, or by a majority of Council representatives. The notice of the meeting shall be given by the President, or by the Vice President if the President fails to issue such notice, at least ten (10) days prior to the date of the meeting giving the time and purpose of the meeting in reasonable detail with agenda items identified on which a vote is anticipated. Such meeting must be approved by at least two-thirds (2/3) of the Societies eligible to vote as of the date of the proposed meeting, via electronic means within five (5) business days following notice of such meeting. Business conducted at this meeting shall be limited to those items identified in the meeting agenda. Technology used must be commonly available to the voting representatives and allow open, immediate debate and discussion among the representatives in attendance.

Please respond to this e-mail in favor or opposed to this special electronic meeting by end of business Wednesday, 1/15/25, so we can see if we have the 2/3 majority needed to move forward with the meeting on 1/22/25. **Please include your mane and society when registering your vote.**

Assuming the 2/3 majority is recorded we would then hold an e-mail meeting on Wednesday, 1/22/25, for the approving the updated By-Laws. No other Council business will be handled during this meeting. We will call the meeting to order at 8:00 A.M. (CST) and leave the floor open for debate and discussion via e-mail to all Council voting representatives until 12:00 P.M. (CST). Barring any negating discussion, at 12:00 P.M. (CST) Kim Peyton will call for a Council vote to approve the changes to the By Laws as presented. The vote will be conducted via e-mail and will be left open from 12:00 P.M. to 1:00 P.M. (CST). The vote will be tabulated by the Board Secretary. The voting results will be sent to the Council upon completion.

If you have any questions, feel free to reach out to me or Tom Wierman to discuss. If you are not the voting representative from your society, please forward this email to the appropriate person.

__Vote:__
Sixteen of the eighteen COPAS societies responded by the deadline of January 15, 2025. A quorum was present. The vote was 16-0-0 in favor of holding a special electronic meeting to approve the updated Bylaws that include the proposed new Virtual Society as well as the elimination of the Limited membership category, as the Limited members will become part of the Virtual Society. Motion passed.

Kim Peyton called the special meeting to order on January 22, 2025, at 8:00 AM (CT). The purpose of the meeting is to address two voting items. Mississippi made the motion for 1) Approval of the revised COPAS Bylaws allowing a Virtual Society and eliminating the Limited Member category, and 2) Changing the name of the Petroleum Accountants Society of California to COPAS Virtual Society. New Orleans seconded the motion. With the motion and second, Kim opened the floor for comments via e-mail, indicating that the comment period would remain open until 12:00 PM (CT). Seeing no discussion, at 12:00 PM (CT), Kim opened the meeting to approve the proposed Bylaws changes to allow for the Virtual Society and eliminating the Limited Member category, as well as changing the name of the Petroleum Accountants Society of California to COPAS Virtual Society. She stated the vote would remain open until 1:00 PM (CT).

<u>Vote:</u>
Fourteen of the eighteen COPAS societies responded by the deadline of 1:00 PM (CT) on January 22, 2025. A quorum was present. The vote was 13-0-1 in favor of approving the proposed Bylaws changes to allow for the Virtual Society and eliminating the Limited Member category, as well as changing the name of the Petroleum Accountants Society of California to COPAS Virtual Society. Motion passed.

Respectfully Submitted,

Tom Batsche
COPAS Secretary

Council of Petroleum Accountants Societies

Turning Energy Into Synergy

January 27, 2025

To: Tom Wierman, COPAS Executive Director

Subject: 2026 Recommended COPAS Member Assessments

The COPAS Board of Directors met on January 27, 2025, to establish the COPAS member assessment rates to be effective as of January 1, 2026.

In order to ensure a reasonable, predictable and independent adjustment to member assessment, the board followed the guidance adopted in the prior year when determining the proposed membership assessment rate. A published index, similar to one used in calculating the annual COPAS Audit Per Diem adjustment percentage (rounded to the nearest $5), was applied. The Board recommends the 2026 member assessments as follows: $120 for members of Participating Societies.

The 2026 member assessments will be a voting item at the Spring Council meeting. Please include this letter in the 60-day notice.

Respectfully,

Stephanie Schwindt

Stephanie Schwindt
COPAS Treasurer

Calculation of Adjustment as of 1/15/2025

Original Data Value

Series Id: CEU6054000030
Not Seasonally Adjusted
Series Title: Average weekly earnings of production and nonsupervisory employees, professional and technical services, not seasonally adjusted
Super Sector: Professional and business services
Industry: Professional and technical services
NAICS Code: 54
Data Type: AVERAGE WEEKLY EARNINGS OF PRODUCTION AND NONSUPERVISORY EMPLOYEES
Years: 2010 to 2024

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual	
2010	1036.41	1044.50	1045.30	1053.86	1110.81	1062.66	1068.71	1112.01	1078.65	1096.36	1088.49	1084.74	1073.43	
2011	1114.35	1084.32	1072.21	1086.25	1119.72	1080.23	1080.28	1076.51	1083.67	1135.04	1087.07	1084.73	1091.98	
2012	1113.32	1080.64	1079.93	1130.13	1088.08	1092.62	1126.94	1095.48	1147.42	1101.70	1103.60	1150.91	1109.29	
2013	1094.30	1118.16	1110.75	1117.08	1113.48	1164.02	1108.31	1118.64	1169.36	1126.63	1137.96	1176.86	1129.69	
2014	1129.94	1190.17	1195.24	1161.24	1158.84	1204.64	1154.55	1163.83	1164.59	1167.84	1222.32	1167.84	1173.49	
2015	1164.57	1215.77	1215.40	1180.84	1184.76	1183.74	1182.60	1239.11	1186.20	1202.93	1257.01	1200.69	1201.23	
2016	1201.32	1205.46	1201.48	1217.58	1260.59	1213.79	1220.54	1217.04	1223.43	1276.33	1226.68	1222.75	1223.94	
2017	1262.61	1228.27	1223.07	1284.32	1232.28	1237.83	1280.20	1237.51	1250.14	1302.37	1255.78	1255.32	1254.18	
2018	1245.93	1267.81	1261.57	1323.96	1272.53	1279.94	1325.58	1284.66	1344.90	1289.74	1291.98	1345.15	1294.63	
2019	1285.94	1294.46	1295.91	1308.53	1302.49	1360.24	1299.22	1321.32	1371.96	1322.39	1322.34	1372.33	1321.52	
2020	1312.79	1380.81	1373.80	1339.92	1349.06	1339.40	1343.16	1414.84	1355.19	1372.64	1436.63	1380.65	1366.57	Updated 1/18/2022
2021	1385.38	1383.56	1386.64	1409.65	1470.16	1408.17	1420.33	1483.13	1431.61	1462.13	1457.45	1462.16	1430.03	Updated 1/6/2023
2022	1530.41	1485.96	1478.62	1509.84	1554.34	1501.61	1508.42	1510.37	1525.25	1589.87	1530.08	1533.90	1521.56	Updated 1/11/2024
2023	1601.47	1561.06	1555.50	1648.27	1572.42	1569.66	1637.25	1575.26	1591.68	1656.92	1588.07	1595.76	1596.11	Updated 1/8/2025
2024	1590.30	1601.90	1609.58	1619.57	1614.34	1690.09	1632.90	1646.73	1717.19	1667.65	1672.19		1642.04	Updated 1/15/2025

2025 Calculation	
2023 Index	1596.11
2024 Index	1642.04
Change	45.93
Percentage Change	2.878%

Participating member	
2025 Rate:	$ 115.00
2026 Rate Calculation:	$ 118.31
2026 Rate rounded to nearest $5:	$ 120.00

*Limited member rates calculated for use as needed

https://beta.bls.gov/dataViewer/view/timeseries/CEU6054000030

2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	2022 Nov	2022 Dec
1530.41	1485.96	1478.62	1510.21	1554.72	1501.98	1509.14	1510.74	1525.99	1590.62	1530.81	1534.99

2023 Jan	2023 Feb	2023 Mar	2023 Apr	2023 May	2023 Jun	2023 Jul	2023 Aug	2023 Sep	2023 Oct	2023 Nov	2023 Dec
1601.47	1561.06	1555.5	1648.27	1572.42	1569.66	1637.25	1575.26	1591.68	1656.92	1588.07	1595.76

2024 Jan	2024 Feb	2024 Mar	2024 Apr	2024 May	2024 Jun	2024 Jul	2024 Aug	2024 Sep	2024 Oct
1590.3	1601.9	1609.58	1619.57	1614.34	1690.09	1632.9	1646.73	1717.19	1667.65

BLS Data Viewer

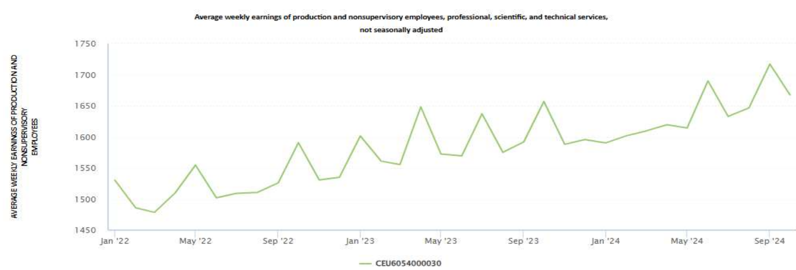
Permalink

Time Period: **Start Year:** 2022 **End Year:** 2024

Net Monthly Changes:
- ☐ 1-Month Net Change
- ☐ 3-Month Net Change
- ☐ 6-Month Net Change
- ☐ 12-Month Net Change

Percent Monthly Changes:
- ☐ 1-Month % Change
- ☐ 3-Month % Change
- ☐ 6-Month % Change
- ☐ 12-Month % Change

Update



MEMBER ASSESSMENT RESOLUTION

The Bylaws of the Council of Petroleum Accountants Societies (COPAS) provide that Participating, Provisional, and International Societies and Academic Individual Members shall contribute to the fiscal requirements of COPAS to defray operating costs. Such contributions are proposed by the Board of Directors and approved by Council. The Board of Directors prepares and approves a budget for the forward year detailing the source and application of funds. An assessment rate for the amount of contributions for each Participating, International, and Associate Society and Academic Individual Member is then determined.

WHEREAS, to fund the activities of the COPAS organization for the forward year, an assessment basis must be established.

WHEREAS, Participating, Provisional, and International Societies require advance notice of COPAS membership assessments to prepare their society dues structure.

WHEREAS, the annual membership renewal process is now August 1.

WHEREAS any increase to the assessment for the 2026 membership year must be approved by the Council at the Spring Council Meeting

WHEREAS, for the 2027 membership year, and subsequent years, must be approved by the Council at the Fall Council Meeting.

It is Resolved:

1. The assessment rate for the future years will be approved by the Council and shall be the basis for the assessment.

2. Participating, Provisional, or International Society which is admitted to membership in the Council during the fiscal year shall be assessed on the approved rate for that year on a prorate basis for the remaining portion of the year beginning on the first of the month following admission multiplied by the number of members in the membership listing presented with its Application, the product of which will be the amount due from the newly admitted Society.

3. Participating, Provisional, or International Society memberships will automatically renew on August 1 of each year using the membership assessment rate approved by Council.

4. Each Participating, Provisional, or International Society shall notify the COPAS Office of membership additions that might have been achieved outside the membership process implemented in 2024. The COPAS Office shall invoice the Society for a full assessment for each member added through June 30; new members added after June 30, and prior to the final Society listing for the subsequent year's assessment, shall not be invoiced.

This resolution was amended by the COPAS Board of Directors on February 19, 2025, replacing the resolution approved on December 6, 2021. The resolution is effective with the member assessment for 2026 and thereafter.

Turning Energy Into Synergy

Well Cost Allocations and Adjustments

ACCOUNTING GUIDELINE 1

Publication/Revision Date - April 2003

Council Approved

PRUTCOM Approved: January 28, 2025

COPAS Accounting Guideline 1

WELL COST ALLOCATIONS AND ADJUSTMENTS

CONTENTS

This document has been reviewed by the Petroleum Accountants Societies through representation on the Council of Petroleum Accountants Societies. It is recommended that the contents of the document be used as a guide to joint interest operations accounting. The

Council appreciates the contributions of the Petroleum Accountants Society of San Juan Basin for research and publication of this document.

FOREWORD

The objective of this document is to provide guidance for two accounting issues: 1) equitable apportionment of costs and expenses for Downhole Commingled Wells and Multiple Completion Wells, and 2) equitable Well Cost Adjustments for certain situations. **Refer to the COPAS publication AG-2, *Unitization Accounting,* for guidance on investments, adjustments pertaining to the formation of secondary recovery units, changes in federal exploratory units participating areas, and changes in drilling or spacing unit sizes.**

The information contained in this document is intended to aid in understanding and applying allocations/adjustments as well as negotiating future allocations/adjustments. No attempt has been made to include a suggested solution for all of the contingencies that may occur. It is also recognized that there may be more than one equitable solution to each situation. In these instances, alternate suggestions have been included. **The Joint Operating Agreement, Accounting Procedure, and other relevant agreements for a particular property will always take precedence and should always be taken into consideration.**

I. INTRODUCTION

Well cost apportionment and/or adjustment is needed when multiple formations with different ownership share a common wellbore. Cost and expense apportionment is necessary as a result of a Downhole Commingled Well or Multiple Completion Well. These types of wells are designed to economically benefit all the owners of different oil and/or gas producible formations by sharing in the costs and expenses of drilling and/or producing the different formations. Many of the goods acquired and services performed in connection with a Downhole Commingled Well and Multiple Completion Well directly benefit more than one formation. The costs of these goods and services that constitute Direct Costs need to be allocated to the formations that benefit. This document is intended to provide guidance in allocating these costs to the formations or otherwise reaching agreement on an acceptable means of cost reapportionment. Specific topics addressed include cost sharing for drilling a new Downhole Commingled Well and Multiple Completion Well, and cost reapportionment that may be necessary when recompleting an existing wellbore.

Even when the working interest ownership is the same in each of the objective formations in a Downhole Commingled Well and Multiple Completion Well, the issues may eventually need to be addressed. This is necessary because the ownership or participating interest of a formation could change, thus giving rise to equity concerns in the allocation of operating expenses, workover costs and expenses, and abandonment expenses. However, this is not a common occurrence. The governing Operating Agreement or other agreement will often establish the situations giving rise to the need for an adjustment and may provide the method of calculating such adjustment. See Exhibit 1.

Approval for a Downhole Commingled Well and Multiple Completion Well must be obtained from working interest owners of all affected formations under the provisions of the Joint Operating Agreement or pursuant to regulations or order of the agency having jurisdiction, e.g., a forced-pooling order. The Operating Agreement may further establish whether all working interest owners or only the consenting parties need to approve the Multiple Completion Well. The proposal to complete the well in more than one formation should separately identify the cost and expense apportioned to each formation and should be submitted to the non-operators entitled to such notice pursuant to the terms of the Operating Agreement for approval. If the parties do not have a written agreement establishing the terms for allocating costs between zones, it is advisable to enter into such an agreement prior to performing the operation.

A Cost Allocation Agreement (for a sample Cost Allocation Agreement see the Exhibits in COPAS AG-2, *Unitization Accounting*) can be made a part of the Joint Operating Agreement or it can be a separate, stand-alone agreement. Sometimes there are separate Operating Agreements for each formation, but the working interest owners of all the formations enter into a Cost Allocation Agreement that addresses the rights and obligations of each set of formation owners. Additionally, model form Operating Agreements may contain provisions concerning certain events that call for cost allocation or an investment adjustment and set out how those adjustments should be calculated. See Exhibit 1.

Absent agreement or contractual provisions to the contrary, the scope of audits covering investment adjustments will be limited to verifying the accuracy of the Well Cost Adjustments and the cost and expense apportionment to the Operator's records, and the accuracy of the apportionment decimals. Compliance with Accounting Procedure requirements of the existing owner's Operating Agreements for these historical costs may not be a right of the new owner(s), but rather a right only of the original owners, which may or may not have been exercised. The parties may mutually agree to make such audit rights available to the new owner(s), but such rights should be clearly set forth in the Cost Allocation Agreement or have another contractual basis.

II. NEW WELL COST APPORTIONMENT

This section addresses cost allocations for new wells being drilled with attempted completions in multiple formations. Well cost allocation may be necessary on new wells for a variety of reasons. Some of those reasons are ownership could be different between the different objective formations or working interest ownership could be the same and the participating interest might be different for two or more formations. Well cost allocation may also be necessary to calculate a tax basis for each objective formation, to determine the basis from which to separately calculate each producible formation's depletion, to facilitate the calculation of finding costs for each formation, or for a special situation. For example, a special situation would be that under offshore Operating Agreements, it is common to allow a party to limit its participation to the base of the deepest known producible horizon, so that it is non-consent on the deeper drilling, i.e., exploratory tail. This event may give rise to a cost allocation, as described in Section II.A.3.d.

Well costs are composed of the following cost categories:

A. Intangible Drilling Costs
B. Tangible Drilling Costs
C. Surface Equipment
D. Drilling Overhead

Each of these categories can require a different allocation method to allocate associated costs. Whichever methodology is used, whether listed in this document or not, the intent is for the parties to select an allocation methodology that is equitable for a given situation.

A. ALLOCATION OF INTANGIBLE DRILLING COSTS

Intangible Drilling Costs (IDC) are defined as those expenditures that are non-recoverable and, as such, have no salvage value. These costs are incurred in drilling and preparing wells for the production of oil and gas and normally end at the first connection beyond the Wellhead. For allocation purposes, Intangible Drilling Costs are categorized in the following three categories:

1. Shared Pre-drilling Costs
2. Shared Drilling Costs
3. Formation Specific Costs

A different allocation method is generally used for each of these Intangible Drilling Costs categories.

1. Shared Pre-drilling Costs

   Shared Pre-drilling Costs are IDC that arise from preparing a site for drilling, and they benefit all objective formations in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Pre-drilling Costs are site surveys, site preparation, right-of-way, surface damage payments, water supply wells, etc. These examples are not meant to be all-inclusive. Shared Pre-drilling Costs are typically allocated equally between all objective formations. The parties may agree to another equitable allocation method.

2. Shared Drilling Costs

   Shared Drilling Costs are IDC that are intended to benefit more than one formation in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Drilling Costs are rig costs, drilling water, field supervision, Drilling Overhead, etc. These examples are not meant to be all-inclusive. Allocating the Shared Drilling Costs to the objective formations is a two-step process. The first step is to associate the Shared Drilling Costs to the applicable Drilling Interval(s) and the second step is to allocate the applicable Drilling Interval's associated costs to the objective formations. There may be Intangible Drilling Costs that are treated as Formation-Specific Costs in one instance that are allocated as Shared Drilling Costs in other instances. The Operator should make reasonable efforts to charge Formation-Specific Costs to the benefiting formation, see sub-section 3 below, "Formation-Specific Costs."

   Listed below are descriptions and examples of several methodologies that may be used to allocate Shared Drilling Costs in a given situation. Whichever methodology is used, whether listed or not, the intent is for the parties to select an allocation methodology that is equitable for a given situation. Some equitable methods of allocating the Shared Drilling Costs are:

a. Day ratio: The first step is to determine the factor for allocating Shared Drilling Costs for the applicable Drilling Interval(s). The allocation factor is determined by a fraction of which the numerator is the number of days to drill through that Drilling Interval and the denominator is the total number of drilling days spent on the well. The total number of drilling days begins on the spud date and terminates when the completion election is made. Since rig costs are the largest expense and deeper drilling is generally slower than shallower drilling, the drilling day ratio may more closely align the costs with the Drilling Interval incurring the costs than will the Footage Ratio methodology.

   Step two is to allocate each Drilling Interval's costs to the objective formations. If using the Day Ratio methodology to allocate Formation-Specific Costs, step two is not applicable because doing so would improperly result in the lower formation(s) being allocated a portion of the completion costs for the upper formation(s). The first Drilling Interval's costs are allocated equally to all formations with each owner standing a proportionate share based on its respective participating interest in each formation. The second Drilling Interval's costs are allocated equally to all objective formation(s) below the base of the first objective formation. This allocation continues through the last Drilling Interval.

   Illustration:
   A party proposed drilling a well and completing it in three objective formations. The well was drilled in 75 days. If the time from spud date to the base of the first objective formation, the first Drilling Interval, took 27 days, all objective formations would receive 1/3 of 27/75 of the Shared Drilling Costs. If the time required to drill from the base of the first objective formation to the base of the second objective formation, the second Drilling Interval, took 11 days, then 11/75 of the Shared Drilling Costs would be divided equally between the second and third formations. If the time required to drill from the base of the second objective formation to the base of the third objective formation, the third Drilling Interval, took 37 days, then 37/75 of the Shared Drilling Costs would be charged to the third objective formation.

b. Footage ratio: The first step is to determine the cost allocation factors for the applicable Drilling Interval(s). The factor used for the first Drilling Interval is determined by a fraction of which the numerator is the footage drilled from the surface to the base of the first objective formation, and the denominator is the total footage drilled for the entire well. The factor used for the second Drilling Interval is determined by a fraction of which the numerator is the footage drilled from the base of the first objective formation to the base of the second objective formation, and the denominator is the total footage drilled for the entire well. This process continues through the last objective formation. Each factor is multiplied by the costs to be allocated to determine the applicable Drilling Interval's costs. Rather than calculating a unique set of factors for each well, the parties may agree to use an average relative footage by objective formation for similar wells in an area.

Step two is to allocate the applicable Drilling Interval's costs to the objective formations. The first Drilling Interval's costs are allocated equally to all formations with each owner standing a proportionate share based on its respective participating interest in each formation. The second Drilling Interval's costs are allocated equally to the objective formation(s) below the base of the first objective formation. This allocation process continues through the last Drilling Interval. Rather than calculate a unique set of factors for each well, the parties may agree to use an average relative footage by objective formation for similar wells in an area. It should be noted that deeper drilling is usually slower, and thus more expensive than drilling the shallow portion of the well. Consequently, using footage ratios to allocate the costs does not consider the additional expense involved in deeper drilling and, therefore, may not align the costs with the Drilling Interval contributing the most costs.

Illustration:
A party proposed drilling a well and completing it in three objective formations. The well was drilled to a total depth of 14,000 feet. If the footage from the surface through the first objective formation, the first Drilling Interval, is 12,000 feet, then 12,000/14,000, or 85.72%, of the Shared Drilling Costs would be allocated equally to all objective formations. If the footage from the bottom of the first objective formation through the second objective formation, the second Drilling Interval, is 1,000 feet, then 1,000/14,000, or 7.14%, of the Shared Drilling Costs would be allocated equally to the second objective formation and the deeper objective formation. If the footage from the bottom of the second objective formation through the third objective formation, the third and final Drilling Interval, is 1,000 feet, the third objective formation would be allocated 1,000/14,000, or 7.14%, of the Shared Drilling Costs.

c. Percentage of historical actual: The first step is to determine the factor for allocating Shared Drilling Costs to the applicable Drilling Interval(s). First, for each objective formation, take a recent historical sample of Shared Drilling Costs on a stand-alone basis, i.e., as a single-completion well. This method requires careful cost comparison between the same geographical area and the same time period, as well as consideration of similar well specifications. The factor for a given Drilling Interval is determined by a fraction of which the numerator is the total historical shared expenditures to drill a stand-alone well in a given objective formation, and the denominator is the total historical Shared Drilling Costs attributable to all wells in the historical sample. If the drilling operations experienced unusual circumstances that resulted in cost overruns, the cost overruns should be excluded from historical costs in calculating the factors. Likewise, the parties should reach an agreement that any unusual costs, inconsistent with the historical costs, will be borne by the formation or Drilling Interval giving rise to the costs.

Step two is to allocate the applicable Drilling Interval's costs to the objective formations. If using the Percentage of Historical Actual methodology to allocate Formation-Specific Costs, step two is not applicable because it improperly results in the lower formation(s) being allocated a portion of the completion costs for the upper formation(s). The first Drilling Interval's costs are allocated equally to all formations with each owner standing a proportionate share based on their respective participating interest in each formation. The second Drilling Interval's costs are allocated equally to the objective formation(s) below the base of the first objective formation. This allocation process continues through the last Drilling Interval.

Illustration:
A well is completed in three objective formations. Historical Shared Drilling Costs for stand-alone wells completed or attempted to be completed in three objective formations for the three Drilling Intervals are \$2,000, \$4,000 and \$6,000, respectively. The allocation of the Shared Drilling Costs is as follows: \$2,000 for Drilling Interval one is allocated equally to all three objective formations (1/3 of \$2,000 to each), \$4,000 for Drilling Interval two is allocated equally to the second and third objective formations (1/2 of \$4,000 to each), and \$6,000 for Drilling Interval three is allocated to the third objective formation.

d. Exploratory tail: This allocation method is used in special situations. For example, under offshore Operating Agreements, it is common to allow a party to limit its participation to the base of the deepest known productive horizon, so that it is non-consent on the deeper drilling, i.e., exploratory tail. This event may give rise to a cost allocation. There are a variety of ways to allocate the costs of a well with an exploratory tail. The most common way is for the parties participating in the shallow formation to pay the entire well costs to the base of the shallow formation, while the party or parties wishing to test the deep formation pay(s) 100% of the costs below the shallow formation. However, the parties may agree to use any of the other methods provided in this document.

3. Formation-Specific Costs

Formation-Specific Costs are intended to benefit a specific formation in a Downhole Commingled Well or Multiple Completion Well and do not benefit another objective formation. Examples of Formation-Specific Costs are electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc. These examples are not meant to be all-inclusive.

Formation-Specific Costs, in the vast majority of cases, are charged directly to the associated formation. These Formation-Specific Costs are identified from a detailed analysis of actual expenditures. This method would involve utilizing the well completion records as well as accounting records. This method is time-consuming and subject to getting useful information from operations personnel. More importantly, this method of charging Formation-Specific Costs requires information from the vendor regarding what formation it worked on, as well as additional invoice coding. If the parties believe the additional information gathering creates greater opportunity for errors, then the parties may consider another way to collect and allocate these costs on an equitable basis, particularly if there is an allocation basis that will reasonably match the cost to the formations.

The Operator should make reasonable efforts to charge Formation-Specific Costs to the benefiting formation. While this may require additional administrative effort in invoice processing, the objective is to assign costs to specific formations whenever possible because it is the most equitable way to ensure that each owner pays its respective share of the costs attributable to its formation. Charging as many Formation-Specific Costs to the benefiting formation as possible, rather than using an allocation method, will generally result in fewer audit exceptions, unless the parties specifically agreed to use an allocation method.

There may be costs that are treated as Formation-Specific Costs in one instance that are allocated as Shared Drilling Costs in other instances. For example, drill bits are often used to drill through more than one Drilling Interval because the Operator does not stop to change the drill bit at the base of each Drilling Interval. Therefore, drill bit charges would be treated as Shared Drilling Costs and would be allocated. On the other hand, if one Drilling Interval uses an expensive, or otherwise specialized drill bit, it would result in a more equitable cost apportionment to charge the more expensive bit to the formation(s) that receive(s) the benefit. Other examples of costs that can either be allocated or treated as Formation-Specific Costs are mud, chemicals, or steerable motors to drill horizontal portions of the well. If the mud or chemicals used in the respective Drilling Intervals have minor variation, these costs could be allocated with other Shared Drilling Costs. However, if one Drilling Interval requires specialty mud or chemicals that differ in cost from the mud or chemicals used in the other formation(s), then these costs could be treated as Formation-Specific Costs to match the costs more closely to the benefiting formation(s).

Allocation of Formation-Specific Costs is not common because it does not match costs to the benefiting formation as closely as the detailed analysis and charging to specific formations. It is applicable where the formations have very similar, if not identical, drilling and completion plans. Assuming one has identified a situation where an allocation of Formation-Specific Costs will result in equitable charges to the applicable formations, and the parties are agreeable to using an allocation, there are several ways to allocate the costs.

Only "step one" of the allocation methods provided in Section II.A.3 for allocating Shared Drilling Costs may be used to allocate the Formation-Specific Costs. Step one of the allocation methodologies provides for the formation(s) benefiting from the costs to receive an allocated portion of the costs. Step two of the allocation methodology is not applicable because it results in a formation being allocated an unfair amount of the cost. Acceptable methodologies of allocating Formation-Specific Costs are:

a. Step one of Day Ratio: For more information on this methodology, refer to Section II.A.3.a. Although the methodology is the same, the allocation factor used to allocate Formation-Specific Costs will be different from the allocation factor used to allocate Shared Drilling Costs. Only drilling days should be used to calculate the factor for allocating Shared Drilling Costs, while only completion days should be used to determine the allocation factor for Formation-Specific Costs.
b. Step one of Percentage of Historical Actual: For more information on this methodology, refer to Section II.A.3.c. The Formation-Specific Costs allocation factor may differ from the Shared Drilling Costs allocation factor if this method is used to allocate both Shared Drilling Costs and Formation-Specific Costs. In determining the allocation factors for step one, use Formation-Specific Costs and not Shared Drilling Costs.
c. Negotiated Amounts/Rates: The parties would agree upon a fixed percentage or amount for the Formation-Specific Costs allocated to the applicable formation(s). This percentage could be based on estimates of current costs and/or an analysis of historical costs.

While it is uncommon to allocate Formation-Specific Costs, it is especially uncommon to use footage days methodology for that allocation since the formation depth is not strongly related to the Formation-Specific Costs.

B. ALLOCATION OF TANGIBLE COSTS

Tangible Costs are defined as those material items installed in connection with drilling and completing a well through the Wellhead. Tangible Costs are ordinarily considered to have salvage value regardless of whether such items may actually be salvaged after they are installed. Examples of Tangible Costs are casing and tubing. Tangible Costs intended to serve one specific objective formation are typically charged to that formation and do not undergo an allocation. Other Tangible Costs intended to serve more than one formation must be allocated to the formations intending to use the equipment. Examples of shared Tangible Costs include conductor and surface casing, packers that separate the formations in a Multiple Completion Well, or tubing in a Downhole Commingled Well.

Complications may arise in determining the amount of Tangible Costs each formation should bear. For example, casing and/or tubing can change in size and/or quality throughout the total depth of the well. A string of casing and/or tubing consists of materials of different weights and grades set at various depths. For the purpose of making an allocation, the total average cost of the casing and/or tubing string is usually used so that each formation or Drilling Interval is charged the same average cost for its apportioned share of the casing and/or tubing string. However, if the formations have significantly different equipment specifications, the parties may wish to reach agreement on charging the incremental costs to the formation(s) needing the more costly equipment.

Listed below are descriptions and examples of several methodologies that may be used to allocate Tangible Costs in a given situation. Whichever methodology is used, the intent is for the parties to select an allocation methodology that is equitable for a given situation. Acceptable methods of allocating shared Tangible Costs are:

1. Footage Ratio

   For more information on this methodology, refer to Section II.A.3.b.

2. Percentage of Historical Actual

   For more information on this methodology, refer to Section II.A.3.c.

3. Negotiated Amounts/Rates

The parties could agree upon a fixed percentage or amount. For example, if one formation requires significantly higher-grade material (for material that is used by both formations), the owner(s) could agree to first apportion the incremental costs to the formation requiring the higher-grade material and then agree upon an allocation for the remainder. Another example is the parties agreeing to share the conductor and surface casing equally – three formations agreeing to pay 1/3 each since each formation receives equal benefit.

It is not common to use drilling days as a factor in allocating Tangible Costs since the number of drilling days is not as strongly related to the amount of equipment used by each Drilling Interval.

If some tangible equipment serves only one formation and the costs are clearly identifiable, the costs should be charged only to the benefiting formation. Examples of this are separate tubing strings, submersible pumps in one formation, or a liner that is serving only the deep zone.

C. SURFACE EQUIPMENT

The term "surface equipment" refers to all jointly owned equipment on the surface, beyond the Wellhead, and is not necessarily limited to equipment located within the boundaries of the lease. Examples of off-site surface equipment are gathering lines and processing equipment.

The cost of acquiring and installing surface equipment that serves more than one formation is allocated by an equitable method, i.e., equal shares, or an allocation based on reserves, annual production, etc., to the formations served. Equipment serving only one formation is treated as a Formation-Specific Cost and charged to the associated formation. However, the parties may agree to another method of charging, such as including these costs in the pool of other costs to be allocated as shown above. Also, the parties need to consider surface equipment required by a party to take its production in-kind since the Operating Agreement may require that extra expenditures incurred in taking production in-kind are borne by the taking party and not the entire joint account.

D. DRILLING OVERHEAD

In addition to allocating Direct Costs, it may be necessary to allocate Drilling Overhead. The contract(s) governing the property, whether it is a Joint Operating Agreement or a separate Cost Allocation Agreement, should be thoroughly examined for various provisions that address how Drilling Overhead is to be charged. Most COPAS model form Accounting Procedures provide for a one-well Drilling Overhead charge for Downhole Commingled Wells. There may be Drilling Overhead provisions in a separate Cost Allocation Agreement or the cost allocation provisions in the JOA, in addition to provisions in the Accounting Procedure. If there are separate Operating Agreements for two or more formations, the parties may require an agreement that "bridges" the individual agreements. Users are cautioned to seek legal advice in the event the provisions of the various agreements conflict.

If charging Drilling Overhead using a combined fixed rate approach, the common practice is to charge Drilling Overhead as if it were a single completion well drilled to test the deepest formation, then allocate the Drilling Overhead to the Drilling Intervals in the same manner as the other Intangible Drilling Costs. If charging Drilling Overhead using a percentage basis, the costs are allocated to the Drilling Interval, and the development percentage overhead is applied to the respective Drilling Interval's allocated cost.

III. WELL COST ADJUSTMENTS AND OTHER PAYMENTS - EXISTING WELLBORES

Well Cost Adjustments are a reapportionment of wellbore costs between existing owners and new owners. This compensation is usually for the purchase of an ownership in a wellbore and/or equipment owned by the working interest owners receiving the compensation. This payment could cause revisions to the payout account balance. The payment of the compensation is usually the result of:

1. Change in size of a unit either voluntarily or to conform to laws, rules, or regulations of a regulatory body

2. Creation of field-wide units or reservoir units

3. Recompletion of a well in one or more new formations

4. Multiple completion of a well in one or more new formations

The Operating Agreement may prescribe an investment adjustment or payment upon the occurrence of certain events. For example, operations to deepen or sidetrack the well or to recomplete the well at a shallower depth for the purpose of completing additional formations may trigger a Well Cost Adjustment under the terms of the agreement. The Joint Operating Agreement or other separate agreement should be carefully examined for specific provisions governing the handling of these types of investment adjustments as they may differ from the guidelines that follow.

This document does not cover items 1 and 2 above as they are addressed in COPAS AG-2, *Unitization Accounting*.

A. INTANGIBLE DRILLING COST COMPENSATION

IDC compensation includes IDC related to the preparation of a wellsite for drilling of a well but should not include the IDC related to the completion of the formation(s). The fair value of the IDC compensation should first be established, then apportioned to the producible formation(s), and to formation(s) proposed for completion. In all IDC compensation methods described below, the compensation will be apportioned to producible formation(s) and to formation(s) proposed for completion. Whichever methodology is used, whether listed or not, the intent is for the parties to select a methodology that is equitable for a given situation. Once the IDC compensation is determined, the compensation can be apportioned using the methods described in Section II.A.

Methods for determining IDC compensation include:

METHOD A - Actual or Deemed IDC - Unit of Production Depreciation

In this method, the parties determine the actual or Deemed IDC and depreciate these costs based on units of production. When determining Deemed IDC, use current market cost for drilling a well similar to the existing well. The parties will have to reach agreement on the Deemed IDC since it is a theoretical number. This method also requires that the parties reach agreement on the estimated reserves. An advantage of Deemed IDC is that it avoids having to identify actual IDC (excluding completion costs) that could be difficult for old wells. A disadvantage of Deemed IDC is that current replacement value may overvalue an older well, even with the depreciation factored in.

Illustration:
A working interest owner of a well that is currently producing from only one formation is proposing to add an additional completion in a second formation and thus make the well a Multiple Completion Well or Downhole Commingled Well. Working interest owners A and B are participating parties in formation one and working interest owners C and D are participating parties in formation two. The actual IDC for the wellbore was determined to be $200,000. The project to complete to formation two will begin on 10/1/20. Production from formation one from inception through 9/30/20 is 10,000,000 Mcf. Remaining reserves for formation one are estimated to be 7,000,000 Mcf. The depreciated value is determined by dividing the actual $200,000 of IDC by the total estimated reserves to be produced over the life of the well, or 200,000/17,000,000. This calculation yields a depreciation rate of $.011764 per Mcf of production. Thus, the depreciated amount is 10,000,000 Mcf produced times the depreciation rate of $.011764, or $117,647. This leaves a non-depreciated IDC balance of $82,353. The $82,353 would then be allocated by an equitable method to formation one and formation two. If the allocation method yielded an equal split, formation two owners owe formation one owners $41,176 (50% of $82,353). The $41,176 would be paid to owners A and B based upon their working interest in formation one, and owners C and D would share this cost based upon their working interest in formation two.

METHOD B - Actual or Deemed IDC - Straight Line Depreciation

In this method, the parties determine the actual or Deemed IDC and depreciate the costs evenly over the economic life of the well or an agreed upon number of years. When determining Deemed IDC, use current market cost for drilling a well similar to the existing well. The parties will have to reach agreement on the Deemed IDC since it is a theoretical number. An advantage of Deemed IDC is that it avoids having to identify actual IDC (excluding completion costs), which could be difficult for old wells. A disadvantage of Deemed IDC is that current replacement value may overvalue an older well, even with the depreciation factored in. This method requires that parties reach agreement on the estimated life of the well or period of time over which to depreciate.

Illustration:
A working interest owner of a well that is currently producing from only one formation is proposing to add an additional completion in a second formation and thus make the well a Multiple Completion Well or Downhole Commingled Well. Owners A and B are participating working interest owners in formation one, and owners C and D are participating working interest owners in formation two. The actual IDC for the wellbore was determined to be $240,000. The project to complete to formation two will begin on 10/1/20. Production from formation one began on 3/1/90. The depreciable life of the well is 240 months based on the twenty-year reserve life. The monthly depreciation amount is $240,000 divided by 240, or $1,000 per month. The well produced from 3/1/90 to 10/1/20, or 127 months, resulting in $127,000 of depreciation. The non-depreciated value is the original IDC of $240,000 less the $127,000 depreciation, or $113,000.

The $113,000 would then be allocated by an equitable method to formation one and formation two. If the allocation method yielded an equal split, formation two owners owe formation one owners $56,500. The $56,500 would then be paid to owners A and B based upon their working interest in formation one, and owners C and D would share this cost based upon their working interest in formation two.

Note: For methods A and B, both parties A and B are participating parties, as are owners C and D. Thus, A and B share the payment in proportion to their working interest in formation one, while owners C and D pay the adjustment in proportion to their working interest in formation two. That would change if D went non-consent. In that case, only Party C would pay the adjustment. If B were non-consent in the well from the outset and the well had not paid out, only A would receive the payment (assuming the payment did not cause the payout account to reach payout). If B were a participating party in the drilling of the well, but went non-consent at casing point or on a subsequent operation, both A and B would receive the payment. Readers are cautioned to review their agreement carefully as some agreements may deviate from this general practice.

METHOD C - Full Replacement Value IDC Compensation

In a situation where the wellbore is servicing productive formation(s) that have been profitable, with many more years of production remaining, it may be acceptable for IDC compensation to be based on full replacement value compensation. Therefore, the value of the IDC would not be depreciated when determining compensation. To better understand when full replacement value compensation for IDC may be deemed to be proper, we should hypothetically ask the following question: "If the owners of the current productive formation(s) were faced with the decision to drill a replacement well at this time to enable production of the remaining reserves, would that be economically viable?" An advantage of using this method is that it does not require determining actual IDC, which could be a problem if the records are old. A disadvantage of using this method is that for an old well with a long reserve life, current replacement value may overvalue the asset.

METHOD D - Negotiated Amount

The parties may simply negotiate a fixed amount as compensation to avoid research of actual costs, estimates on current drilling costs, reserve estimates, or well life. The obvious advantage of this method is that it is simple and can be done quickly if the parties have a similar perception of the value. The disadvantage is that the parties have to negotiate in good faith. A mediator or arbitrator can help to facilitate an agreement. This method works particularly well where the same parties own an interest in the affected formations, and the ownership percentages do not change significantly. The settlement can range from salvage value to an estimate of current market value, or any other amount established by the parties.

B. COMPENSATION FOR SURFACE AND SUBSURFACE TANGIBLE EQUIPMENT

For some situations, such as adding a completion with different working interest ownership, compensation should be paid to the owners in the existing formation(s) for surface equipment and tangible subsurface equipment to the extent it will be used by the owners in the new completion. The Cost Allocation Agreement, if any, Accounting Procedures, or any other applicable agreement for the property should be reviewed for any allocation and pricing provisions under this circumstance. When using a COPAS Accounting Procedure method of valuing equipment, it will be necessary to determine if the equipment is in "B, C, D, or E condition" and determine the current new price. Alternatively, other agreements may call for other valuation methods such as fair market value. Tangible Equipment Compensation will be apportioned to producible formations and to formations proposed for completion. Methods for apportionment of Tangible Costs are described in Sections II.B and II.C.

Other ways to value the equipment include using salvage value or a negotiated amount.

IV. ALLOCATION OF OPERATING EXPENSES

Operating expenses need to be allocated since many of the costs are shared and need to be matched and charged to the formations receiving the benefit. Operating expenses fall into two categories: 1) Direct Costs and 2) Indirect Costs. For information on Direct Costs, refer to the provisions of each Accounting Procedure as well as interpretive material in other applicable COPAS publications.

A. DIRECT OPERATING COSTS

Some direct operating costs are clearly identifiable to and benefit only one formation. An example of this would be water disposal when only one formation produces water. Other direct operating costs are not clearly specific to a given formation and benefit more than one formation. Examples of this are routine labor costs or water disposal where all formations produce water.

Operating expenses that are clearly identifiable to a specific formation are normally charged directly to that formation. When an operating expense affects more than one formation, that expense should be allocated on an equitable basis to the formations receiving the benefit. A specific operating expense may be more heavily weighted to one formation over another, or the weight of a specific operating expense may fluctuate between formations from one period to the next, but a simple, consistent, allocation method will nonetheless result in an equitable allocation over a longer period of time. Bear in mind, it is often difficult to precisely measure the extent each formation benefited. Consequently, a fixed allocation percentage is typically used for all Direct Costs unless there is a material discrepancy for a given item or service.

The allocation percentages agreed upon should cover all operating expenses not identifiable to a specific formation. A contract pumper may charge more for a well completed in the Dakota formation than one completed in the Pictured Cliffs formation, but would probably charge a lesser amount than the sum of the two when operating a Multiple Completion Well. Similar examples, when reviewed, should support the premise that the agreed-upon percentages should cover all shared operating expenses.

Listed below are descriptions and examples of several methodologies that may be used to allocate Direct Costs in a given situation. Whichever methodology is used, whether listed in this document or not, the intent is for the parties to select an allocation methodology that is equitable for a given situation. Suggested allocation methods include:

1. Equal allocation among all formations,
2. A formula based on the state approved production allocation,
3. Other agreed upon percentages.

The most commonly used method to allocate direct operating expenses is the first method: equal allocation to all formations. Parties are encouraged to reach an agreement on the methodology, especially if using a method other than the first method.

B. INDIRECT OPERATING COSTS

Operating Overhead is discussed in the provisions of each vintage Accounting Procedure, as well as interpretive material in other COPAS publications. **The Joint Operating Agreement, Accounting Procedure, and other relevant agreements for a particular property will always take precedence and should always be taken into consideration.** The contracts that govern the property should be thoroughly examined for various provisions that address overhead. There may be overhead provisions in both the Accounting Procedures and the Cost Allocation Agreement, and users are cautioned to seek legal advice in the event these provisions conflict.

There is no allocation issue if operations are governed by an agreement allowing a one-well overhead charge for each produced zone. If, however, the Accounting Procedure or Cost Allocation Agreement stipulates the wellbore is only eligible for a one-well overhead assessment, the charge may be split as follows:

1. Equal allocation among all formations,
2. A formula based on the state-approved production allocation,
3. Other agreed upon percentages.

If operations use the percentage basis method (versus fixed rate method) of assessing Operating Overhead, each zone's share of Operating Overhead is its allocated share of operating cost times the Operating Overhead percentage.

V. WORKOVER OPERATIONS

A. ALLOCATION OF COSTS FOR WORKOVER OPERATIONS

A proposed workover, repair, or other operation - excluding routine repair or maintenance work - usually requires approval by the parties owning a participating interest in all formations which are capable of producing in paying quantities, whether or not such formations are to undergo the proposed workover, repair, or other operation. However, some Joint Operating Agreements, particularly Unit Operating Agreements, may provide the operation is deemed approved if a certain threshold vote is reached, regardless of whether the formation is capable of producing in paying quantities. The costs and risk of any workover, repair, or other operations on such well are borne by the parties electing to participate in such workover, repair, or other operations as follows:

i. The costs and risk of any workover, repair, or other operation which is directly related to one formation, including but not limited to operations such as re-perforating the casing or stimulating the formation, are borne by the formation which the workover, repair, or other operation is intended to benefit.

ii. All costs and risk of any workover, repair, or other operation not directly related to one formation, including but not limited to repair and correction of leaks that may result in communication between formations within the wellbore, are borne equally by the formations benefiting from such work, unless a different percentage is negotiated between owners.

iii. For information on allocating workover overhead costs, refer to Section II.D or IV.B, as applicable.

iv. Any material and equipment acquired by, and such expenditures incurred in connection with, the workover, repair, or other operation are paid for and owned by the respective formations so as to be consistent with the ownership of the material and equipment as described in Section II - "New Well Cost Apportionment."

B. DAMAGES

If the producing capacity of the formation(s) not undergoing the workover, repair, or other operations is reduced, damages may be deemed to have occurred. When the issue of damages is addressed up front in an agreement, the parties may agree upon a threshold reduction in the damaged formation's capacity before damages are due. Moreover, it is common to limit the liability to the cost of drilling and completing a replacement well. If damages occur, the owners of the formation undergoing workover or repair may agree, or otherwise be required, to pay damages to the owners of the damaged formation(s) for the loss of production capacity. The damage payment is typically made to the participating owners in the damaged formation, rather than all the working interest owners. Owners are advised that damage payments could affect payout calculations. Payments that might be owed to royalty owners for damages in this situation are beyond the scope of this document, and readers should seek appropriate legal advice on this issue.

The parties may agree, however, that liability for loss or damages will not accrue if: 1) the loss or damage existed prior to actual commencement of the operations or prior to penetration by recompletion equipment of the damaged formation, or 2) the loss or damage resulted solely from the previously existing poor mechanical condition of the well. **The Joint Operating Agreement, Accounting Procedures, and any other applicable agreements for a particular property will always take precedence and should always be reviewed.**

VI. ABANDONMENT

This section addresses wells having different working interest ownerships. It is not intended to address non-consent situations where the working interest ownership is uniform, but the participating interest differs. Also, the term "owners" usually refers to the participating parties in the well or operation, so that payments by and to owners of a formation involve only the consenting parties and the payout account adjusted accordingly. However, the relevant agreements should always be reviewed to ensure the proper accounting treatment.

A. PARTIAL ABANDONMENT - NON-PRODUCTIVE FORMATION

If a well that began with the objective of multiple completions results in discovery of oil and/or gas in paying quantities in one or more formation(s) but is not producible in one or more formation(s), the common practice is for the costs of drilling, testing, and completing the well to be allocated as stated in Section II above, rather than being retroactively reallocated. Similarly, the costs to equip the well prior to the decision to abandon the non-productive formation(s) are borne by all objective formation(s). All costs of equipping the well subsequent to the decision to abandon the non-productive formation(s) are typically borne by the productive formation(s). If there are two or more productive formations, the owners of these formations share any remaining equipping costs to the extent the equipment benefits both productive formations. The productive formation owner(s) then own(s) all materials and equipment acquired from the non-productive formation owner(s), including non-salvageable material, depending on the agreements reached between the parties.

Typically, the productive formation owner(s) pay to the owner(s) of the non-productive formation(s) that are being abandoned, the fair value of any salvageable material and equipment paid for or furnished by the abandoning non-productive formation(s) and that is used in connection with the productive formation(s). Another method of valuing equipment is to use COPAS pricing mechanisms. The value of the equipment is based on its condition at the time the decision is made to abandon the non-productive formation(s). Likewise, the owners of the abandoned formation could agree to take no compensation for materials or equipment in exchange for the productive formation owner(s) paying for plugging costs of the abandoned formation.

The owners of the productive and non-productive formations may negotiate some other method of compensation for equipment acquired from the owner(s) of the non-productive formation. The cost of abandoning the non-productive formation(s) is borne by the owners of the formation(s) being abandoned in accordance with the applicable Operating Agreement. The cost to plug and abandon the rest of the wellbore is typically borne by the productive formation owner(s) when it is time to abandon the wellbore. The parties could agree that the owners of the non-productive formation(s) will share some of the costs to plug and abandon the rest of the wellbore at the time it is plugged, but this treatment is uncommon.

If the well being drilled had an exploratory tail and the upper interval is non-productive, the parties may need to negotiate a Well Cost Adjustment or disproportionate spending arrangement to compensate the shallow owners for takeover of the wellbore owned by the upper interval owners.

In any event, the Joint Operating Agreement, Accounting Procedure, Cost Allocation Agreement, or other relevant agreements for a particular property will always take precedence and should always be reviewed.

B. PARTIAL ABANDONMENT AFTER COMPLETION OF WELL IN MULTIPLE FORMATIONS

If fewer than all formations are abandoned in a Multiple Completion Well or Downhole Commingled Well, and the formation(s) being abandoned previously produced, then it is common for the remaining producible formation owner(s) to pay the abandoned formation(s) salvage value of any materials or equipment belonging to the abandoned formation(s) that are used in connection with the producible formation(s). If payment is made and there is more than one producible formation, payment is apportioned between the formations so as to be consistent with the ownership of material and equipment previously allocated. Once payment is made, the owners of the remaining productive formation(s) own all materials and equipment so acquired. Less commonly, the owners of the abandoned formation(s) could agree to take no compensation for materials or equipment in exchange for the owners of the productive formation(s) paying for plugging costs of the abandoned formation(s).

The cost of abandoning the formation(s) that is/are no longer producible or economic is borne by the owners of the formation(s) being abandoned in accordance with the applicable Operating Agreement. The cost to plug and abandon the rest of the wellbore is typically borne by the owners of the remaining productive formation(s) when it is time to abandon the wellbore. Uncommonly, the parties could agree that the owners of the non-productive formation(s) will share some of the costs to plug and abandon the rest of the wellbore at the time it is plugged. **The Joint Operating Agreement, Accounting Procedure, Cost Allocation Agreement or other relevant agreements for a particular property will always take precedence and should always be reviewed.**

C. ABANDONMENT IN ALL FORMATIONS

If all formations in a Multiple Completion Well or Downhole Commingled Well are plugged and abandoned at the same time, a common practice is to allocate the costs by charging Formation-Specific Costs for plugging and abandonment to the affected formation and sharing the non-specific costs equally. This could be accomplished by a detailed review of the plugging reports and vendor invoices, which can be tedious. Another way to allocate the plugging and abandonment costs is to allocate the costs based on rig days incurred for specific formations. Yet another way is to agree to a flat amount or percentage split. If using this approach, the parties need to take into account technical problems that could occur with any of the formations and charge the additional costs to the formation giving rise to the extra costs.

VII. CONCLUSION

A review of the various model form operating agreements, cost allocation agreements, and industry practice reveals a variety of ways Well Cost Adjustments are handled. The conclusion drawn from that variety is that there is no singular "right way" to make adjustments. Rather, it is a matter of discussion and negotiation among the parties acting in good faith to reach an allocation or settlement of costs that is equitable to all parties. Despite the terms of an existing agreement that clearly establishes an adjustment method, the parties can always reach mutual agreement to do otherwise. The parties are continuing to find ways to improve and/or streamline the adjustments.

GLOSSARY

The definitions provided in this glossary or in other sections are not intended to conflict with their generally accepted meaning as used by the oil and gas industry, but are provided here as a matter of convenience and clarification as to their specific meaning under this document:

ACCOUNTING PROCEDURE - An agreement between the parties to joint operations, often an attachment to the Operating Agreement that establishes the terms and conditions for accounting for the joint operations.

COST ALLOCATION AGREEMENT - An agreement that establishes the terms and conditions for cost and expense apportionment among formations in a Downhole Commingled Well or Multiple Completion Well. A Cost Allocation Agreement is usually made a part of the Joint Operating Agreement, but it may be a separate agreement, particularly if each formation has its own, separate, Joint Operating Agreement. For a sample see COPAS AG-2, *Unitization Accounting*.

DEEMED IDC - An estimate of Intangible Drilling Costs to drill a replacement or like well in the current market for that given area.

DIRECT COSTS - Those costs chargeable to the joint account under the direct charges section of the COPAS model form Accounting Procedures, i.e., Section II of the COPAS 1962, 1968, 1974, 1976 Offshore, 1984, 1986 Offshore, and 1998 Project Team Model Form Accounting Procedures, and Sections III and IV of the COPAS 1995 Model Form Accounting Procedure. For information on direct costs, refer to the provisions of each COPAS model form Accounting Procedure as well as interpretive material in other applicable COPAS publications.

DOWNHOLE COMMINGLED WELL - A well that produces hydrocarbons from two or more hydrocarbon-bearing formations through a common wellbore, mixed in the wellbore, and produced through a single tubing string. This type of well is distinguished from a Multiple Completion Well, which produces from two or more formations through separate tubing strings to each formation. There are usually two reasons to downhole commingle hydrocarbon production and produce it through a single tubing string: 1) a governmental regulatory agency requires the hydrocarbon production from two or more formations to be pooled and the production reported as a single well, or 2) the owners believe it is economically beneficial to all owners for the hydrocarbons to be mixed in the wellbore and produced through a single tubing string. A well can be both a Downhole Commingled Well and a Multiple Completion Well. A well can have two formations that are downhole commingled and produced through a common tubing string while another formation in the same well is produced through a separate tubing string.

DRILLING INTERVAL - In a Multiple Completion Well or Downhole Commingled Well, the drilling process is broken down into Drilling Intervals. The first Drilling Interval is the drilling zone from the surface to the base of the first objective formation. The second Drilling Interval is the drilling zone from the base of the first objective formation to the base of the second objective formation. This process of breaking down the Drilling Intervals continues through the last objective formation.

DRILLING OVERHEAD - The amount billed by the Operator to recoup costs not directly chargeable to drilling, recompletion, or workover operations under the Accounting Procedures. For information on Drilling Overhead, refer to the provisions of each Accounting Procedure as well as interpretive material in applicable COPAS publications.

FORMATION-SPECIFIC COSTS - Those costs intended to benefit a specific formation in a Downhole Commingled Well and/or Multiple Completion Well and which do not benefit another objective formation. Examples of Formation-Specific Costs are electric logs, drill stem tests, coring, shooting, acidizing, perforating, squeeze jobs, etc. These examples are not meant to be all-inclusive.

INDIRECT COSTS - All costs, other than those deemed specifically to be Direct Costs. For information, refer to the provisions of each Accounting Procedure as well as interpretive material in other applicable COPAS publications.

INTANGIBLE DRILLING COSTS (IDC) - All costs, which in themselves have no salvage value and are necessary for and incident to drilling a well, attempting to complete a well in a formation, and preparing the well for production. Intangible Drilling Costs also occur when deepening, sidetracking, or plugging back a previously drilled oil or gas well, or an abandoned well, to a different formation.

JOINT OPERATING AGREEMENT (JOA) - An agreement between two or more parties providing for the development and operation of a tract or leasehold for the purpose of oil, gas, or other minerals extraction. The parties to the agreement share in the expenses of the operations and the production. The Joint Operating Agreement defines the rights and obligations of the co-owners of the working interest of a property in connection with the joint development and operation of the lease.

MULTIPLE COMPLETION WELL - A well producing from two or more formations by means of separate tubing strings run inside the wellbore, each of which carries hydrocarbons from a separate and distinct productive formation. In some cases, hydrocarbons may be produced through the annular space between the casing and tubing string instead of through a separate tubing string. The separate production strings distinguish this form of well from a Downhole Commingled Well that produces from two or more hydrocarbon formations through a single tubing string in the common wellbore. A dual completion well is a Multiple Completion Well having only two hydrocarbon productive formations. A well can be both a Downhole Commingled Well and a Multiple Completion Well. A well can have two formations that are downhole commingled and produced through a common tubing string while another formation in the same well is produced through a separate tubing string.

OPERATING AGREEMENT - See Joint Operating Agreement.

OPERATING OVERHEAD - The amount billed by the Operator to recoup costs not directly chargeable to the routine operation of the joint property under the provisions of the Accounting Procedure and /or other agreements governing the property. For information on Operating Overhead, refer to the provisions of each Accounting Procedure as well as interpretive material in other COPAS publications.

OPERATOR - The entity responsible for physical maintenance and operation of the well and other responsibilities as covered in the Joint Operating Agreement, unit agreement, force pooling order, or other governing document, and recognized as such by the agency having jurisdiction.

SHARED DRILLING COSTS - Intangible Drilling Costs that are intended to benefit more than one formation in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Drilling Costs are rig costs, drilling water, field supervision, Drilling Overhead, etc. These examples are not meant to be all-inclusive.

SHARED PRE-DRILLING COSTS - Intangible Drilling Costs that arise from preparing a site for drilling and benefiting all objective formations in a Multiple Completion Well and/or Downhole Commingled Well. Examples of Shared Pre-drilling Costs are site surveys, site preparation, right-of-way, surface damage payments, etc. These examples are not meant to be all-inclusive.

TANGIBLE COSTS - Those material items installed in connection with drilling and completing a well through the Wellhead, or deepening, sidetracking, or plugging back operations. Tangible Costs are ordinarily considered to have salvage value regardless of whether such items may actually be salvaged after they are installed.

TANGIBLE EQUIPMENT COMPENSATION - Compensation paid to the existing owners of a well for the fair value of the tangible equipment associated with the existing well.

WELL COST ADJUSTMENT - Represents compensation paid by one set of working interest owners to another set of working interest owners. This compensation is usually for the purchase of an ownership in a wellbore and/or equipment owned by the working interest owners receiving the compensation.

WELLHEAD - A term applied to the valves and fittings assembled at the top of a well to control the flow of production.

Exhibit 1

Well Cost/Investment Adjustments

LA C.U. - 1

Article 4 - Investment Adjustment (new well)
Payment is based on the original cost of the Unit Well, including casing, tubing and in-hole equipment, up to and including the wellhead connections. Also, pay for original cost of lease and operating equipment beyond the wellhead connections that is necessary for operations.

Article 14 – Revision of Unit Area
Adjustment is made on the depreciated value of the Unit Well, equipment & material on the effective date of the revision. The depreciated value of the Unit Well, equipment & material is calculated on the basis of the original investment costs (to the base of the Unitized Sand) and the charges and credits made to the joint account for investment items from inception to the effective date of the revision, including tangible and intangible drilling & equipping costs, but excluding operating costs. Depreciation is calculated on unit of production - the amount produced by the well from the Unitized Sand & any other sands prior to the revision effective date in proportion to the total reserves obtained by adding the amount so produced & the estimated recoverable reserves to be produced from the Unitized Sand from such well. However, the recoverable controlled tangible investment shall not decline in value below the condition percentage determined per the Accounting Procedure.

Article 18 – Abandonment
18.1 - If fewer than all parties want to P&A, the non-abandoning parties pay the abandoning parties for the estimated salvage value of materials & equipment, less estimated salvaging costs.

18.3 - Turning over unit well to wellsite owner

- Payment is based on the estimated salvage value of unit well, equipment & materials, determined per the Accounting Procedure, less estimated salvaging costs.
- Or investment adjustment is based on total depreciated value of the Unit Well, equipment & material applicable to that portion of the well used by the well-site owner. Depreciated value of the Unit Well, equipment and material is calculated on original investment costs (including charges and credits for investment items from inception to effective date well-site owner takes over, & including tangible & intangible drilling & equipping costs, but excluding operating costs). Depreciation is based on unit of production, provided the depreciated value of recoverable controlled tangible investment is not depreciated below the condition percentage determined per the Accounting Procedure.

Article 19 – Release of Lease
The non-releasing party pays the party wishing to release the lease for the equipment and material on the assigned lease based on the estimated salvage value, determined per the Accounting Procedure, less the estimated cost of salvaging.

AAPL Form 610-1977
Article VI.E - Abandonment; Article VIII.A - Surrender of Lease
The non-abandoning (non-surrendering) party pays the abandoning (surrendering) party for the salvable material and equipment, determined per the Accounting Procedure, less the estimated cost of salvaging, plugging and abandoning.

AAPL Form 610-1982
Article VI.B.4 - Sidetracking
Dry hole - Payment is based on actual costs incurred in drilling the well to the depth at which sidetracking is initiated.

Producer - Payment is based on the well's salvable materials & equipment to the depth at which sidetracking is initiated, determined per the Accounting Procedure, less the estimated cost of salvaging, plugging and abandoning.

Article VI.E - Abandonment; Article VIII.A - Surrender
Payment is based on the value of the salvable material and equipment, determined per Accounting Procedure, less the estimated salvaging, plugging and abandoning costs.

AAPL Form 610-1989
Article VI.B.4 - Deepening; Article VI.B.5 - Sidetracking
Dry hole - Payment is based on actual costs incurred in drilling the well to depth at which deepening/sidetracking is initiated.

Producer - Payment is based on actual cost incurred in drilling, completing and equipping, to depth at which deepening/sidetracking starts. The cost of salvable materials and equipment in the well and salvable surface equipment shall be determined per Accounting Procedure. Note: Deduct from the payment any amounts recouped out of proceeds of production, up to 100% of the costs.

Article VI.E - Abandonment, Article VIII.A - Surrender
Payment is based on the value of the salvable material and equipment, determined per the Accounting Procedure, less the estimated salvaging, plugging and abandoning costs, and surface restoration costs. If this calculation results in a negative value, the abandoning party pays the non-abandoning party.

Article VI.C.1 - An adjustment takes place if a drilling party non-consents a completion attempt and prior to payout the well is recompleted. If the party that non-consented the completion attempt participates in the recompletion, it must pay the consenting parties for the cost of salvable materials and equipment in the well pursuant to the completion attempt, insofar as the materials and equipment benefits the formation in which the previously non-consenting party is participating.

Rocky Mountain Unit Operating Agreement - Form 2, 1994
Article 1 - Salvage Value means the value of the materials and equipment in or appurtenant to a well, determined per the Accounting Procedure, less the reasonably estimated Costs of salvaging the same and plugging and abandoning (including reclamation of the surface) of the well.

Article 11 - Abandonment; Article 27 - Surrender
Payment is based on the Salvage Value.

Article 12 - Relinquishment by Non-Drilling Party
In the case of a deepening, sidetracking, or plugging back operations, if a non-drilling party owned an interest in the well immediately prior to the deepening, sidetracking, or plugging back, the consenting parties pay the non-consenting party its share of Salvage Value of the well.

Article 13.3 - Adjustment on Establishment or Enlargement of Participating Area
Intangible Value - The Costs incurred in drilling, completing and equipping that contribute to the production of unitized substances from the resulting area. The Costs are reduced for each month the well was operated prior to the effective date of the resulting area by: X% per month for cumulative total of Y months, and Z% per month for each month in excess of the cumulative total.

Tangible Value - The Costs incurred in the construction or installation of Tangible Property are reduced at X% per month for each month during which well was operated prior to the effective date of the resulting area.
Article 13.4 - Adjustment on Contraction of Participating Area – See form.

API Model Form Offshore Operating Agreement - 1984
Article 12.3 - Deepening a Non-Consent Well
A non-participating party in a drilling that is joining a deepening operation pays the participating parties in the well for its share of actual costs incurred in drilling and casing the well.

Article 12.8 - Allocation of Costs Between Zones (Single Completions)
For purposes of allocating costs on any well completed in only 1 zone in which ownership is not the same for the entire depth or the completion:

- Intangible drilling, completion & material costs from the surface to 100’ below the base of the completed zone charged to participating parties in that zone.
- Intangible drilling, completion, casing string, and material costs (except tubing) from 100’ below base of completed zone to TD charged to parties participating to total depth.

Article 12.9 - Allocation of Costs Between Zones (Multiple Completions)

- Intangible drilling, completion, and material costs (except tubing) from surface to 100' below base of upper completed zone are divided equally between completed zones.
- Intangible drilling, completion, casing string, and material costs (except tubing) from 100' below base of upper zone to 100' below base of second completed zone are divided equally between second zone and any other deeper completed zone. If the well is completed in additional zones, use the same process.
- Intangible drilling, completion, casing, and material costs (except tubing) from 100' below base of lowest zone to total depth are charged to parties participating to total depth.
- Tubing serving each separate zone is charged to the participating parties in that zone.
- If the zones are less than 100' apart, the distance between the base of the upper zone to top of next lower zone is allocated equally between the zones.

Article 12.10 - Allocation of Costs Between Zones (Dry Hole)

- Costs to drill, plug and abandon are charged to participating parties in each zone, same as if completed in all zones as proposed.
- Plugging and abandoning following a deepening, completion attempt or other operation, is at sole risk & expense of participating parties, subject to Section 11.5.

Article 12.11 – Intangible Drilling and Completion Allocations
For purposes of allocating costs under Articles 12.8 - 12.10, intangible drilling and completion costs, including non-controllable material, are allocated to the zones based on a drilling day ratio basis. The factor for each zone is based on a fraction for which the numerator is the number of drilling and completion days applicable to that zone and the denominator is the total number of days spent on the well, beginning on the day the rig arrives on location and terminating when the rig is released.

Article 14 – Abandonment
Payment is based on the current value of the well's salvageable material and equipment, determined per Accounting Procedure, less the estimated cost of salvaging, plugging and abandoning.

Article 15 – Withdrawal
Payment is based on the current salvage value less the estimated current cost of salvaging, plugging and abandoning, and removing all platforms and facilities.

AAPL Form 710, The Continental Shelf Operating Agreement (formerly the API Model Form Offshore Operating Agreement - 1996)
Article 10.10 – Wells Proposed Below Deepest Producible Reservoir
If there is a proposal to drill an exploratory well below the base of the deepest producible reservoir, a party may elect to limit its participation to the base of the deepest producible reservoir. If the well is completed and produces from deep zone, the deep participant reimburses the shallow participant for its share of actual well costs to the base of the deepest producible reservoir. The shallow participant reimburses the deep participant for its share of the actual well costs to the base of the deepest producible reservoir, in accordance with Article 12.4 upon (a) the well being plugged back to a horizon above the base of the deepest producible reservoir, or (b) the well is plugged and abandoned, or (c) the deep operation reaching payout.

12.4 – Deepening or Sidetracking Cost Adjustments
(a) Intangible drilling costs are valued at the actual cost incurred by the Participating Party.
(b) Tangible materials are valued as transfers of new material per the Accounting Procedure.
(c) For sidetracking, the values are reduced by the amount allocated to that portion of the well down to 100' below the point of sidetracking. The allocations are to be made in accordance with this AG-1, as amended from time to time.
(d) Amortization/depreciation is applied to the intangible and tangible values at the rate of X% per annum from the date the well commenced production to the date deepening or sidetracking operations commenced, provided the value of tangible materials shall not be depreciated below Y% of the value determined in subsection 12.4 (b).

Article 14 – Abandonment, Salvage, and Surplus
Payment is based on salvage value, determined per the Accounting Procedure, less the estimated cost salvaging and plugging.

Article 15 – Withdrawal

The Withdrawing party pays the estimated cost of plugging and abandoning and removing platforms and facilities, less the estimated salvage value, as determined per the Accounting Procedure. If the salvage value is greater than the estimated share of costs, non-withdrawing parties pay the difference to the withdrawing parties.

AAPL Form 810, Deepwater Operating Agreement

11.2.5 Participation in a Sidetrack or Deepening by a Non-Participating Party in an Appraisal Well at Initial Objective Depth.

A former non-participating party joining in the deepening or sidetracking of an appraisal well becomes under invested in an amount equal to its share of carried costs in the well to the objective depth prior to deepening or sidetracking. The original parties become overinvested. The underinvestment is eliminated through disproportionate spending.

13.2.5 Participating in a Sidetrack or Deepening by a Non-Participating Party in a Development Well at Initial Objective Depth

A former non-participating party joining in the deepening or sidetracking of a development well becomes under invested in an amount equal to its share of the carried in the well to the objective depth prior to the deepening or sidetracking. The original participating parties become overinvested. The underinvestment is eliminated through disproportionate spending.

13.3.1 Multiple Completion Alternatives Above and Below the Deepest Producible Reservoir

A party may elect to limit its participation in a well to the base of the deepest producible reservoir.

(a) If all parties agree to multiple completions both above and below the base of the deepest producible reservoir, the parties in the deeper drilling bear 100% of the costs of drilling below the deepest producible reservoir in excess of the original costs to drill and complete the well in the deepest producible reservoir.

(b) If the parties do not agree that multiple completions are possible, the first completion shall be in the deep zone and the non-participating parties in the deeper drilling are overinvested in the amount of their share costs to drill to the base of the deepest producible reservoir. The participating parties in the deep zone are under invested for that amount. The underinvestment is eliminated through disproportionate spending.

Once certain events occur (see agreement), the non-participating parties in the deep zone are deemed under invested and the participants in the deep zone are overinvested. The over/underinvestment is the amount equal to the carried party's share of the well cost down to the deepest producible reservoir, depreciated at the rate of ½% per month from the date deeper drilling commences until the date the non-participating party is entitled to share in the hydrocarbons from the deep zones. The depreciated value will not be reduced below Y% of the original underinvestment. The underinvestment is eliminated through disproportionate spending.

Article 17 – Withdrawal

A withdrawing party pays the non-withdrawing parties their estimated share of plugging and abandoning all wells, production systems, facilities and other equipment serving the property, less their share of estimated salvage value. The costs and salvage value are determined per the Accounting Procedure.

Article 18 – Abandonment

If fewer than all parties wish to abandon a well, the abandoning party pays the non-abandoning parties its proportionate share of the well's estimated plugging and abandonment costs, less the estimated salvage value. If the salvage value exceeds the plugging costs, the non-abandoning parties pay the abandoning party its share of the difference.

> If fewer than all parties wish to abandon a production system or facility, the abandoning party pays the non-abandoning parties its proportionate share of the estimated cost to abandon the production system or facilities, less the salvage value. If the salvage value exceeds the abandonment costs, the non-abandoning parties pay the abandoning party its share of the difference.

Council of Petroleum Accountants Societies

Turning Energy Into Synergy

Vendor Audits

ACCOUNTING GUIDELINE 9

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COPAS ACCOUNTING GUIDELINE 9
VENDOR AUDITS

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This Accounting Guideline has been reviewed by the Petroleum Accountants Societies through representation on the Council of Petroleum Accountants Societies.

I. INTRODUCTION

Disclaimer
The following document is published for informational purposes only, intended to provide guidance with respect to vendor audits in the petroleum industry. It is not the intent of this Accounting Guideline to substitute for a specific audit program which addresses a particular area of the service industry or the audit needs of the company for which the audit is performed. Vendor audits may be performed at any time, subject to the right-to-audit provisions in a written contract or purchase agreement, or to the cooperation of the vendor in those cases, in which audit rights are not expressly established. The auditor should use this Accounting Guideline as a guide in preparing a detailed audit program before beginning the audit effort.

Purpose
The overall purpose of performing a vendor audit is to

(1) Safeguard company assets,
(2) Evaluate the individual vendor,
(3) Reduce the auditing company's capital and operating costs,
(4) Act as a deterrent against unnecessary costs in the future, and
(5) Help identify possible improper behavior or unethical practices by either party.

(1) Safeguarding company assets - The overall aim of any audit effort is to safeguard company assets. This objective includes (a) evaluation of the adequacy of proper maintenance and care, (b) verification of optimum utilization, and (c) evaluation of recordkeeping with regard to valuation and maintenance cost.

(2) Evaluation of the vendor - The vendor selected for audit should be evaluated for financial responsibility, government and agency compliance, and business ethics.

(a) Financial responsibility - A determination should be made regarding the financial stability of the vendor.

- Was proper verification of the vendor's financial credibility performed before the contract was awarded?
- If noncurrent, is re-verification appropriate?
- Does the vendor appear to have adequate working capital?
- Are subcontractors or suppliers being paid promptly?
- Have any liens been filed by subcontractors against company-operated properties or assets?
- Does the vendor have the necessary equipment and skilled personnel to perform the service required?
- Does the vendor maintain the appropriate insurance coverage as required by contract?

(b) Government and agency compliance - The auditor should, to the extent possible, assess the business reputation of the vendor. A determination should be made as to whether the vendor is in general compliance with federal and state laws involving taxes, the environment, safety, and labor. The auditor should also briefly review any outstanding litigation in order to detect any possible operating pattern.

(c) Business ethics - Throughout the course of the audit, the auditor should be aware of a vendor's "corporate culture" and determine whether the vendor is an organization the auditing company wishes to be associated/involved with. Indicators that a vendor has a higher risk of improper or unethical behavior include the following:

- Does the vendor have an ethics policy or code of conduct?
- Is that policy properly communicated from management to all employees and subcontractors?
- Are there controls in place to provide the appearance of detection?
- How is the vendor viewed in the community?;
- Does the vendor have a reporting tool (e.g., a hotline)?

(3) Reducing capital and operating costs - By reviewing transactions between the vendor and the company the auditor is representing, the auditor may detect errors and obtain refund credit, thereby reducing drilling, operating, or construction costs. These overcharges may be the result of accounting errors or may represent charges which are inconsistent with the provisions of contracts or sales agreements.

(4) Deterrence - Through periodic reviews of individual companies within the oilfield service or construction industry, the audit coverage acts as a deterrent against future overcharges or other problems. The auditor can alert their company to a problem area. This notice should ultimately lead to corrective action by the vendor. As a result, the likelihood of future incidence of unsafe, unethical, and/or unnecessarily costly practices is reduced.

(5) Identification of possible improper or unethical practices - The auditor should be, to the extent possible, conscious of signs of improper behavior or unethical practices by any party or individual involved. This awareness should include the vendor, the subcontractors, and the auditing company. Violations may include:

(a) Fictitious shell entities set up by employees or others that may or may not provide goods or services,
(b) "Substitution-of-materials" schemes that supply faulty or inferior goods,
(c) Incomplete shipments or goods not delivered,
(d) Services allegedly performed that were not needed, or service(s) never performed,
(e) High prices charged when the goods can be bought directly or less expensively from the same or another vendor, and

(f) Corruption schemes, including improper payments and kickbacks, conflicts of interest, gifts and gratuities to company employees, and commissions to brokers and others.

Objectives

Although the specific objectives of each audit will vary, the general objectives of every vendor audit should be to:

(1) Determine whether a company has been invoiced correctly,

(2) Verify the vendor is in compliance with the terms and conditions identified in a contract that is in place,

(3) Establish the vendor is performing in an ethical manner,

(4) Ascertain the adequacy of the auditing company's as well as the vendor's control procedures, and

(5) Establish a personal rapport and lines of communication for possible future audits.

Benefits

Some of the benefits of performing a vendor audit include:

(1) Cost recovery from identification of billing errors and prevention of future billings errors,

(2) Mitigation of risk exposure due to noncompliance,

(3) Improvement of internal processes,

(4) Enhancement of the relationship between a company and a vendor, and

(5) Identification of vague or ambiguous contract language.

Types of Audits

Cost recovery audits, similar to joint venture audits, focus on reviewing invoices to determine the accuracy and validity of the charges as well as compliance with the terms and conditions of the contract (if one exists). Billing errors can include, but are not limited to, incorrect mark-ups, costs covered by overhead, incorrect labor rates, duplicate payments, omitted discounts, miscalculated charges, and/or incorrect taxes.

Policy or systems audits are performed to determine compliance with governmental agency and company policies (e.g., safety, drug/substance abuse, environmental regulations, ethics/code of conduct, etc.) or to review and determine weaknesses within the vendor's systems (e.g., allocations, purchasing, accounts payable/receivable, record retention).

Fraud investigations can be complex, tedious, and challenging. They require the use of many skill sets, from data analysis to interviewing techniques and forensic accounting. They are best performed by or under the direction of a qualified auditor who has previous experience with fraud investigations and understands the possible legal ramifications.

Types of Vendors

Most vendors or contractors in the oil and gas industry will generally fall into one or more classifications (e.g., EPC firms perform engineering, procurement, and construction services), each with unique characteristics or questions to ask.

(1) Drilling contractors - Drilling contractors typically provide drilling services based on either a daywork (charge a daily rate), footage (charge per foot drilled), or turnkey (lump sum) contract. Additional charges may include mobilization/demobilization rates, reimbursable costs, repair to equipment, work stoppage rates, and/or hazardous material/safety bonuses.

(a) What is included in the mobilization/demobilization rates?
(b) What items are considered reimbursable or should be provided by the drilling contractor?
(c) How much time is allowed for equipment repair and does the contractor receive the full operating rate?
(d) In what situations does the work stoppage rate apply?
(e) What documentation is included with the invoice (e.g., tour reports)?

(2) Suppliers - Suppliers provide various materials, from nuts and bolts to casing, pipe, pumps, and valves. Suppliers typically charge per unit and may offer discounts for bulk orders, repeat customers, and/or paying invoices early.

(a) Who pays for transportation costs?
(b) Are supplies taxable, and, if so, have they been calculated correctly?
(c) Do the materials received match the materials identified on the purchase order?
(d) Were any credits given/received for any unused/returned materials?
(e) Are the materials properly and fully described on the invoice?

(3) Consultants - Consultants can include engineers, auditors, environmental specialists, and many other professionals. Costs will generally be based on hourly labor rates, which may be "bare" (do not include payroll benefits and burdens) or "fully loaded" (include a percentage to cover payroll benefits and burden costs). Additionally, consulting companies may charge mark-up/overhead fees for office supplies, software usage, utilities, etc.

(a) Are the labor rates fully loaded, and, if so, what costs are included in the rates and how are the rates determined?
(b) How are the mark-up/overhead fees applied?
(c) What are the mark-up/overhead fees intended to cover?
(d) Review timesheets to determine the validity and accuracy of time periods and hours charged.

(4) Construction - The largest portion of construction costs will be for labor expense (both manual labor and supervision), subcontractors, materials, equipment, and mark-up/overhead fees to cover items such as consumables or small tools. There may also be charges for items such as insurance, bonds (performance or warranty), relocation and travel, and permits and licenses.

(5) Service providers - Service providers can include cementing, mud, fracturing, seismic, or inspection companies. Service providers will typically charge per unit (hourly, volume pumped, etc.).

(a) Was the service company providing services to others in the surrounding area?
(b) Are services taxable; if so, have the taxes been calculated correctly?
(c) Was work performed on the correct property or project?
(d) What labor costs (e.g., operator) are included in equipment or time-based (daily/hourly) rates?
(e) Was a full description of the services provided?

Types of Contracts
Although every contract is unique, many contracts or agreements will fall into one of these categories, based on billing methodology.

(1) Time and materials - Under time and materials contracts, vendors typically use predetermined rates (which include factors for overhead and profit) for labor, equipment, and materials. For example, a construction company may charge customers a flat hourly rate of $100 for welders but may pay their welders only $20 to $40 per hour. A time and materials contract increases the customer's risk because if project costs go over budget, the customer is responsible for the increase in costs. Additionally, unless a provision in the contract addresses the issue, a time and materials contract can adversely reward a vendor for increasing costs (e.g., the higher the costs, the greater the profit).

(2) Lump sum - In a lump sum or fixed fee contract, a vendor agrees to provide specified services and/or materials for a specific price. The customer agrees to pay the price upon completion of the work or according to a negotiated payment schedule. In developing a lump sum bid, the vendor will estimate the costs of labor and materials and add to it a standard amount for overhead and desired profit. A lump sum contract increases the vendor's risk because if project costs go over budget, the vendor's profit is diminished. However, if the project is completed under budget, the vendor increases its profits. Two keys to auditing against a lump sum or fixed fee contract are (1) verifying payments made on a payment schedule equal 100% of the contract value and (2) verifying any change orders billed were approved by company project management.

(3) Cost reimbursable or cost-plus - A cost reimbursable or cost-plus contract is similar to a time and materials contract except that costs are reimbursed as they are incurred; then mark-ups are applied to the subtotal. For example, a contractor would bill its $20 to $40 per hour welders to the customer at cost, plus a 5% mark-up for overhead, a 3% mark-up for consumables, and a 7% mark-up for profit. The key to auditing against a cost reimbursable or cost-plus contract is verifying the original cost (i.e., did the construction company really pay its welders $20 to $40 per hour, or did it pay them $15 to $35 per hour?) The customer assumes a greater

portion of the risk involved in a cost reimbursable or cost-plus contract, similar to a time and materials contract.

(4) Unit price - In a unit price contract, the work to be performed is broken into segments, or units. As the vendor completes each segment, a price agreed upon by both parties is charged. For example, a drilling contractor using a unit price contract may charge $200 per foot drilled for a 15,000-foot well. The per foot price includes the vendor's labor costs, materials, equipment usage, repair costs, overhead, and profit.

II. AUDIT PROGRAM

Vendor Selection

The selection of a vendor/contractor may take place for one of the following reasons:

(1) Management request - The audit may be requested specifically by operating management as a result of problems encountered through poor performance or cost overruns. Another reason would be for performance evaluation of current efforts in advance of considering the vendor for a significantly larger project.

(2) Risk analysis - The auditor may assess the potential risk to the company posed by various vendors. The type of contract may dictate the need for an audit of the vendor. For example, a cost-plus versus a lump sum arrangement would normally require more intensive scrutiny.

(3) Selected by the auditor - Possible selection criteria include:

   (a) The amount of business conducted with vendor. If possible, determine the percent of sales the auditing company represents to the overall sales of the vendor. A reputable financial business report might be a source from which to gather total vendor sales. Those vendors with a higher percentage are likely to be better audit candidates.
   (b) The reputation of the vendor within the oil and gas industry.
   (c) Demonstrated nonperformance under a previous contract or agreement.

(4) Statistical sample - The auditor may make all selections of audit candidates using a purely statistical sample based on predetermined limits and rates of expectancy.

If the vendor audit is to be performed as a part of an internal operational audit, the selection will be representative of the services obtained by the operating group (division, region, or district).

Preparation Work

(1) Scheduling the audit - Once the vendor to be audited has been determined, the vendor should be notified of the desire for an audit. Although the audit should not be unannounced, it should begin as soon as possible after the vendor has been notified. The steps to be taken are as follows:

   (a) Determine who should make contact with the vendor. It is best to have a person from the appropriate operating group make the initial contact; however, if agreed to by management, the audit organization may make the initial contact.
   (b) Once the initial contact has been made, the audit group should contact the vendor and discuss the following:
      (i) A date for conducting the audit,
      (ii) The location at which the audit will take place, and

(iii) The time period to be audited so the vendor can ensure the appropriate records will be available.

(c) Discuss the nature of the vendor's business with the appropriate company personnel and determine whether there are any specific concerns.

(d) Once the above has been determined, an audit confirmation letter summarizing this information should be sent to the vendor, signed by either a representative of the operating group or the auditing organization.

Once the above has been completed, the next step is to determine the scope of the audit.

(2) Determining the scope of the audit - The first item to be determined is the time period to be audited. One approach is to obtain the listing of charges from the vendor for the prior 12-month period and calculate the charges by month. Some companies are able to provide the information below in an electronic format. However, if they are unable to, a sample can then be created by:

(a) Selecting the three highest consecutive months or any other combination of months,

(b) Selecting the highest monthly dollar amounts,

(c) Sorting the 12-month period by invoice amount, with the larger dollar invoices selected.

Once the sample is selected, the next step is to develop lead schedules for use in testing the charges.

(3) Developing lead schedules - For the invoices to be tested during the audit, make copies of the invoices and all supporting work tickets, timesheets, etc., and record the invoice information in an electronic spreadsheet so the data can be sorted, summed, and analyzed for use in identifying potential duplicates, for comparison to the rate schedule, and for verifying the accuracy of the invoice calculations. The data to be recorded should include:

(a) Invoice number and date,
(b) Lease, property, project or AFE reference,
(c) Work ticket number,
(d) Labor hours, rates, and dates worked,
(e) Employee name and job function or job title,
(f) Equipment hours, rates, and description,
(g) Material rates, descriptions, and quantity,
(h) Third-party charges (e.g., subcontractor),
(i) Mark-ups, overhead fees, and/or taxes.

(4) Other preparation steps

(a) Obtain the contract, purchase agreements, and any amendments,

(b) Obtain rate schedules or price lists,
(c) Obtain certificates of insurance,
(d) Obtain a listing of company employees interacting with this vendor; ensure the job function of each person is included,
(e) Obtain and review any past audit reports, if available,
(f) Run a business inquiry on the vendor,
(g) Review the contract award process for this vendor; determine how and why the vendor was selected and review any competitive bid files,
(h) Obtain a list of vendor employees or a vendor organizational chart.

Audit Testing/Field Work
Audit testing can be divided into two primary sections: (1) verifying the goods and services received comply with the terms of the contract and (2) verifying there is a proper business relationship between the vendor and the company receiving the goods and services to ensure compliance with the company's business ethics policies.

(1) Verification of goods and services received

(a) Verify the goods or services provided meet the specifications as outlined in the contract.
(b) Verify the rates charged for labor, equipment, and materials agree with the rates per the contract. The lead schedules developed during the preparation stage should aid in this analysis.
(c) Verify discounts, allowances, and rebates have been properly applied.
(d) Verify sales tax calculations.
(e) Verify labor hours charged agree with payroll records.
  (i) Trace the labor hours by vendor employee, as recorded in the lead schedules, to the vendor's employee timesheet and record any instances in which the hours invoiced exceed the vendor employee's labor timesheet.
  (ii) Trace the timesheet hours to the payroll register.
  (iii) On a sample basis, trace net pay from the payroll register to canceled payroll checks.
  (iv) Verify time charged is not also charged to other companies. One method is to compare all vendor invoices for one month to the supporting employee time records. Another option would be to contact other companies that have activity in the same area and also do business with the vendor. If the other company is willing to provide such information, a comparison of dates and labor charges would ensure the two companies are not charged for the same service and employees on the same date.
  (v) Verify vendor employees are not paid in cash and that the vendor is not avoiding proper reporting of payroll taxes. Also consider comparing FICA and withholding tax totals on the vendor payroll register to quarterly Federal payroll tax Form 941 (Employer's Quarterly Federal Tax Return), or equivalent.

(f) Verify the invoices were properly supported with work tickets, etc., and these tickets and invoices were signed by company employees to verify receipt of the goods or services. Also verify the invoices were properly approved.
(g) Verify third-party charges are supported by an invoice from the third party and any mark-up to the cost is in accordance with the terms of the contract.
(h) Verify credits were received for any items returned to the vendor as surplus or scrap material and for goods and services which were included in a fixed price contract but which were not required.
(i) Verify appropriate insurance coverage is maintained.
(j) Verify regulatory requirements are met.

It is noted that many detailed audit steps could be provided for the many types of contracts in the oil and gas industry. However, instead of providing a list of such potential audit steps, it is best for each auditor to review each individual contract being audited and to develop the specific detailed audit steps required to ensure compliance with the terms of that contract.

(2) Review of business relationship to evaluate business ethics

(a) Review the vendor's provision of gifts and entertainment. The types of gifts and entertainment to be aware of include:
  (i) Recreational assets (hunting/fishing leases, cabins, trailers, condominiums, planes, and boats),
  (ii) Club memberships (golf, hunting, tennis, skiing, sailing, flying, etc.),
  (iii) Tickets for sporting or theatrical events,
  (iv) Travel,
  (v) Sponsorships (athletic teams, entry fees),
  (vi) Promotional items (caps, shirts, pens, etc.),
  (vii) Holiday gifts (meat, liquor, sporting equipment, etc.).

In order to identify whether any of the above items were provided to company employees, examine the vendor's accounts payable records, cash disbursements journal, checkbooks, bank statements, canceled checks, expense reports, etc. Any gifts or entertainment provided to company employees should be recorded and then analyzed in conjunction with the company's own ethics and gifts and entertainment policies. Also, review the vendor's chart of accounts and general ledger records to identify accounts in which there is a reasonable expectation the account would include gifts and entertainment. Accounts of particular interest include Miscellaneous Expense, Promotional Expense, Advertising Expense, and Entertainment Expense.
(b) Review dealings between the vendor and company employees with regard to:

(i) Current or previous employment of company employees or relatives,
(ii) Loans of money, equipment, or labor from the vendor to company employees, and/or relatives, and vice versa,
(iii) Problems affecting the business relationship with the company.

(c) Other vendors in the same geographical area that provide similar services may be contacted regarding their attitude toward competitors and their own attempts to secure the company's business.

(d) The last item to remember during fieldwork is to properly document all exceptions. Ensure copies of all vendor records are made to support any exceptions. Also, if there is any suspicion of fraud or business ethics violations, immediately involve your company's security and/or business ethics organizations and ensure such potential findings are kept confidential until appropriate follow-up with these organizations and company management has taken place.

Reporting the Results of the Audit and Audit Resolution

The audit findings should be discussed with the vendor either during or at the conclusion of the audit. The vendor should also be informed the findings will be reported to the appropriate company management team and that someone from the company will follow up with the vendor if needed. It is noted that findings of a fraudulent or unethical nature should not be communicated to the vendor until follow-up with company management has been completed.

The findings and recommendations should also be discussed with the appropriate company management. Resolution should normally be handled by the organization that requested the audit; however, the auditor should be available to assist in the resolution process if requested by management.

A formal audit report should then be prepared. It should provide a summary of the audit and include the following:

(1) Reason for the audit,
(2) Scope of the audit (period covered and dollars reviewed),
(3) Background information on the vendor/contractor (description of the goods and services provided by the vendor),
(4) Audit findings, recommendations, and management action for resolving the audit findings.

The report should be distributed to the vendor and the appropriate company personnel.

The last step is to ensure the action to be taken by management to resolve any findings is completed. The auditor should contact company management after a reasonable amount of time to ensure appropriate action was taken.

Determining Finding, Development, and Acquisition Costs

ACCOUNTING GUIDELINE 12

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COUNCIL OF PETROLEUM ACCOUNTANTS SOCIETIES

DETERMINING FINDING, DEVELOPMENT, and ACQUISITION COSTS

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COPAS Accounting Guideline 12

DETERMINING FINDING, DEVELOPMENT, and ACQUISITION COSTS

I. INTRODUCTION

Most companies involved in oil and gas exploration, development and production activities have developed measurements which reflect the results of effort and expenditures for adding new reserves to their portfolios. The desire to inform investors about some of these measurements led to many of the disclosures requirements for public companies contained in Financial Accounting Standards Board ("FASB"), Accounting Standards Codification ("ASC") 932 Extractive Activities - Oil and Gas. ASC 932 provides accounting guidance for all oil and gas companies as well as certain required disclosures that are only applicable to public companies. In addition to the information required to be disclosed in Annual Reports to Shareholders and Securities and Exchange Commission ("SEC") Annual Reports on Form 10-K, most companies use various other criteria to evaluate their exploration and development management and programs for internal purposes. This information may be disclosed in Form 10-K filing and press releases (filed on Form 8-K) by public companies and internal reporting for private and public companies. This study focuses on those measurements that are not required to be disclosed to the public and are generally referred to as "finding costs," "finding and development costs," and "finding and acquisition costs."

Private companies may provide different information than public companies as the users of the information differ. For example, private companies may provide internal information to its management that does not follow the specific guidance in ASC 932.

The Council of Petroleum Accountants Societies, Inc. ("COPAS") recognizes that there can be no one standard definition for finding, development, and acquisition ("FD") costs and elements included in its calculation. However, because some measurement of FD costs is so important and so widely used by exploration, development, and production enterprises, a discussion of some of the more prevalent different FD costs alternatives, the methods of their calculation, and their suitability for different kinds of enterprises can be helpful to the financial and accounting personnel charged with developing and interpreting such data.

The general purpose of FD cost calculations is to evaluate the relative efficiency of an entity's efforts compared to the results of those efforts. All FD cost calculations have some common features. They all compute an average cost per equivalent barrel of oil ("BOE") or Mcf of gas ("MCFE") added. Natural gas volumes are generally converted to equivalent barrels based on Btu content relative to a barrel of oil or based on energy value of gas to oil. Oil volumes are converted to equivalent Mcf in a similar manner.

Companies may provide FD cost calculations in the aggregate based on total reserves and costs as well as by project, field, or well. The level of detail is determined by the needs of the user of the information. In our study, we use the total aggregate reserves and costs approach. However, the concepts are also applicable to the more detailed costs determinations.

The first and most fundamental difficulty with all of the alternative FD cost calculations discussed relates to matching expenditures and reserves added in a common time period. It might be theoretically desirable to know the actual expenditures required for each increment of reserve additions; however, expenditures leading to reserve additions may be made over several years preceding the drilling of a well, and many expenditures require allocation between results, leading to reserve additions and unsuccessful results. Because the exact attribution of expenditures to reserve additions would be laborious and difficult to determine, most of the widely used methods employ simplifying assumptions that blur the cause-effect relationship but provide useful information when performed consistently over multiple time periods.

This guidance incorporates accounting guidance from ASC 932 (which incorporates SEC guidance), updated as of June 30, 2011. See also SEC Regulation S-X, Rule 4-10.

Sections II and III discuss the various inputs used in the FD cost calculations. Section IV addresses the various methodologies used to determine FD costs.

II. TYPES OF COSTS INCLUDED

This section summarizes the types of costs included in costs incurred in the financial statements using guidance in ASC 932. As noted in Section I, ASC 932 disclosures apply to public companies. However, private companies usually follow this guidance in determining costs to include in costs incurred. It should be noted that some private companies may choose to follow variations of the guidance in ASC 932. The discussion in this Section II uses the detailed guidance in ASC 932. ASC 932 section information is given to facilitate your review of the types of costs. The full text of ASC 932 can be found at FASB.org.

As discussed in Section I, these costs are then used, with some variations, in the FD costs calculations. ASC 932-360-25-7 through 14 addresses the various types of costs incurred by a company that are included in the costs incurred disclosures under ASC 932-235-50-18. A summary from ASC 932-360 follows.

A. Total Costs Incurred

25-18 All of the following types of costs for the year shall be disclosed (whether those costs are capitalized or charged to expense at the time they are incurred):

a. Property acquisition costs,
b. Exploration costs,
c. Development costs.

As defined in paragraphs ASC 932-360-25-9 and ASC 932-360-25-13, exploration and development costs include depreciation of support equipment and facilities used in those activities and do not include the expenditures to acquire support equipment and facilities.

[Note that capital costs include asset retirement obligations. Also, exploration costs include costs of carrying and retaining undeveloped properties such as delay rentals and ad valorem taxes on properties, as well as geological and geophysical costs.]

B. Acquisition

25-7 Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) shall be capitalized when incurred. They include all of the following:

a. The costs of lease bonuses and options to purchase or lease properties
b. The portion of costs applicable to minerals when land including mineral rights is purchased in fee
c. Brokers' fees
d. Recording fees
e. Legal costs
f. Other costs incurred in acquiring properties.

C. Exploration

25-8 Exploration costs may be incurred both before acquiring the related property, sometimes referred to in part as prospecting costs, referred to as "pre-exploration" under International Financial Reporting Standards ("IFRS") and after acquiring the property.

25-9 All of the following are principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities (see paragraph ASC 932-360-25-16) and other costs of exploration activities:

a. Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, those are sometimes referred to as geological and geophysical costs.
b. Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.
c. Dry hole contributions and bottom hole contributions.
d. Costs of drilling and equipping exploratory wells.
e. Costs of drilling exploratory-type stratigraphic test wells. While the costs of drilling stratigraphic test wells are sometimes considered to be geological and geophysical costs, they are accounted for separately under this Subtopic for reasons explained in paragraphs ASC 932-360-25-17 through 25-18.

25-10 The costs of drilling exploratory wells and the costs of drilling exploratory-type stratigraphic test wells shall be capitalized as part of the entity's uncompleted wells, equipment, and facilities pending determination of whether the well has found proved reserves.

25-11 An entity sometimes conducts geological and geophysical studies and other exploration activities on a property owned by another party, in exchange for which the entity is contractually entitled to receive an interest in the property if proved reserves are found or to be reimbursed by the owner for the geological and geophysical and other costs incurred if proved reserves are not found. In that case, the entity conducting the geological and geophysical studies and other exploration activities shall account for those costs as a receivable when incurred and, if proved reserves are found, they shall become the cost of the proved property acquired.

D. Development

25-12 Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas.

25-13 More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities (see paragraph ASC 932-360-25-16) and other costs of development activities, are costs incurred to:

a. Gain access to and prepare well locations for drilling, including all of the following:
   1. Surveying well locations for the purpose of determining specific development drilling sites
   2. Clearing ground
   3. Draining
   4. Road building
   5. Relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

b. Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as:
   1. The wellhead assembly
   2. Pumping equipment
   3. Tubing
   4. Casing.

c. Acquire, construct, and install production facilities such as:
   1. Lease flow lines
   2. Separators
   3. Treaters
   4. Heaters
   5. Manifolds
   6. Measuring devices
   7. Production storage tanks
   8. Natural gas cycling and processing plants
   9. Utility and waste disposal systems.

d. Provide improved recovery systems.

25-14 Development costs shall be capitalized as part of the cost of an entity's wells and related equipment and facilities. Thus, all costs incurred to drill and equip development wells, development-type stratigraphic test wells, and service wells are development costs and shall be capitalized, whether the well is successful or unsuccessful. Costs of drilling those wells and costs of constructing equipment and facilities shall be included in the entity's uncompleted wells, equipment, and facilities until drilling or construction is completed.

III. TYPES OF RESERVES INCLUDED

A. Proved Reserves Discovered

Proved reserves are those reserves as defined by the FASB and SEC (FASB and SEC are defined in Section I). The Master Glossary in the FASB Codification defines proved reserves as follows (please note that reserve engineers follow this definition in preparing the reserve estimates):

> Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulation before the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether the estimate is a deterministic estimate or probabilistic estimate.

The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time.

The area of the reservoir considered as proved includes all of the following:

> a. The area identified by drilling and limited by fluid contacts, if any,
> b. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establish a lower contact with reasonable certainty.

Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Reserves that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when both of the following occur:

> a. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based.
>
> b. The project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period before

the ending date of the period covered by the reserve report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

For purposes of a finding cost calculation, proved reserves discovered should include the company's net portion of discoveries for the applicable period. The amount of proved reserves included should be the same as those reported under the ASC 932-235 Standard Measure of Oil and Gas ("SMOG") disclosure for "Extensions and Discoveries."

B. Proved Reserves Purchased

Some companies include this item in the reserve calculation along with the associated costs to acquire the reserves in calculating the costs of proved reserves added during the period. The proved reserves purchased should be the same as those reported under the ASC 932-235 SMOG disclosure as "Purchases of Minerals In-Place."

C. Proved Reserve Revisions

Some companies include this item in the reserve calculation to determine the costs of proved reserve additions for the current period. The sum of all proved reserve revisions included should be the same as those reported in the ASC 932-235 SMOG disclosure "Revisions of Previous Estimates."

D. Reserves from Improved Recovery

Companies that strive to measure cost of proved reserves added (vs. found) include this item in the reserve calculation to determine the cost of proved reserve additions for the current period. Improved recovery techniques supplement the natural forces and mechanisms of primary recovery of oil and gas reserves. An example is the application of fluid injection. If reserves from improved recovery are included, the quantity should be the same as the reserves reported in the ASC 932-235 SMOG disclosure "Improved Recovery."

E. Probable Reserves Discovered

Some companies feel that inclusion of only the proved reserves assigned to discoveries understate the company's expectation of total proved reserves that will ultimately result from the discovery and therefore overstate finding costs for the period. Probable reserves are reserve estimates that do not currently meet the FASB/SEC definition of proved reserves but that are expected to be produced from currently defined proved reservoirs sometime in the future. Such projections usually involve risk adjusting and use of internal price forecasts. Note: the SEC allows companies to disclose probable reserves along with the key assumptions.

IV. METHODOLOGIES

There are various methodologies used by companies in reporting FD costs with variations in the types of costs as well as the reserves included in the calculation. See a discussion of the types of costs and reserves included in the methodologies in Sections II and III. A summary of the more prevalent methodologies is presented below.

A. Basic FD Costs
Total capital costs incurred are divided by total proved reserve additions.

$$\frac{\text{Current Year Costs Incurred}}{\text{Proved Reserve Additions (BOE or MCFE)}}$$

Capital costs incurred and proved reserve additions should agree with the information disclosed in the financial statements under ASC 932-235.

Proved reserve additions would include proved reserves added through discoveries, extensions, infill drilling, acquisitions, and revisions of pricing and previous estimates.

B. Exclude Certain Current Year Acquisition Costs
Many companies elect to exclude current year acquisition costs from their costs incurred in the calculation of FD costs. This variation focuses the calculation on the reserves added through exploration and development activities rather than acquisitions of properties.

1. Exclude Proved Property Acquisitions
A company may choose to exclude proved property acquisitions from their current year costs incurred used in the FD cost calculation and therefore focus on reserves added through exploration and development activities. In this case, companies should be careful to also exclude the associated purchase of reserves from the calculation. Including purchased reserves without the associated costs will give a skewed view of this FD cost calculation. This calculation would include total current year costs incurred less current year proved property acquisition costs, divided by reserve additions excluding purchases, as follows:

$$\frac{\text{(Current Year Costs Incurred - Proved Property Acquisitions)}}{\text{(Current Year Reserve Additions - Purchases)}}$$

This concept and formula also applies to any divestitures during the year, should a company wish to exclude them. Any current year costs related to the reserves that were sold should be subtracted along with the associated sales of reserves from the calculation of the change in reserves.

2. Exclude Unproved Property Acquisitions
In the methodologies discussed earlier, unproved property acquisition costs are included in determining FD costs. Under this method of determining FD costs, the total amount expended to acquire unproved leases is included in the FD costs calculation in the year the leases are acquired. The principal advantage of this method is the information is usually readily available and does not require an excessive amount of time to determine. The disadvantage of this method, however, is that it does not match the cost of a lease to the year in which oil and gas reserves are discovered or the year final determination is made on the lease to incur (or forgo) other costs. Although this method does not match the actual cost incurred to the year the determination is made, it is an acceptable alternative where the annual expenditures for leasehold acquisitions are relatively even.

Some companies exclude purchases of unproved properties in the FD costs calculation because these unproved property costs may not have resulted in additional oil and gas reserves in the current year. Many companies believe this methodology provides a better "match" between the FD costs and the addition of the related reserves. Excluding unproved property acquisitions from the costs incurred requires no modification of reserve additions used in the calculation. The formula excluding only unproved property costs is as follows:

$$\frac{\text{(Current Year Costs Incurred - Unproved Property Acquisitions)}}{\text{Current Year Reserve Additions}}$$

3. Exclude All Acquisitions

The calculation can be modified to exclude all acquisitions, proved and unproved, with an adjustment to exclude purchased reserves as well. This calculation of FD costs focuses only on the cost of reserves internally developed through the drill bit.

C. Exclude Current Year Costs Incurred for Unsuccessful Exploration

Many companies exclude the costs of unsuccessful exploratory costs in determining FD costs. Unsuccessful exploration costs do not result in related reserves additions; therefore, excluding these costs from the FD costs calculation results in a metric that relates only to reserve additions. Exploratory costs are incurred to discover new proved reserves whereas development costs are incurred to gain access to or produce proved reserves. Though there are development wells which prove to be unsuccessful, there is a much greater chance of unsuccessful drilling in exploration areas. Exploration areas have a higher uncertainty as to how much, or even if, reserves will be found. Therefore, because of this higher uncertainty, excluding unsuccessful exploration costs is understandable in that such costs did not add any value to the reserve base. Though dry development wells do not add any value to the reserve base, they are much more infrequent. Costs of dry development wells are usually included in this methodology because usually proved undeveloped reserves have been included in prior years and would be a negative revision in the current year's reserve additions.

The calculation excluding unsuccessful exploration costs is as follows:

$$\frac{\text{(Current Year Costs Incurred - Unsuccessful Exploration Costs)}}{\text{Current Year Reserve Additions}}$$

D. Include Change in Future Development Costs

Proved undeveloped reserves are included in total reserve volumes and values for a company. In order to gain access to these reserves, a company must incur costs in the future. Some companies choose to include the estimate of future development costs associated with these undeveloped reserves as part of their FD costs calculation. In determining FD costs, a company includes only reserve additions in the calculation; therefore, only the change in future development costs should be added to the current year costs incurred to arrive at a total cost for both developed and undeveloped properties. This change in future development costs would be calculated as the prior year's estimate of future development costs (per the reserve report) less the current year's estimate of future development costs (per the reserve report). As new proved undeveloped reserves are added, new future development costs are estimated and included in this calculation. Only the changes in both reserve estimates and future development costs are included. This matches the estimated costs in the time period the property's reserves are included as proved undeveloped reserves. Subsequent year changes in estimates for either reserve volumes or future development costs will be included in the FD costs calculation in future years. The calculation including the change in future development costs is as follows:

$$\frac{\text{(Current Year Costs Incurred} \pm \text{Change in Future Development Costs)}}{\text{Current Year Reserve Additions}}$$

E. Base Reserve Adjustments

In addition to adjusting the costs incurred in the various FD costs calculations, many companies choose to adjust the reserve additions used in the calculation. Each of these variations can be made alone, or in combination with other reserve base adjustments. Also, each of these adjustments can be made in combination with the adjustments made to the costs incurred included in the FD costs calculation discussed earlier. Because the reserve portion of this calculation begins with the standard reserve additions used in the ASC 932 (SMOG) calculation, there is useful information that can be derived from the SMOG disclosure and used in the FD costs calculation. Each adjustment to reserve additions results in a different FD cost metric.

1. Current Year Reserve Additions Less Price Revisions

Companies may choose to exclude the impact on reserve additions from commodity price changes. By excluding the price effects on reserve additions in the FD costs calculation, the FD cost metric reflects reserve growth regardless of price volatility. In this calculation, the price revisions in the calculation should agree with "Price Changes" in the SMOG disclosure.

$$\frac{\text{Current Year Costs Incurred}}{\text{(Current Year Reserve Additions - Price Revisions)}}$$

2. Current Year Reserve Additions Less Revisions in Estimates

Companies may choose to exclude revisions to reserves sometimes referred to as performance revisions. Wells may perform better or worse than initially expected and therefore future reserve estimates may increase or decrease based on new information. By excluding revisions in estimates in the FD costs calculations, the FD cost metric reflects the costs of adding reserves for the period and is not impacted by prior period quantity revisions which may not have related current costs. In this calculation, the revisions in estimates in the calculation should agree with "Revision in Estimates" in the SMOG disclosures.

$$\frac{\text{Current Year Costs Incurred}}{\text{(Current Year Reserve Additions - Revision in Estimates)}}$$

3. Current Year Reserve Additions Less Price Revisions and Revisions in Estimates

By combining the adjustments for both price and quantity estimates, a company's FD cost metric reflects the costs of adding reserves for the period without the impact of commodity price volatility or prior period quantity revisions.

$$\frac{\text{Current Year Costs Incurred}}{\text{(Current Year Reserve Additions - Price and Estimate Revisions)}}$$

4. Current Year Reserve Additions Less Proved Undeveloped Reserve Additions

Companies may choose to exclude the proved undeveloped reserve additions so that the FD cost metric will reflect only the costs associated with adding proved developed reserves. No change is required in the costs incurred to be included in the FD costs calculation. A company would not use this method and the method discussed in D above.

$$\frac{\text{Current Year Costs Incurred}}{\text{Current Year Proved Developed Reserve Additions}}$$

F. Include Probable Reserves

Under SEC regulations, it is permissible to include certain probable reserves in reserve disclosures if appropriate disclosures are included. Companies may choose to include probable reserves in their FD costs calculation to obtain a more in-depth metric of the cost of finding all reserves. It is important to note however that if probable reserves are included, unproved leasehold acquisition costs should also be included in the FD costs calculation.

$$\frac{\text{Current Year Costs Incurred}}{\text{(Current Year Reserve Additions + Probable Reserve Additions)}}$$

V. SUMMARY

It is obvious from the above discussion that many more alternatives and methods of measuring the cost of finding, developing, or adding reserves could be used. One method does not seem to be more "correct" than another. The important point to be made is that any method used should clearly identify what is being measured and should be consistently applied from year to year.

Although some companies present a finding and development cost figure in their annual reports on Form 10-K or Form 40-F or in their press releases on Form 8-K, most companies do not publicly disclose their finding cost results. A reason companies do not disclose this information probably relates to a fear that management may be accused of publishing misleading information because the results can vary so widely depending on the method employed.

The information available to the public does not enable accumulating and tracking at an individual well/property/field level and is limited in many other aspects. For this and other reasons, individual companies will and should continue to use whatever types of internal measures that best fit their operations and management styles. In this manner, individual companies are not limited to public information, but can develop more sophisticated measures to more fully and accurately assess their performance.

As previously stated, it is not the intent of this paper to develop a single recommended method for measuring finding, development and acquisition costs, but, hopefully it will provide some insights to companies in the industry to help them refine or improve the value of their own FD calculation.

Exhibit A
COPAS Accounting Guideline 12
Finding, Development, and Acquisition Costs
Section IV
Examples of Methodologies
(in thousands)

Assumptions		Current Year Data
Acquisition Costs:		
Proved Properties	A	$85,000
Unproved Properties	B	10,000
Disposition Costs:		
Proved Properties	C	(12,500)
Unproved Properties	D	(30,000)
Exploration Costs		
Successful	E	50,000
Unsuccessful	F	7,500
Development Costs	G	250,000
Asset Retirement Obligation	H	1,500
Current Year Costs Incurred	I	361,500
Change in future development costs	J	6,000
Total Finding, Development and Acquisition Costs	K	$367,500
Proved Developed Reserve Additions (MMCFE):		
Extensions and discoveries	L	325,000
Purchases, net of dispositions	M	55,000
Total Proved Developed Reserve before Revisions	N	380,000
Revisions in estimates	O	(35,000)
Price revisions	P	(128,000)
Total Proved Developed Reserves Additions	Q	217,000
Proved Undeveloped Additions	R	85,000
Total Proved Reserve Additions	S	302,000
Probable Reserves Additions	T	136,000
Total Reserve Additions	U	438,000

Finding, Development and Acquisition (FD) Costs			Methodology Reference
FD Costs, Base Case	I/S	$ 1.20	A
FD Costs, excluding Acquisitions and Dispositions	(I-A-C)/(S-M)	$ 1.17	B(1)
FD Costs, excluding Unproved acquisitions/dispositions	(I- B-D)/S	$ 1.25	B(2)
FD Costs, excluding unsuccessful exploration	(I-F)/S	$ 1.07	C
FD Costs, including change in future development costs	K/S	$ 1.22	D
FD Costs, excluding price revisions	I/(S-P)	$ 2.08	E(1)
FD Costs, excluding performance revisions	I/(S-O)	$ 1.07	E(2)*
FD Costs, excluding performance and price revisions	I/(S-O-P)	$ 0.78	E(3)*
FD Costs, Proved developed only	I/Q	$ 1.67	E(4)*
FD Costs, including Probable reserves	I/U	$ 0.83	F**

* Could use this denominator with the numerators in B(1), B(2), C, and D

** Could use this denominator with the numerators in B(1), C, and D

Accounting for Farmouts/Farm-ins, Net Profits Interests and Carried Interests

ACCOUNTING GUIDELINE 13

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IV. INTRODUCTION

Joint development of oil and gas properties is conducted under several types of agreements. This accounting guideline explains the most common types of arrangements that involve Payout accounting and some of the contractual provisions that affect Payout. This document also provides guidelines for the suggested content of the accounting provisions as well as the accounting and cost reporting normally required for these operations.

Accounting procedures are an essential part of these agreements, and the accounting must meet the requirements of the agreements. The actual agreements and the accounting procedures governing an operation are required to determine the proper accounting and reporting procedures.

Some agreements are structured as tax partnerships due to the circumstances involved. It is not the intent of this guideline to discuss the various ramifications of tax partnerships. Tax questions or problems encountered should be reviewed with appropriate tax counsel.

In the simplest terms, Payout is the condition at which the revenues to a given interest in a well is equal to all land, acquisition, drilling, completing, and operating costs allocated to that interest. If there is one Working Interest Owner ("WIO"), one royalty owner, and one well it is a simple calculation of the sum of leasehold + intangibles + tangibles + operating expenses - gross revenues + production taxes + royalty burdens.

Unfortunately, little in the oil and gas industry is that simple. Payout calculations are complicated by the governing agreement, the applicable accounting procedure, number of parties involved, possible penalties, and general circumstances related to cost sharing, revenue receipts, and royalty payments. It is important to consider all these factors when calculating Payout.

The simple calculation noted above can be used only for determining a general economic Payout of the well or project. When determining when a particular ownership interest changes because of Payout, costs and revenues must be allocated to the particular party involved in order to determine that party's Payout date. Any other method results in inequities to the parties not subject to that particular Payout.

This document attempts to provide guidance on the complexities involved in calculating the most accurate Payout, based on complex circumstances. Please refer to the governing agreements when determining the Payout status of any given well or project.

V. FARMOUTS/FARM-INS

A. General

There can be numerous variations to the terms and conditions contained in a Farmout agreement. A common arrangement is one in which the Farmor retains an economic interest in the assigned acreage. The interest retained in a tract in which the working interest ("WI") is conveyed is usually in the form of a Reversionary Overriding Royalty Interest until the Payout of the designated operation occurs.

B. Provisions

The following items may be included in Farmout agreements containing a Payout provision:

1. The Farmee shall keep an accurate record of all charges and credits connected with revenue and expenditures for each individual well as provided for in the Farmout agreement.
2. Audit Rights should be described in detail.
3. The method of calculating Payout should be defined.
4. The Farmee shall furnish the Farmor a Payout Statement within a specified period of time after the period for which the computations are made.
5. The Farmee should formally notify the Farmor of the Payout date within a specified time. If a conversion option is exercised, the Farmor will formally notify the Farmee of such election within a specified time.
6. The effective date of conversion to a WI should be specified. Two of the more common dates used are the first day of the month following the month during which the Payout occurs, or 7 a.m. local time on the first day following the day on which the well or project paid out. If the latter method is used, expenditures and revenues should be allocated on a daily basis for the month in which Payout occurred.

Note: This is not intended to be an all-inclusive list. Readers should consult with appropriate financial and legal representatives.

C. Sample Payout Provisions

As an example, assume that the Payout agreement defines Payout as follows:

> At Payout, the Farmor shall have the option to convert its Overriding Royalty to a ___% leasehold working interest (to be decreased proportionately if the leasehold interest to be assigned hereunder covers less than the entire and undivided interest in the described lands and/or the proration unit assigned to said well) together with a like interest in the well. This should include all casing, surface equipment, and all personal property used in connection therewith at such time as the actual net proceeds received, as hereinafter defined, from the sale of all oil and/or gas produced from the well, or credited by reason of transferred allowable or unit allocation or any other means, attributable to the interest assigned hereunder, equals one hundred percent (100%) of the cost and expense, both tangible and intangible,

of drilling, testing, and completing said well for production and of operating said well to the point of recouping said 100% of such costs and expenses attributable to the interest assigned hereunder.

The net proceeds are defined as the total proceeds received from production credited or allocated to the well after deducting transportation costs, severance, production, and other taxes payable on production, all royalties or shut in gas royalties, and overriding royalties paid out of production and presently in effect as of the effective date of this agreement. All costs and expenses shall be determined in accordance with the attached accounting procedure.

If this were a project Payout rather than individual well Payout, the provision would need to be modified accordingly.

D. Payout Calculation

1. Assigned Interest

Some Farmout agreements may cover multiple wells and require a separate Payout calculation and separate election for each well. In other cases, the Payout account will consist of costs for a project, which may include more than one well and/or associated facilities. The parties need to specify in the Farmout agreement whether Payout will be calculated on a well or a project basis. If the Farmee is carrying less than 100% of the WI during the Payout phase, Payout should be calculated on the Farmee's working interest.

Example 1: Payout Calculation

Facts:

Party "A"

- Farms out 40-acre spacing to Party "B"
- Retains 1/16 Overriding Royalty interest until Payout

Party "B"

- Forms a 160-acre spacing unit, of which the assigned 40 acres from Party "A" are a part.
- 1/8th royalty burden in the entire 160-acre unit.

Payout will occur after Party "B" recovers proceeds from production (after deducting all applicable taxes, royalties and overriding royalties as defined by the Farmout agreement) equal to 100% of the tangible and intangible well costs and operating expenses attributable to the 40-acre tract.

Table 1: Revenue and Costs for Payout Calculation

Costs/Revenues	First Six Months	Second Six Months
Tangible Well Costs	$250,000	$50,000
Intangible Well Costs	550,000	50,000
Operating Expenses	100,000	100,000
Gross Revenues	850,000	850,000
Production Taxes*	195,000	195,000

*Assume same tax rate applies to all ownerships and corresponding acreages.

Figure 1: Ownership 160-acre Spacing Unit Before Farmout

Tract "A" (40 acres)
* Party "A" WIO
* 1/8th Royalty

Tract "B" (120 acres)
* Party "B" WIO
* 1/8th Royalty

Figure 2: Ownership 160-acre Spacing Unit After Farmout

Tract "A" (40 acres)
* Party "B" WIO
* 1/8th Royalty
* 1/16th ORRI "A"

Tract "B" (120 acres)
* Party "B" WIO
* 1/8th Royalty

Tangible well costs were $250,000 and intangible costs were $550,000. Total operating expenses for the first six-month period were $100,000. Gross revenues and taxes for the same period totaled $850,000 and $195,000, respectively. Assume the same tax rates apply to all ownerships and their corresponding acreage.

The second six-month period had tangible well costs of $50,000, intangible well costs of $50,000, and the same operating expenses, revenue, and taxes as the first six-month period. (All above figures are stated on a gross basis.)

Table 2: Payout Calculations

	Improper Calculation Gross Payout 160-acre Unit	Proper Calculation Net Payout 40-acre Unit
First Six Months	100%	40/160 or 25%
Prior Balance to Payout	$ 0	$ 0
Well Costs - Tangible and Intangible	800,000	200,000
Operating Expenses	100,000	25,000
Total Expenditures	900,000	225,000
Deduct Gross Revenues	(850,000)	(212,500)
Less Tax	195,000	48,750
Less Royalty (1/8th of gross, net tax)	81,875	20,469
Less Overriding Royalty (1/16 x 25%) ($850M-$195M)	10,234	10,234
Net Revenue	(562,891)	(133,047)
Current Period Transactions	337,109	91,953
Balance to Payout	$337,109	$91,953

Second Six Months	100%	40/160 or 25%
Prior Balance to Payout	$337,109	$91,953
Well Costs - Tangible and Intangible	100,000	25,000
Operating Expenses	100,000	25,000
Total Expenditures	200,000	50,000
Deduct Gross Revenues	(850,000)	(212,500)
Less Tax	195,000	48,750
Less Royalty (1/8th of gross, net tax)	81,875	20,469
Less Overriding Royalty (1/16 x 25%) ($850M-$195M)	10,234	10,234
Net Revenue	(562,891)	(133,047)
Current Period Transactions	(362,891)	(83,047)
Balance to Payout	$ (25,782)	$8,906

It is important to understand why Farmouts are structured so that Payout is normally calculated only on the interest assigned rather than for the entire well. In the example, the ratio of amounts used to compute a well gross Payout versus a net Payout would be 100% to 25% for all items except the 1/16th Overriding Royalty burden, which is borne only by the assigned interest. Since the remaining 75% working interest has no Overriding Royalty burden, the same $10,234 amount is included in both computations. As indicated in the computation above, this would cause Payout to occur prematurely if the well (gross) Payout calculation is used instead of the assigned interest (net) Payout.

Conversely if the assigned interest is burdened by a smaller Overriding Royalty or lease royalty than the rest of the leases or interest contributed to the well, the use of the well (gross) Payout calculations will result in a delayed Payout.

An alternative to the above calculation would be to use the well total costs and revenues but determine a Net Revenue Interest ("NRI") based on the assigned acreage. In other words, the revenue net of royalty and Overriding Royalty would be calculated on a well basis as in the example below.

Example 2: Well Level Payout Calculation
Table 3: Well Level Payout Alternative Calculations

First Six Months of Revenue	Amount
Gross Revenue	$850,000
Less Tax	195,000
Revenue Net of Tax	655,000
Multiplied by NRI 100% less royalty decimal less Overriding Royalty decimal for assigned interest. 1.00-.125-.0625 = .8125	
Net Revenue (first six months)	$532,188

This alternative allows the use of well level revenues and costs, while arriving at Payout at the same time as the method in Example 1, which uses tract level revenue and cost data.

2. Multistage Payout - Assigned Interest

On occasion, there may be multiple parties taking a Farmout of an interest; i.e., multiple Farmees. Another situation that can arise is when there are multiple Farmors. Interests will pay out at different times for parties who maintain different Overriding Royalties. Payout must be calculated separately for each assigned interest.

Example 3: Multi-Party Payout Calculation

Facts:

- 160-Acre Unit
- Party "B" receives 40-acre Farm-in from Party "A"
- 1/16th Overriding Royalty with option to convert to WI at Payout.
- Party "B" receives 40-acre Farm-in from Party "C"
- 1/8th Overriding Royalty, with option to convert to WI at Payout.
- Party "B" owns remaining 80 acres
- Costs
- $250M Tangible
- $550M Intangible
- $100M Operating Expense
- Revenue - $850M

- Taxes - $195M
- Royalty for all tracts 1/8th

Payout occurs when "B" recovers proceeds from production (net of applicable taxes and royalties as defined by the Farmout agreement) equal to 100% of the tangible and intangible well costs and operating expenses attributable to both 40-acre tracts received from "A" and "C."

Table 4: Revenue and Costs for Multistage Payout

Costs/Revenues	Amount
Tangible Well Costs	$250,000
Intangible Well Costs	550,000
Operating Expense	100,000
Gross Revenues	850,000
Production Taxes*	195,000

*Assume same tax rate applies to all ownerships and corresponding acreages.

Figure 3: Ownership 160-acre Spacing Unit Before Farmout

<table>
<tr><td>Tract “A” (40 acres)
* Party “A” WIO
* 1/8th Royalty</td><td rowspan="2">Tract “B” (80 acres)
* Party “B” WIO
* 1/8th Royalty</td></tr>
<tr><td>Tract “C” (40 acres)
* Party “C” WIO
* 1/8th Royalty</td></tr>
</table>

Figure 4: Ownership 160-acre Spacing Unit After Farmout

<table>
<tr><td>Tract “A” (40 acres)
* Party “B” WIO
* 1/8th Royalty
* 1/16th ORRI “A’</td><td rowspan="2">Tract “B” (80 acres)
* Party “B” WIO
* 1/8th Royalty</td></tr>
<tr><td>Tract “C” (40 acres)
* Party “B” WIO
* 1/8th Royalty
* 1/8th ORRI “C”</td></tr>
</table>

Table 5: Multistage Payout Calculations

Payout	"A" 40 Acres with 1/16th Override	"C" 40 Acres with 1/8th Override
Prior Balance to Payout	$ 0	$ 0
Total expenditures from example 1: 900M x 25%	225,000	225,000
Less net revenue from example 1: ($212,500 - $48,750 - $20,469)	(143,281)	(143,281)
Charge for Overriding Royalty 1/16 x 25% ($850M - $195M)	10,234	0
1/8 x 25% ($850M - $195M)		20,468
Net Revenue	(133,047)	(122,813)
Current Period Transaction	91,953	102,187
Balance to Payout	$91,953	$102,187

Calculation of a single Payout based on the total assigned interest received by "B" would result in Payout of "A" and "C" occurring at the same time but would not be equitable to "A." Payout for "A" should occur sooner than for "C" since the assigned interest attributable to "A" is burdened by a smaller Overriding Royalty interest.

Note that the alternative NRI calculation on a well basis described in Example 2 could also apply to Example 3. Even in the alternative two Payouts would be calculated, one for "A" and one for "C," the NRI decimal for "A" would be the same as Example 1 (.8125). The NRI for "C" would be (1.00 - .125 royalty - .125 Overriding Royalty = .75).

3. Gas Sales versus Production

The application of gas revenue to the Payout Statement may also complicate the Payout calculation. Whenever different purchasers, different gas sales contracts, and different lease and Farmout agreements are involved in a producing lease or unit, the Farmee must consider these facts when computing Payout.

Payout calculation Example 4 is an example of a Payout Statement that shows multiple purchasers, variable gas prices and a gas-balancing situation.

Example 4: Multistage Payout on a Gas Well Calculation

Facts:

- 160-acre unit
- Party "B" 40-acre Farm-in from Party "A"

- 1/16th Overriding Royalty with 25% WI conversion option.
- Party “D” 40-acre Farm-in from Party “C”
- 1/8th Overriding Royalty with 25% WI conversion option.
- Party “B” owns remaining 80 acres
- Costs
- $250M Tangible
- $550M Intangible
- $10M per month operating expense
- Sales
- Party “B” to Party “B1” at $2/Mcf. 1st 6 months – 150 MMcf. 2nd 6 months–120 MMcf.
- Party “D” to Party “D1” at $3/Mcf. 1st 6 months-0 Mcf, 2nd 6 months-90 MMcf.
- Taxes are $.065/Mcf.
- Royalty for all tracts 1/8th paid on entitlement
- ORRI for all tracts paid on entitlement
- Payout calculated on sales.

Table 6: Revenue and Cost Multistage Payout on Gas Well

Costs/Revenue Description	Amounts
Tangible Well Costs	$250,000
Intangible Well Costs	550,000
Operating Expense	10,000/month
Sales-Party “B” to Purchaser “B1”	Price: $2/Mcf First Six Months: 150 MMcf Second Six Months: 120 MMcf
Sales-Party “D” to Purchaser “D1”	Price: $3/Mcf First Six Months: 0 MMcf Second Six Months: 90 MMcf
Production Taxes*	$0.065/Mcf

*Assume same tax rate applies to all ownerships and corresponding acreages.

Figure 5: Ownership Before Farmout

Tract “A” (40 acres) * Party “A” WIO * 1/8th Royalty	Tract “B” (80 acres) * Party “B” WIO * 1/8th Royalty
Tract “C” (40 acres) * Party “C” WIO * 1/8th Royalty	

Figure 6: Ownership After Farmout

Tract “A” (40 acres) * Party “B” WIO * 1/8th Royalty * 1/16th ORRI “A”	Tract “B” (80 Acres) * Party “B” WIO * 1/8th Royalty
Tract “C” (40 acres) * Party “D” WIO * 1/8th Royalty * 1/8th ORRI “C”	

Table 7: Multistage Payout on Gas Well Calculations

Payout	"A" Tract 40 Acres 1/16th ORRI $2/Mcf	"C" Tract 40 Acres 1/8th ORRI $3/Mcf
Prior Balance to Payout	$0	$0
Well Costs ($800M x 40/160 acres)	200,000	200,000
Operating Expenses (12 x $10 M x 40/160 acres)	30,000	30,000
Total Expenditures	230,000	230,000
Revenue First Six Months 150 MMcf. B: (150 MMcf x $2 x 40/120)	(100,000)	0
Less: Production Taxes B: (150 MMcf x 0.065 x 40/120)	3,250	0
Royalty B: 1/8 x150 MMcf x ($2 less 0.065) x 40/160	9,070	0
D: 1/8 x 150 MMcf x ($3 less 0.065) x 40/160	0	13,758
ORRI B: 1/16 x 150 MMcf x ($2 less 0.065) x 40/160	4,535	0
D: 1/8 x 150 MMcf x ($3 less 0.065) x 40/160	0	13,758
Revenue Second Six Months – 210 MMcf B: 120 MMcf x $2 x 40/120	(80,000)	0
D: 90 MMcf x $3 x 40/40	0	(270,000)
Less: Production Taxes B: (120 MMcf x 0.065 x 40/120)	2,600	0
D: (90 MMcf x 0.065 x 40/40)	0	850
Royalty B: 1/8 x 210 MMcf x ($2 less 0.065) x 40/160	12,698	0
D: 1/8 x 210 MMcf x ($3 less 0.065) x 40/160	0	19,261
ORRI B: 1/16 x 210 MMcf x ($2 less 0.065) x 40/160	6,349	0
ORRI D: 1/8 x 210 MMcf x ($3 less 0.065) x 40/160	0	19,261
Balance to Payout	$88,502	$31,888

The following will further explain the acreage ratios used to calculate production taxes, royalty, and Overriding Royalty interests. Of the 160-acre spacing unit, Party "B" has 120 acres (40 acres farmed-in from Party "A" plus the 80 acres originally owned by Party "B"). Since production taxes are based on actual sales volumes and Party "B" took all of the sales for the first six months, Party "B" would pay all of the production taxes during this period. The Tract "A" share would be 40/120 or 1/3. For the second six months, the Tract "A" share would be 40/120 (or 1/3) of the total production taxes paid by Party "B." The Tract "C" share would be 40/40 (all) of the total production taxes paid by Party "D." Since royalty and Overriding Royalty are based on Entitlement (or full unit production), Tract "A" and Tract "C" would each be liable for 40/160 (or 1/4) for both time periods.

VI. GAS BALANCING

A. Based on Gas Sales

Below is a more detailed example of a Payout involving multiple gas purchases, variable gas prices and gas balancing in which this example, and subsequent discussion, is directed toward a Farmout situation but would also apply to any situation requiring Payout calculations.

Example 5: Gas Balancing Payout Calculation

Facts:

- 160-acre Unit
- Party “B” 40-acre Farm-in from Party “A”
- 1/16th Overriding Royalty with 25% WI conversion option
- Party “D” 40-acre Farm-in from Party “C”
- 1/8th Overriding Royalty with 25% WI conversion option
- Party “B” owns remaining 80 acres
- Costs
- $250 M tangible
- $550 M intangible
- $10 M per month operating expense
- Sales
- Party “B” to Party “B1” at $2/Mcf – First Six Months - 150 MMcf, Second Six Months - 66 MMcf, Second and Third Years - 300 MMcf
- Party “D” to Party “D1” at $3/Mcf - First Six Months - 0 Mcf, Second Six Months - 98 MMcf, Second and Third Years - 160 MMcf
- Party “C” to Party “D1” at $3/Mcf, Second and Third years - 30 MMcf
- Taxes are $0.065/Mcf
- Royalty for all tracts 1/8th, paid on Entitlements
- ORRI paid on Entitlements
- Payout calculated on sales

- **Table 8: Revenue and Cost Multistage Payout on Gas Well**

Costs/Revenues Description	Amounts
Tangible Well Costs	$250,000
Intangible Well Costs	550,000
Operating Expense	10,000/month
Sales-Party “B” to Purchaser “B1”	Price: $2/Mcf First Six Months: 150 MMcf Second Six Months: 66 MMcf Years Two-Three: 300 MMcf
Sales-Party “D” to Purchaser “D1”	Price: $3/Mcf First Six Months: 0 MMcf Second Six Months: 98 MMcf Years Two-Three: 160 MMcf
Sales-Party “C” to Purchaser “D1”	Price: $3/Mcf Years Two-Three: 30 MMcf
Production Taxes*	$0.065/Mcf

*Assume same tax rate applies to all ownerships and corresponding acreages.

Figure 7: 160-acre Ownership Before Farmout

Tract “A” (40 acres) * Party “A” WIO * 1/8th Royalty	Tract “B” (80 acres) * Party “B” WIO * 1/8th Royalty
Tract “C” (40 acres) * Party “C” WIO * 1/8th Royalty	

Figure 8: 160-acre Ownership After Farmout

Tract “A” (40 acres) * Party “B” WIO * 1/8th Royalty * 1/16th ORRI - “A”	Tract “B” (80 acres) * Party “B” WIO * 1/8th Royalty
Tract “C” (40 acres) * Party “D” WIO * 1/8th Royalty * 1/8th ORRI - “C”	

Table 9A: Multistage Payout with Gas Balancing (1st Year)

Payout (First Year)	"A" Tract 40 Acres 1/16th ORRI $2/Mcf Price	"C" Tract 40 Acres 1/8th ORRI $3/Mcf Price
Prior Balance to Payout	$0	$0
Well Costs ($800M x 40/160 acres)	200,000	200,000
Operating Expenses (12 x $10M x 40/160 acres)	30,000	30,000
Total Expenditures	230,000	230,000
Revenue First Six Months 150 MMcf B: (150 MMcf x $2 x 40/120)	(100,000)	0
Less: Production Taxes B: (150 MMcf x 0.065 x 40/120)	3,250	0
Royalty B: 1/8 x 150 MMcf x ($2 less 0.065) x 40/160	9,070	0
D: 1/8 x 150 MMcf x ($3 less 0.065) x 40/160	0	13,758
ORRI B: 1/16 x 150 MMcf x ($2 less 0.065) x 40/160	4,535	0
D: 1/8 x 150 MMcf x ($3 less 0.065) x 40/160	0	13,758
Revenue Second Six Months – 164 MMcf B: 66 MMcf x $2 x 40/120	(44,000)	0
D: 98 MMcf x $3 x 40/40	0	(294,000)
Less: Production Taxes B: (66 MMcf x 0.065 x 40/120)	1,430	0
D: (98 MMcf x 0.065 x 40/40)	0	6,370
Royalty B: 1/8 x 164 MMcf x ($2 less 0.065) x 40/160	9,917	0
D: 1/8 x 164 MMcf x ($3 less 0.065) x 40/160	0	15,042
ORRI B: 1/16 x 164 MMcf x ($2 less 0.065) x 40/160	4,958	0
D: 1/8 x 164 MMcf x ($3 less 0.065) x 40/160	0	15,042
Total Net Revenue	(110,840)	(230,030)
Balance to Payout End of First Year	$119,160	$(30)

Table 9B: Multistage Payout with Gas Balancing (Second and Third Year)

Payout (Second and Third Years)	"A" Tract 40 Acres 1/16th ORRI $2.00/Mcf Price	"C" Tract 18.75% WI for "D" $3.00/Mcf Price	"C" Tract 6.25% WI for "C" $3.00/Mcf Price
Prior Balance to Payout	$119,160	N/A	N/A
Operating Expense 24 x $10M x 40/160	60,000	45,000	15,000
Revenue Second and Third Year B: 300 MMcf @ $2 x 40/120 D: 160 MMcf @ $3 C: 30 MMcf @ $3	 (200,000) 0 0	 0 (480,000) 0	 0 0 (90,000)
Less: Production Taxes B: 300 MMcf x .065 x 40/120 D: 160 MMcf x .065 C: 30 MMcf x .065	 6,500 0 0	 0 10,400 0	 0 0 1,950
Royalty B: 1/8 x 490 MMcf x ($2 - .065) x 40/160 D: 1/8 x 490 MMcf x ($3 - .065) x .1875 C: 1/8 x 490 MMcf x ($3 - .065) x .0625	 29,630 0 0	 0 33,707 0	 0 0 11,236
ORRI B: 1/16 x 490 MMcf x ($2 - .065) x 40/160	 14,815	 0	 0
Net Revenue	(149,055)	(435,893)	(76,814)
Balance to Payout	30,105	N/A	N/A

The following will further explain the acreage ratios used to calculate production taxes, royalty, and ORRI. Of the 160-acre spacing unit, "B" has 120 acres (40 acres farmed-in from "A" plus the 80 originally owned by "B"). Since production taxes are based upon actual sales volumes and "B" took all of the sales for the first six months, "B" would pay all of the production taxes during the period. The Tract "A" share of this would be 40/120, or 1/3. For the second six months, Tract "A" share would be 40/120, or 1/3 of the total production taxes paid by Party "B." The Tract "C" share would be 40/40 (all) of the total production taxes paid by Party "D." Since royalty and Overriding Royalty are based on Entitlement (or full unit production), Tract "A" and Tract "C" would each be liable for 40/160, or 1/4, for both time periods.

The previous example calculates Payout based on production taken (sales) by the parties, rather than their Entitlement shares. Under this example, Tract "C" paid out after one year whereas Tract "A" did not pay out within the life of the well. The next table reflects the gas balancing status for the above example.

Table 10: Calculate Gas Balancing Status

Basis: Mcf	Entitlement	Actual	Over/(Short)	Cumulative Over/(Short)
Party "B"				
First Six Months	112,500	150,000	37,500	37,500
Second Six Months	123,000	66,000	(57,000)	(19,500)
Adjustment at Payout				
Second and Third Years	367,500	300,000	(67,500)	(87,000)
Party "D"				
First Six Months	37,500	0	(37,500)	(37,500)
Second Six Months	41,000	98,000	57,000	19,500
Adjustment at Payout			(4,875)	14,625
Second and Third Years	91,875	160,000	68,125	82,750
Party "C"				
First Six Months				
Second Six Months				
Adjustment at Payout			4,875	4,875
Second and Third Years	30,625	30,000	(625)	4,250

When there are gas imbalances and Payouts are calculated on actual takes, the Farmee's or carrying party's gas imbalance created during Payout must be considered. In the above example, an adjustment was made to transfer 25% of the imbalance from Party "D" to Party "C" because Party "C" backed into 25% of Party "D's" working interest. This adjustment is necessary as Party "D" was overproduced, which caused Payout to occur sooner than it would have if Party "D" had been in balance. Additional sales of 78,000 Mcf, all of which would be taken by Party "B," would be required to get all the parties in balance. If total additional sales were 78,000 Mcf, Party "B" would be entitled to 75% of this amount, or 58,500 Mcf. If party "B" took the entire 78,000 Mcf, Party "B" would be overproduced by 19,500 Mcf for that period and brought into balance on a cumulative basis. At that point, Party "C" would be entitled to 6.25% of remaining production from years two and three or [(490,000 Mcf - 78,000 Mcf) x (.0625)] = 25,750 Mcf.

At depletion, Party "B" is entitled to cash balancing for 87,000 Mcf from Parties "D" (82,750 Mcf) and "C" (4,250 Mcf). The result would be that Party "B" received 87,000 Mcf x ($3 less .065), or $255,345. Since each party paid royalty on Entitlements, the overproduced party did not pay royalty on the overage. Therefore, the overproduced Parties ("D" and "C") should pass 8/8's of the revenue attributable to the imbalance to the underproduced party, as the underproduced party had paid the royalty. One-third of this amount, $85,115, would be applied to the Tract A Payout, causing Payout to occur. Assuming Party "A" elected to, or was deemed to have backed into a working interest, Party "A" would therefore be entitled to a portion of the cash balancing as follows:

Balance beyond Payout	$85,115 - $30,105 = $55,010
Mcf associated with this balance	$55,010 / ($3 less .065) = 18,743 Mcf
ORRI paid beyond Payout	18,743 x ($2 less .065) = $36,268
	$36,268 x 1/16 = $2,266

Refund 100% of ORRI attributable to Mcf in excess of Payout balance and proceeds and receive 25% WI credit for production occurring after Payout.

Net amount due Party "A" from backing into WI after cash settlement:

25% of after Payout Cash Settlement	($55,010 x .25) =	$13,753
Refund after Payout ORRI	($36,268 x 1/16) =	(2,266)
Reduced balance to Payout	($2,266 x .25 WI share) =	567
Net amount due Party "A"		$12,054

To further clarify, consider the example in which the Farmee is significantly underproduced at depletion of the balancing area and Payout occurs at that time. If the Farmee had been in balance all along, then Payout would have occurred sooner and the Farmor would have received revenue prior to the reservoir depletion. Therefore, if the Farmor elected to back into a working interest, it is proper for the Farmor to also back into its proportionate share of Farmee's gas imbalance incurred during the Payout period and the settlement for the under-produced position. If the Farmor did not elect to exercise its option to back into a working interest, the above settlement would not be applicable. In that case, the Farmor would not receive a portion of the cash settlement but may be due an increase in its Overriding Royalty payment, depending on the terms of the Farmout agreement.

Consider another example in which the Farmee is significantly overproduced and Payout occurs at depletion of the balancing area. If Farmee had been in balance all along, Payout would not have occurred. Because depletion occurred at Payout, Farmor did not receive any production and therefore is not liable for cash settlement to the underproduced parties. The Farmee, having received the overproduction would be wholly responsible for the cash settlement.

In summary, if the Farmee is overproduced at the time of Payout (calculated on an actual sales or takes basis) and Farmor converts to a working interest, the Farmor backs into a portion of the overproduced status and becomes liable for volumes taken by it (not the full overtake position) prior to the time that Payout would have occurred if calculated on an Entitlement basis. While in theory the Farmor should not have an Entitlement basis for gas balancing purposes until Payout would have occurred under an Entitlements basis, some companies may reflect the Farmor just the same as any other working interest on the producer/producer gas imbalance statements after Payout (on sales basis) has occurred. Therefore, it is important to maintain records to determine the extent of the liability of the Farmor in the case that the well depletes prior to Payout on an Entitlements basis. This information should include the cumulative overproduction attributable to the Farmor's interest at Payout, the Farmor's cumulative Entitlements since Payout, and the Farmor's cumulative sales or takes since Payout. When the cumulative Entitlements since Payout exceed the overproduced volumes at Payout, the Farmor's liability is equal to the current cumulative over position (as shown on the producer/producer gas imbalance statement).

B. Based on Entitlements

Below is another example of a Payout involving multiple gas purchasers and variable gas prices using gas Entitlements instead of gas sales. The example and subsequent discussion are directed toward a Farmout situation but would also apply to any situation requiring Payout calculations. Remember, the Farmee is responsible for calculating Payout even if it is not the operator and should advise the operator of the Farmor's election upon Payout. It is acceptable for the party responsible for calculating the Payout Statement to calculate Payout revenue based on its own pricing experience since pricing data is seldom shared.

Example 6: Payout Based on Entitlements Calculation

Facts:

- 160-acre Unit
- Party "B" 40-acre Farm-in from Party "A"
- 1/16th Overriding Royalty with 25% WI conversion option
- Party "D" 40-acre Farm-in from Party "C"
- 1/8th Overriding Royalty with 25% WI conversion option
- Party "B" owns remaining 80 acres
- Costs
- \$250 M tangible
- \$550 M intangible
- \$10 M per month operating expense
- Sales
- Party "B" to Party "B1" at \$2/Mcf
- Party "D" to Party "D1" at \$3/Mcf
- Party "C" to Party "D1" at \$3/Mcf
- Entitlement
- First Six Months – 150 MMcf
- Second Six Months – 164 MMcf
- Second and Third Years – 20 MMcf/month
- Taxes are \$0.065/Mcf
- Royalty for all tracts is 1/8th paid on entitlement
- ORRI paid on entitlement
- Payout calculated on entitlement

Table 11: Revenue and Costs for Multiple Purchasers and Prices

Costs/Revenues Description	Amounts
Tangible Well Costs	$250,000
Intangible Well Costs	550,000
Operating Expense	10,000/month
Sales-Party "B" to Purchaser "B1"	Price: $2/Mcf
Sales-Party "D" to Purchaser "D1"	Price: $3/Mcf
Sales-Party "C" to Purchaser "D1"	Price: $3/Mcf
Entitlement Volumes for Unit	First Six Months: 150 MMcf Second Six Months: 164 MMcf Years Two and Three: 20 MMcf/month
Production Taxes*	$0.065/Mcf

* Assume same tax rate applies to all ownerships and corresponding acreages.

Figure 9: 160-acre Ownership Before Farmout

<table>
<tr><td>Tract “A” (40 acres)
* Party “A” WIO
* 1/8th Royalty</td><td rowspan="2">Tract “B” (80 acres)
* Party “B” WIO
* 1/8th Royalty</td></tr>
<tr><td>Tract “C” (40 acres)
* Party “C” WIO
* 1/8th Royalty</td></tr>
</table>

Figure 10: 160-acre Ownership After Farmout

<table>
<tr><td>Tract “A” (40 acres)
* Party “B” WIO
* 1/8th Royalty
* 1/16th ORRI - “A”</td><td rowspan="2">Tract “B” (80 acres)
* Party “B” WIO
* 1/8th Royalty</td></tr>
<tr><td>Tract “C” (40 acres)
* Party “D” WIO
* 1/8th Royalty
* 1/8th ORRI – “C”</td></tr>
</table>

Table 12: Payout Calculations Using Gas Entitlements

Payout (First Year)	"A" Tract 40-acre 1/16th ORRI $2/Mcf Price	"C" Tract 40-acre 1/8th ORRI $3/Mcf Price
Prior Balance to Payout	$0	$0
Well Costs ($800M x 40/160)	200,000	200,000
Operating Expenses (12 x $10M x 40/160 Acres)	30,000	30,000
Revenue First Six Months – 150 MMcf		
150 MMcf x $2 x 40/160 150 MMcf x $3 x 40/160	(75,000) 0	0 (112,500)
Less: Production Taxes (150 MMcf x 0.065) x 40/160	2,437	2,437
Royalty-1/8 x 150 MMcf x ($2 less 0.065) x 40/160 ($3 less 0.065) x 40/160	9,070 0	0 13,758
ORRI – 1/16 x 150 MMcf x ($2 less 0.065) x 40/160 1/8 x 150 MMcf x ($3 less 0.065) x 40/160	4,535 0	13,758
Second Six Months – 164 MMcf		
164 MMcf x $2 x 40/160 164 MMcf x $3 x 40/160	(82,000) 0	0 (123,000)
Less: Production Taxes (164 MMcf x 0.065 x 40/160)	2,665	2,665
Royalty - 1/8 x 164 MMcf x ($2 less 0.065) x 40/160 1/8 x 164 MMcf x ($3 less 0.065) x 40/160	9,917 0	0 15,042
ORRI - 1/16 x 164 MMcf x ($2 less 0.065) x 40/160 1/8 x 164 MMcf x ($3 less 0.065) x 40/160	4,958 0	0 15,042
Total Net Revenue	(123,418)	(172,798)
Balance to Payout	$106,582	$57,202

Since the revenue and operating costs are constant each month for the last twenty-four months, the change in the Payout balance will also be constant. Therefore, Payout dates can be determined as shown in the following example.

Table 13: Calculations to Determine Payout Dates

Monthly Change (Last Twenty-four Months)	"A" Tract 40-acre 1/16th ORRI $2/Mcf Price	"C" Tract 40-acre 1/8th ORRI $3/Mcf Price
Operating Expenses ($10M x 40/160 Acres)	$2,500	$2,500
Revenue – 20 MMcf 20 MMcf x $2 x 40/160 20 MMcf x $3 x 40/160	(10,000)	(15,000)
Less: Production Taxes (20 MMcf x 0.065) x 40/160	325	325
Royalty – 1/8 x 20 MMcf x ($2 less 0.065) x 40/160 1/8 x 20 MMcf x ($3 less 0.065) x 40/160	1,209	1,834
ORRI – 1/16 x 20 MMcf x ($2 less 0.065) x 40/160 1/8 x 20 MMcf x ($3 less 0.065) x 40/160	605	1,834
Total Revenue	(7,861)	(11,007)
Monthly Change in Payout	$(5,361)	$(8,507)

The balance to Payout after the first year for Tract "A" and Tract "C" is $106,582 and $57,202, respectively. Dividing this balance by their net gain each month of $5,361 and $8,507 indicates Payout will occur 19.9 months after the first year for Tract "A" and 6.7 months after the first year for Tract "C."

The previous example calculates Payout based on Entitlements and each Farmee calculates Payout on its price. Any imbalance existing at the points of Payout remains with each Farmee. The Farmors should each receive their share of production after Payout (i.e., assuming they elect to convert their ORRI to a working interest) since they are in a balanced gas status.

VII. NET PROFITS INTEREST

A. General

A Net Profits Interest may result from a special lease agreement or a Farmout agreement. A lease may be acquired from an assignor for a payment of cash and a fractional part of the net profits from production of the lease. Net Profits Interests are more commonly formed when a working interest owner assigns a working interest in a lease to another party, retaining what is referred to as a Net Profits Interest. In this arrangement, the assignee agrees to pay the assignor a specified percentage of the net profits from production attributable to that interest.

Net profits arrangements can have different provisions and definitions of Payout; therefore, the agreement and the accounting procedure should be reviewed carefully to determine the proper method of calculating the Net Profits Interest. The holder of the Net Profits Interest is usually not liable for losses in the development and operation of the lease, but these losses may be carried forward and recovered by the payor of the Net Profits Interest out of future net profits. When a profit is realized, payment is made to the net profits owner.

The revenue used to determine net profits may be based on either Entitlements or actual sales in gas balancing situations. When net profits are determined based on actual sales revenues and the payor is underproduced, the net profit account should also be adjusted for payments or receipts applicable to cash settlements related to gas imbalance. If the net profits are calculated based on entitlement, the cash settlement of gas imbalances would not impact the Net Profits Interest.

Example 7: Net Profits Calculation
Facts:

- Company "X" assigns 100% WI to "Y" in 160-acre lease
- 20% Net Profits Interest
- Net Profits - the excess of net revenue proceeds over the cost to drill, develop, and operate the well on the subject lease
- Period
- (A) represents completion of drilling operations
- (B), (C), and (D) represent subsequent period operations
- Net Revenue Applied - gross proceeds from production, less royalties and taxes

Table 14: Net Profits Calculations

Balance Forward	A	B	C	D
Costs Over Revenue	$0	$800,000	$326,875	$0
Current Period Activity	800,000	0	1,000	5,000
Operating Expenses	0	100,000	90,000	95,000
Workover Cost	0	0	0	250,000
Abandonment Cost Salvage Credit	0	0	0	0
Total Expenses	800,000	100,000	91,000	350,000

Net Revenue Applied	0	(573,125)	(581,500)	(275,000)
Net (Profit) Loss	800,000	(473,125)	(490,500)	75,000
Cumulative Net (Profit)/Loss	800,000	326,875	(163,625)	75,000
20% Net Profits Payments to "X"	0	0	32,725	0
Loss Carried Forward	$800,000	$326,875	$0	$75,000

VIII. CARRIED INTEREST

A. General

A Carried Interest is created any time a working interest owner of a property assumes or "carries" costs and risks attributable to another party's working interest. The Carried Interest can result from a specifically expressed contractual provision, an option extended by contract which is exercised, or an implied relationship resulting from an unsigned interest that may be due to either owners who cannot be located or owners who refuse to sign a joint operating agreement and/or oil and gas lease.

B. Signed Party to Operating Agreement

A Carried Interest, as noted above can result from a specific agreement contractually creating a Carried Interest. However, most Carried Interests are created by signed owners who exercise non-consent elections allowed by most operating agreements. This situation usually exists when a working interest owner elects not to participate in a well operation. However, a Carried Interest may also arise from activities or operations not involving wells, such as an election not to participate in a project team, the construction and installation of a platform or facilities, or as a remedy if a party is in default.

When an owner elects to go non-consent or is deemed to be non-consent, the cost and risk attributable to the non-consenting parties in the operation are governed by the options or provisions of the operating agreement or a Forced Pooling order. The cost and risk are borne by the working interest owners who elect to undertake the operation. These owners who participate in the operation are referred to as Consenting Owners or Participating Parties. The Consenting Owners who elect to carry the non-consenting parties' share of these costs are known as the carrying owners. The revised interest in the operation of each carrying owner is usually in the proportion that each carrying owner's working interest bears to the total working interest of all carrying owners.

If the operation results in a dry hole or unsuccessful completion, the Consenting Owners must plug and abandon the well, or a portion thereof, at their sole cost, risk, and expense. If any well drilled or operation conducted under such an arrangement results in a producer of oil and/or gas in paying quantities, the Consenting Owners complete and equip the well to produce at their sole cost and risk and the well is operated for the account of the Consenting Owners.

When drilling operations of any well are undertaken by the Consenting Owners, the Non-Consenting Owners relinquish all interest in the well/zone/reservoir until Payout. There may be exceptions, e.g., a Non-Consenting Owner may be allowed to join in a deepening or sidetracking operation. Most agreements contain provisions allowing the Consenting Owner to recover 100% of the costs carried for the Non-Consenting Owner, plus a penalty that is expressed as a percentage of those costs. The costs and penalty, if applicable, are recoverable from what would have been the Non-Consenting Owner's share of production from the well/zone/reservoir. The recoupment source,- well, zone, or reservoir, varies from one agreement to another and may also depend on the type of operation, so the agreement should be examined carefully to determine the appropriate recoupment sources.

In the case of any operation involving an existing well, the Consenting Owners are generally permitted to use, free of cost, all casing, tubing, and other equipment in the well, but the ownership of all such equipment remains unchanged. Some agreements provide that the Consenting Owners must pay for use of the equipment in certain circumstances, and this payment is usually added to the Payout account. Once again, the agreement should be examined thoroughly. Upon abandonment of the well, the Consenting Owners should account for all salvageable equipment to the owners with each owner receiving a proportionate share in kind or in value. If the Consenting Owners own the equipment and the credits for salvaged equipment results in Payout, the Non-Consenting Owner may be entitled to payment for its share of the salvage value that exceeds the Payout balance.

Normally when a party goes non-consent in an operation other than drilling, deepening, or sidetracking of the well, it is only non-consent in that particular zone. The non-consenting party may be entitled to participate in a recompletion to another zone or portion of the well. Refer to the applicable joint operating agreement for specifics.

C. Unsigned Party to Operating Agreement

Some states have statutes that govern the treatment of unsigned owners. In some cases, states may allow the party wishing to develop the property to "force pool" the unsigned party. The Forced Pooling order will govern the accounting and specify what penalty may be recovered. Other states have no statutes or Forced Pooling authority. The unsigned party is treated as a co-tenant and the carrying party is allowed to recover its costs. Unsigned owners may not sign, either because they cannot be located, or they elect not to sign an operating agreement for personal or business reasons. Any penalties that may be applied in these Payout calculations for unsigned parties would have to be in accordance with a Forced Pooling order or laws of the state in which the property is located. Readers are cautioned to seek legal advice. Operations conducted under statutes, Forced Pooling orders, and co-tenancy case law are not governed by accounting procedures.

D. Payout Calculation

Payout occurs when the carrying owner receives from the non-participating party's production proceeds, after deducting applicable royalties, certain Overriding Royalty interests, transportation costs, and production and severance taxes, an amount attributable to the percentage of each Non-Consenting Owner's interest being carried, which equals the following amounts:

a) The costs and expenses of drilling, testing, and completing the well.
b) The cost of any newly acquired surface equipment beyond the wellhead connections (stock tanks, separators, treaters, pumping equipment, and piping, etc.), plus the operating costs of the well until Payout.

The costs under "a" and "b" above may also be subject to the recovery percentages either provided for in the operating agreement, Forced Pooling order, or statute, as applicable.

E. Payout Statements

The non-consent provision of an operating agreement usually provides that within a specified time after the completion of a non-consent operation, the party conducting the operation should furnish each Non-Consenting Owner an inventory of the equipment in and connected to the well and a statement of the cost of drilling, testing, completing, and equipping the well for production. Typically, operating agreement require the operator to furnish the Payout Statement, even though it may not be a carrying party. In that case, it is necessary for the carrying party(ies) to furnish information to the operator as to the proceeds to be applied to the Payout calculation.

Each succeeding month or period as stated in the applicable agreement during the time the Consenting Owners are being reimbursed, the operator or Consenting Owners should furnish the Non-Consenting Owners with a statement of all costs incurred in the operation of the well plus penalties, if applicable, together with a statement of the quantities of hydrocarbons produced and net proceeds realized (less applicable burdens and taxes). Transportation costs may or may not be deducted, depending on the point of sale.

Following is an example of a Payout Statement for a Carried Interest when there is a single gas price, and no gas balancing involved. Should multiple gas purchasers, variable gas prices, and a gas balancing situation be involved, then Payout of the carried party could occur at different times for each carrying owner.

Example 8: Payout Statement

Facts:

- Owner C has a 20% WI
- Elects to go non-consent on a development well
- Subject to 1/8th royalty
- Costs
- Tangible - $250,000
- Intangible - $550,000
- Surface Equipment - $10,000
- Operating Expense - $100,000
- Revenue - $850,000
- Transportation and taxes - $100,000
- Operating agreement provides recovery of:
  - 300% for cost of drilling, completing, and equipping the wellhead connections;
  - 100% for all other costs and expenses.

Table 15: Carried Interest Calculations

Description	To-Date		
Prior Balance to Recover at MM/DD/YY	$0		
Current Expenditures			
Drilling and Completion Costs:			
Tangible Drilling	250,000		
Intangible Drilling	550,000		
Total Expenditures	800,000		
Recovery Percentage	300%	$2,400,000	
Operating and Other Costs:			
Surface Equipment	10,000		
Operating Expense	100,000		
Total Expenditures	110,000		
Recovery Percentage	100%	110,000	
Total Cost Recovery		2,510,000	
Carried Interest Percentage		20%	
Total Carried Interest of Costs to Recover		502,000	
Current Revenue:			
Gross Revenue	(850,000)		
Less: Transportation and Taxes	(100,000)		
Less: Royalty	(93,750)		
Net Revenue	656,250		
Carried Interest Percentage	20%		
Total Current Revenue		(131,250)	
Balance to be Recovered to MM/DD/YY			$370,750

F. Reversion of Interest

If and when the Consenting Owners recover the specified amounts from the proceeds of production attributable to a Non-Consenting Owner's interest, the relinquished interest will automatically revert to the Non-Consenting Owner at the point in time specified in the agreement. Unlike Farmout agreements, there is usually no back-in election under an operating agreement. After reversion, the Non-Consenting Owner owns the same interest in the well, including the operating rights and working interest, the related material and equipment, and the production from the well as it would have owned had all parties participated in the operation. Therefore, the Non-Consenting Owner shall pay its proportionate share of the subsequent costs of the operation of the well in accordance with the terms of the applicable operating agreement and accounting procedure or Forced Pooling if applicable.

It should be noted that when more than one Consenting Owner is carrying the interest of the Non-Consenting Owner or owners, there could be more than one Payout date; the carried party's interest reverts proportionately as each Payout occurs.

In the case of a co-tenant, the party is deemed never to have relinquished its interest and needs no reversion. From an accounting standpoint, a co-tenant is treated like a net profits owner.

IX. AUDIT RIGHTS

The governing agreement and its attached COPAS accounting procedure govern audit rights. COPAS Model Form Interpretation 36, *Audit Rights of Non-Participating and Non-Consenting Parties*, further elaborates on Audit Rights for Payout accounts. Generally, Non-Participating Parties with a Payout interest have until twenty-four months following the end of the calendar year in which the operator rendered a Payout Statement to audit the Payout Statement. Audit rights do not extend to any portion of the cumulative balances on the Payout Statement for which Audit Rights have expired.

Likewise, COPAS Accounting Guideline 22, *Producer Gas Imbalances*, Section II, Subsection I-Verification & Reconciliation of Imbalances (Audit Rights), describes that generally the non-operator should conduct audits within twenty-four months from the end of the calendar year in which gas balancing statements are received.

Revenue adjustments may be made at any time, and this document does not limit the operator's right to make such adjustments. Revenue adjustments may affect the Payout date and should be taken into consideration when calculating Payout. Generally, the Non-Participating Parties have until twenty-four months following the end of the calendar year in which the Payout Statement reflecting the adjustment was rendered to audit the adjustment impacting Payout.

Failure to provide Payout Statements to the non-consenting parties will extend the Non-Participating Party's Audit Rights.

To avoid confusion, the right to audit should be described in detail in the governing agreement. An example of such a provision could be as follows:

> The net profits owner, upon written notice to the operator, shall have twenty-four months from the end of the calendar year in which a net profits statement is rendered to audit all net profits accounts and records relating to the property for the period covered by such statements.

The theory behind the rendering of net profits statements as the basis for determining the audit period is similar to a joint venture billing, which is normally the basis for determining the audit period in a standard joint venture property and provides incentive for the Net Profits Interest payor to issue timely statements since failure to do so may extend Audit Rights.

If the net profit agreement does not specify Audit Rights or refer to an accounting procedure, it should not be assumed that the net profits owner has any Audit Rights. However, state or federal law may provide certain discovery rights.

X. GENERAL DISCUSSION

#1 Question - How should the following items related to revenue impact Payout calculations?
a. What revenues should be included in Payout calculations?
b. How should quality bank adjustments impact Payout revenue?
c. How do imbalance penalties impact Payout revenue?
d. How do operational flow orders impact Payout revenue?

Answer:

a. All revenues from products extracted or allocated to the properties impacted should be used in Payout; e.g., oil, gas, liquids, plant products net of associated processing, and/or transportation costs.

b. The term quality bank adjustments refers to valuation adjustments for product quality differences made through a central "quality bank." Central quality banks are maintained mostly by crude oil pipelines for quality differences between pipeline receipts and deliveries. In some instances, quality banks are maintained between upstream producers for the difference in the quality of crude at the lease/well and the quality at the pipeline receipt point (generally sales point). In these upstream situations, actual sales prices are adjusted via the quality bank to arrive at the actual value of the well/lease's production. If the point of valuation as defined by the applicable agreement is the well or lease and the point of sale of the product is downstream of the well or lease, any "upstream" quality bank adjustment should be included in Payout revenue. A quality bank adjustment downstream of the sales point (i.e., pipeline quality banks) would not normally impact the well or lease value and should not be included in the Payout revenue.

c. Point of valuation is also important when considering a pipeline imbalance penalty impact on Payout revenue. If the imbalance occurs downstream of the point of valuation and valuation is not determined through netting transportation costs against the sales price, the imbalance penalties should not be considered in Payout revenue. However, if transportation costs are netted from the sales price in determining well or lease values, the imbalance penalty could also be considered. If the penalty is incurred in the ordinary course of transporting gas and is not the result of the shipper's gross negligence or willful misconduct, it could be considered as a part of the transportation deduction in arriving at well or lease net revenues.

d. Operational flow orders may also be considered a part of transportation costs and netted against sales proceeds to arrive at net revenue. However, due to the nature of operational flow orders, it may be more difficult to prove that they are not the result of the shipper's gross negligence or willful misconduct. Thus, the party to the Payout may consider operational flow orders a penalty to be borne by the shipper only.

#2 Question - How do the following royalty situations impact Payout?

a. Royalty in-kind
b. When royalties are not a percentage of actual proceeds from the sale of the products (i.e., Office of Natural Resources Revenue dual accounting)

Answer:

a. Since royalty volumes are subtracted from the total volumes before determining the volumes available to the producer to sell, there is no need to value the royalty in-kind volumes. The revenues the producer receives are only for the net-of-royalty volumes. Therefore, using Table 15 to illustrate, simply begin the calculation with the net revenue received instead of referring to it as the gross revenue, then eliminate the royalty deduction.

b. The governing agreement should first be consulted for clarity to determine the appropriate royalty deduction on Payout revenue. Generally, the deduction should be based on actual payments made for royalties per applicable mineral lease and/or regulations.

#3 Question - Should revenue be shown on the Payout Statement in the month it is received or the production month? For example, should the revenue on a January Payout Statement be January production month or revenue received in January? Also, should expense data be rendered by accounting month or by activity month on a Payout Statement?

Answer:

The governing agreement should be consulted for clarity on how statements are to be prepared and how the Payout is to be calculated. If the governing agreement is silent, production month for revenue and activity month for expense items would be the ideal way to calculate a Payout Statement. In the past, some operators have rendered statements based on accounting month or receipt month, then adjusted the final Payout date based on production and activity information. If the governing agreement contains no conflicting language, the final Payout calculation and date should be based on production month for revenue and activity dates for expense.

#4 Question - Should indirect costs such as overhead and facilities be included in Payout calculations?

Answer:

Unless the joint operating agreement specifies otherwise, all costs that would have been paid by the Farmor or non-consent party, had they participated, should be included in the Payout.

#5 Question – Should Payouts be calculated on actual takes or Entitlements?

Answer:

The governing agreement for the Payout should be consulted for information on how the Payout is to be calculated. If the governing agreement is silent, the operator may choose whether to calculate the Payout based on actual takes or Entitlements. Once the method is selected, the method needs to be consistently applied to future Payout calculations, unless mutually agreed to by the parties. This document contains numerous examples involving takes and Entitlements and highlights items for operators to consider when calculating Payout Statements.

#6 Question - If the Entitlement method is used and a carrying party is not taking gas, what price should be used to determine the carrying party's Entitlement revenue?

Answer:

One solution is to use the market value of such gas, which raises the issue of how market value should be determined. There are many possible answers. The prices received by other parties in that area for that month could be deemed the market value. This information may be found in industry publications. The price last received by the party not taking gas could be utilized. If the company not taking its gas is booking revenue based on Entitlements, utilizing the price for which such gas is being booked would be another option. Another method is to use the same price as the price paid to the carrying party's royalty owners. The best answer to this question is to utilize the price that most closely represents the true market value for such gas not being sold. COPAS Accounting Guideline 22, *Producer Gas Imbalances*, should also be consulted as a reference in determining the revenue recognition method to be used in Payout calculations.

#7 Question – Who is responsible for calculating Payouts?

Answer:

For non-consent calculations, under most operating agreements the party conducting the operation is responsible for providing the initial Payout Statement upon completion of the operation. Thereafter, the operator is responsible for providing the Payout Statements. In a Carried Interest situation, when a carrying interest owner is marketing its own production, Payout for the carried party cannot be calculated properly unless its revenue information is furnished to the operator or the carrying owner calculates its own Payout and provides the information to the operator.

For Farmout arrangements, the Farmee is responsible for calculating Payout even if it is not the operator and should advise the operator of the Farmor's election upon Payout. It is not the responsibility of the operator to calculate Payouts such as these.

When calculating a Payout for a Net Profits Interest, if the operator has no contractual relationship with the owner of a Net Profits Interest, the operator is not responsible for calculating the Net Profits Interest. Rather, it is the responsibility of the party who entered into the net profits agreement with the payee.

#8 Question - What constitutes proof that Payout Statements were rendered?

Answer:

Payout Statements can be sent certified to provide proof that statements were rendered, but this is not generally a requirement if the agreement is silent.

#9 Question – How is an existing Payout calculated when a unit is formed?

Answer:

If the unitization agreement does not address this issue, the most equitable method should be utilized. The proposed method would be based upon a determination of unit interest derived from the particular well.

#10 Question - What impact does a non-consent election by a Farmee have on the Farmee's Overriding Royalty obligation to the Farmor?

Answer:

The Overriding Royalty obligation would transfer, proportionately, to those owners who have picked up the non-consent interest, if the override was properly disclosed and the joint operating agreement provided the carrying parties would bear the Overriding Royalty interest. However, if the Overriding Royalty interest was deemed a "Subsequent Created Burden" under the joint operating agreement, the Farmee may still be liable for paying the Overriding Royalty interest, even if it went non-consent. Readers are cautioned to examine all relevant agreements and seek legal advice.

#11 Question - If the Farmee goes non-consent, how does this impact the Payout of the Farmout interest and the back-in rights of the Farmor?

Answer:

Typically, when a Farmee goes non-consent, the Payout calculation of the Farmout interest essentially stops until the Payout of the non-consent operation occurs. This is due to the fact that once the Farmee goes non-consent, the Farmee is neither receiving any revenue nor liable for any costs until Payout of the non-consent operation occurs. Once the Payout of the non-consent operation occurs, the Payout of the Farmout interest would resume from the balance that existed prior to the non-consent operation. The Farmee is responsible for receiving the non-consent Payout Statement from the carrying owners and furnishing a copy to the Farmor along with an explanation. There are a variety of ways the agreements can be structured, and the relevant agreements should be examined to determine the party's legal rights and obligations. Readers are cautioned to examine all relevant documents and seek legal advice.

#12 Question - How are un-leased interests treated in Payout?

Answer:

An un-leased mineral interest owner may execute a joint operating agreement and participate with a cost-bearing interest. If the un-leased mineral interest owner refuses to grant a lease or sign an operating agreement it may be treated like a Carried Interest.

#13 Question - Are state and federal income taxes included on the Payout calculation?

Answer:

No. Payout is a before-tax calculation.

#14 Question - Should cash contributions received by the carrying party be applied to the Payout account? If so, should they be deducted from drilling costs before the application of any penalties?

Answer:

The operating or other relevant agreements should be examined to determine the proper treatment of cash contributions. If the contract is silent or unclear, the payment should be applied to the Payout Statement. When an upfront cash contribution is made to participate in the well prior to drilling, no penalties should apply to the extent of the contribution made. When an after-the-fact buyback is made, however, it is more equitable that penalties be applied.

#15 Question - How should working interest revenue be handled after Payout?

Answer:

Since Payout calculations require data from previous time periods, the Payout calculation is often not available for some time after Payout has occurred. If an owner who reverts to a WI elects to take its product in-kind, several months after Payout may pass before the owner can notify its purchaser and nominate its additional production. During this time, the carrying owner or the Farmee will have continued to sell production attributable to the applicable interest. The carrying owner or Farmee may also have continued to pay royalties on behalf of this interest. Administratively, it would appear to be more efficient for a cash settlement to occur for the interim period and take in-kind to occur after the Payout Settlement Date. Payout Settlement Date, as defined in the Glossary, is the point in time defined in the appropriate agreement, which is after the Payout date and determines when all changes must be in place to properly record revenue and expenses at the after-payout working interest.

While the agreement referred to above may not often be the original agreement that created the Payout situation, it could be an informal letter agreement used to ensure a smooth transition after Payout. This settlement date is recommended when reverting owners take production in-kind and/or begin to pay their own royalty to avoid building of imbalances (gas or oil) and the need to make adjustments for royalty owners.

Calculation of Payout can be very complex. If Farmout and joint operating agreements contained specific wording as to how Payout is to be calculated, the task would be much simpler.

XI. GLOSSARY

AUDIT RIGHTS - The right to audit the operator's accounts and records relating to the joint account.

BACK-IN - A point in the life of a project, generally after Payout as defined in a particular agreement, where a Farmor has the right to participate with a working interest (i.e., certain percentage of the interest under its Farmout agreement). The Farmor may or may not relinquish a portion of a retained overriding-royalty interest in exchange for a working interest. Under some agreements, when a Farmor backs-in, it does not relinquish anything.

CASING POINT - The depth in a well at which casing is set. When a well has reached its authorized depth (i.e., depth as approved through an AFE) and all tests have been completed and the results thereof furnished to the working interest owners, the parties then have a certain period of time in which to elect to participate in the setting of the casing and the completion attempt.

CARRIED INTEREST - The interest of an owner or lessee who does not participate in the project or operation and assumes no liability for its share of the costs or risk associated with the activity or operations. The interest will be borne by one or more of the other working interest owners.

CONSENTING OWNER (or Participating Party) - A working interest owner who elects to participate in a project or operation or is otherwise obligated to participate.

ENTITLEMENTS - The working or royalty interest share of total gas available for delivery, production less gas used in operations (COPAS AG-22, *Producer Gas Imbalances*)

FARMOUT/FARM-IN - A sharing arrangement in which oil and gas operating rights (working interest) are transferred to another party for such other party to develop all or part of the acreage at its sole cost, risk, and expense.

FARMEE - The party accepting the risk of developing the acreage subject to the terms and conditions of the Farmout agreement, in exchange for the right to earn an assignment of interest.

FARMOR - The party to a Farmout agreement who owns certain oil and gas rights. The Farmor elects not to assume the entire risk of exploring for the oil and/or gas and enters into an agreement to assign certain rights to the Farmee upon the Farmee performing specified drilling and completion obligations.

FORCED POOLING - Pooling of leased tracts undertaken without the willing cooperation of all the parties. Forced Pooling may occur as the result of an order from a state regulatory agency, an order sought by one or more of the parties affected.

NET PROFITS INTEREST - An interest in production created from the working interest and measured by a certain percentage of the net profits (as defined in the contract) from the operation of the property.

NON-CONSENTING OWNER (or Non-Participating Party) - A working interest owner that elects not to participate in a project or operation or is otherwise deemed to have elected not to participate and is relieved of its obligation to bear the cost and risks associated with the project or operation.

OVERRIDING ROYALTY (ORRI) - Interest carved out of the lessee's working interest, entitling its owner to a fraction of production free of any production or operating expense, but not free of production or severance tax levied on production. An Overriding Royalty may be created by grant or by reservation. Commonly, an override is reserved by the assignor in a Farmout agreement or other assignment. An override's duration corresponds to that of the lease from which it was created.

PAYOUT - Point in time when proceeds of production attributable to an interest equal the cost of drilling and completing, operating, and in some cases a penalty, allocated to that interest. The term "Payout" is sometimes used as an adjective, as in "Payout accounting" or "Payout balance" or "the well is in Payout status." It is also used as a verb, as in "when will the well pay out?"

PAYOUT STATEMENT - A statement provided to all affected parties (whether Farmout, non-consent, or others) that details status of Payout.

PAYOUT SETTLEMENT DATE - The point in time which may be agreed to by the parties as defined in the appropriate agreement, after the Payout date, which determines when all changes must be in place to properly record revenue and expense at the after-payout working interest.

PRODUCER IMBALANCE - The extent to which one or more owners of gas from a property have delivered to a transporter a quantity of gas (production delivery) which is more or less than their working or royalty interest share of the total gas available for delivery (production less used in operations) or entitlement. (COPAS AG-22, *Producer Gas Imbalances*)

REVERSIONARY OVERRIDING ROYALTY INTEREST - An Overriding Royalty interest generally granted within a Farmout agreement that has the option to convert (revert) to a working interest upon Payout of the well (project). Exact terms of the interest are generally defined within the agreement.

ROYALTY INTEREST - The share of the production or proceeds there from reserved to the lessor under the terms of a mineral lease. Normally, royalty interests are free of all costs of production (as distinguished from marketing) except production taxes. (COPAS AG-15, *Gas Accounting Manual*)

WORKING INTEREST OWNER (WIO) - A party who holds or owns a leasehold interest and is responsible for the cost of exploring, developing, and operating a lease.

Employee Benefits Limitation

MODEL FORM INTERPRETATION 14

Publication/Revision Date - December 2019

Board Approved

PRUTCOM Approved: January 28, 2025

FOREWORD

This publication was originally published under the guidelines and procedures in existence prior to the revised publication procedure COPAS established in April 1999. The Council approved the re-classification of this publication in its current form based on its content but recognized that it had not received the same approval levels as publications developed and published under the current publication procedures. The actual approval level is noted on the cover page. As with all COPAS publications under the new standards, if this publication is revised or updated, it will also be required to meet the content and approval standards of the current COPAS publication process prior to issuance.

COPAS MODEL FORM INTERPRETATION 14

ISSUED: October 29, 1982

SUBJECT: Employee Benefits Limitation

PREFACE:

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest Standing Committee and approved by the COPAS Board and is recommended as a guide in accounting for joint interest operations.

PROBLEM:

Because of frequent changes in the cost of providing employee benefits and the burden of amending various COPAS model form accounting procedures accordingly, COPAS recently approved a procedure whereby this limitation may be automatically revised without amending the operating agreement. In general, most accounting procedures now provide or are modified to provide that the operator shall charge the joint account for employee benefits an amount equivalent to the operator's actual cost not to exceed a given percent or the percent most recently recommended by COPAS. A conflict may arise if the operator's actual cost is less than the amount chargeable under the given percentage since it could be argued the operator may still charge the percentage most recently recommended by COPAS. Another conflict may arise if the numerical percentage provided for in a particular agreement exceeds the percentage recommended by COPAS in some later year, as it could be argued the operator may still charge the higher of the two figures.

INTERPRETATION:

The COPAS intent in publishing an employee benefits limit each year is twofold: (1) to place a ceiling on the amount the operator may charge for employee benefits and (2) to provide for automatic revision of this ceiling, based on an annual industry survey of these costs, without formally amending the agreements. Therefore, it is suggested that when accounting procedures in existing agreements or new agreements are modified to adopt the COPAS limitation for employee benefits that the numerical percentage in the printed form be deleted so the accounting procedure will provide "Operator's current cost of employee benefits shall be Operator's actual cost not to exceed the percent most recently recommended by COPAS."

Council of Petroleum Accountants Societies

Turning Energy Into Synergy

Operator Affiliates and Related Entities

MODEL FORM INTERPRETATION 18

Publication/Revision Date - April 2010

Council Approved

PRUTCOM Approved: January 28, 2025

COPAS MODEL FORM INTERPRETATION 18

Operator Affiliates and Related Entities

PROBLEM:

Some operators have affiliate,[1] subsidiary, and/or related entities (hereinafter referred to as "Related Entity" or "Related Entities") which supply goods and services used on the joint property. Questions sometimes arise regarding the proper manner for charging the joint account for goods and services provided by the Related Entities. Examples of situations leading to non-operator concerns about the propriety of costs charged to the joint account include:

1. An operator's technical personnel, such as engineers and geologists, may be organized as a Related Entity technical service company and charged to the joint account at consultant daily rates in excess of actual costs.

2. An operator may supply field labor (pumpers, roustabouts, first level supervisors, etc.) through a Related Entity that is a contracting service company and charged to the joint account at commercial rates in excess of actual costs.

3. An operator may have Related Entities from which they purchase materials such as tubular goods, wellhead equipment, mud, bits, fuel, etc., at prices which are higher than those paid by the Related Entity. The prices paid by the operator and charged to the joint account may be higher than those charged by the Related Entities' suppliers because trade or other discounts are not passed on to the joint account or the operator simply marks-up the price paid to the actual outside supplier.

4. An operator may have Related Entities which provide services involving the use of equipment or facilities, such as drilling contractors, well servicing contractors, trucking contractors, helicopter contractors, boat contractors, real time operation centers, etc., which are charged at commercial rates rather than rates provided in COPAS model form accounting procedures.

5. An operator may outsource goods/services covered by an overhead rate to a Related Entity and then attempt to justify charging the joint account on the premise that the costs are chargeable under the Services provision of the COPAS model form accounting procedures.

6. Joint Account charges for Related Entities' chargeable goods and/or services may include overhead functions that may have been formerly provided by the operator and, in some cases, a profit element.

These charges usually pass from one related company to another by way of formal invoices which appear to be arm's-length transactions.

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[1] **From the COPAS 2005 Model Form Accounting Procedure, "Affiliate" means "…For a person, another person that controls, is controlled by, or is under common control with that person." In this definition, (a) "control" means ownership by one person, directly or indirectly, of more than 50 percent of the voting securities of a corporation or, for other persons, the equivalent ownership interest (such as partnership interests), and (b) "person" means an individual, corporation, partnership, trust, estate, unincorporated organization, association, or other legal entity**.

In light of the above concerns, there is a need for guidance on these issues.

INTERPRETATION:

The operator's Related Entities sometimes provide goods and services for joint operations which are charged at rates or prices comparable to those charged by other entities, but the use of Related Entities is not justification for circumventing provisions of the accounting procedure. The purpose of the Labor, Material and Equipment and Facilities provisions in the COPAS model form accounting procedures is to assure the operator's employees, material purchased from outside sources and any equipment or facilities which are owned by the operator and serve the joint property are charged to the joint account at actual cost, without a mark-up. In determining whether employees are those of the operator, whether material is charged at the price paid by the operator, or whether equipment or facilities are owned or furnished by the operator, the term "operator" includes entities which are "related" to the operator unless the following criteria are met at the time of the transactions:

1. The Related Entity must either historically or currently have conducted a substantial amount of its business with companies other than the operator or other Related Entities. These criteria should be met by the Related Entity in total as well as for the particular services or products provided. The Related Entity should not merely serve as a vehicle for rebilling services or products provided by unrelated companies; and

2. Goods and services provided by the Related Entity should be priced on terms that do not exceed the lesser of (1) those offered by the Related Entity to its most favored customers or (2) those offered to or obtainable by the operator from unrelated entities providing such services or products in the geographical area.

Therefore, unless the Related Entity is able to comply with the criteria of the preceding paragraph, (1) the services of employees of a Related Entity shall be charged to the joint account at the actual cost incurred by the Related Entity, without mark-up, (2) material purchased for use on the joint property from the Related Entity shall be charged to the joint account at the price paid by the Related Entity to an independent third party, after deduction of all discounts actually taken, and (3) any equipment or facilities which are owned by a Related Entity and serve the joint property shall be charged to the joint account at the rates specified for operator-owned equipment and facilities in the accounting procedure.

The overhead provision of the accounting procedure describes, in general terms, the functions covered by the overhead rate. The operator receives an overhead fee to perform these functions and can source these functions through employees, Related Entities, or third parties. Outsourcing overhead functions to a Related Entity does not make that function directly chargeable to the joint account.

It is not practical to precisely define every instance in which an entity providing labor, material, equipment, or facilities is related to the operator. However, any entity in control of, controlled by or under common control of the operator, or any entity which has a significant number of common employees, management, officers, directors or ownership with the operator, should be evaluated with regard to the criteria above, regardless of whether the operator and/or its Related Entities are corporations, partnerships, sole proprietorships, divisions, etc. A non-operator should not be harmed by the operator's decision to use a Related Entity rather than provide the goods/services in-house or through a third party. Substance must prevail over form.

Upon request, the operator should make available to the non-operators a list of all of the Related Entities that are used in conducting the operations of the property. Moreover, the accounting procedure and operating agreement generally grant a non-operator the right to verify the validity of charges to the joint account.

The information in this document is intended to aid in implementing the terms of the COPAS model form accounting procedures. However, the operating agreement, accounting procedure, and other relevant agreements governing a particular property will always take precedence over this document and should be taken into consideration.

The COPAS 1995, COPAS 1998 Project Team, and COPAS 2005 Model Form Accounting Procedures all have specific language governing Affiliate charges. This Model Form Interpretation should not be interpreted as overriding or changing the intent of these model forms.

Discounts

MODEL FORM INTERPRETATION 23

Publication/Revision Date - October 2016

Council Approved

PRUTCOM Approved: January 28, 2025

COPAS MODEL FORM INTERPRETATION 23

ISSUED: October 28, 2016

SUBJECT: Discounts

INTRODUCTION:

Following review of this COPAS Model Form Interpretation ("MFI) by various Petroleum Accountants Societies through their representation on the Joint Interest and Audit Standing Committees and approval by the Council of Petroleum Accountants Societies, Inc., COPAS recommends it as a guide for handling accounting for "discounts" as described and discussed in this document. This information is intended to aid in implementing the terms of the various COPAS model form accounting procedures, but if the interpretations in this document conflict with any applicable joint operating agreement, accounting procedure, or other agreement governing the joint property or operations, the applicable agreement will take precedence. In particular, at times language is added to a joint operating agreement or accounting procedure regarding the types of discounts discussed in this document. The parties to the agreement should seek appropriate legal, technical, and other advice if there is any question or conflict between a specific agreement and this document.

BACKGROUND:

With the myriad types and manners of discounts negotiated by operators with vendors, questions arise as to (1) the types of discounts to be credited to the joint account, (2) the operator's obligation to credit the joint account for discounts offered or earned on goods and services, whether or not the discounts were actually taken, and (3) how cash calls and other circumstances may affect if and how discounts should be credited to the joint account.

Some non-operators believe all discounts offered should be credited to the joint account whether or not taken because (1) the operator is compensated for handling the accounting function through one or more overhead assessments, and (2) if the operator cash-called the non-operator for the monthly expenses or project costs it had the money on hand to timely pay invoices.

An operator might not take a discount due to a pricing, quality, or quantity discrepancy, a question about delivery, potential disputes, lien issues, misdirected invoices, internal approval processes, or staffing problems.

Some operators believe that certain discounts earned are not for credit to the joint account because the discounts were earned based on expenditures beyond those pertaining to the joint account.

All COPAS model form accounting procedures from the COPAS 1962 Model Form Accounting Procedure through the Deepwater Model Form Accounting Procedure address discounts on material purchased by providing that the joint account is due credit for discounts received, with the COPAS Deepwater Model Form Accounting Procedure using the word “taken” instead of “received.” See Exhibit 1 for the relevant COPAS model form accounting procedure language. The COPAS model form accounting procedures, however, do not contain similar specific language on discounts offered or received on services.

This document provides guidance and COPAS model form accounting procedure references for the various types of discounts in the industry.

The four types of discounts discussed are not a complete list of all the types of discounts because the types and accounting for discounts may change and/or take different forms through the years as companies change the way they conduct business. Operators and non-operators are advised to have substance prevail over form when applying the guidelines in this MFI.

INTERPRETATION:

As a general concept, but as discussed and limited hereinafter, all discounts received should be credited to the joint account(s) of the operations or other activities that gave rise to or contributed to the discount.

Cash Discounts

Cash Discounts are discounts offered for meeting payment terms in the time period and manner prescribed by the seller, such as “2% 10 days, net 30.” Typically, the invoice identifies the availability of these discounts.

Operators should make good faith efforts to take advantage of all Cash Discounts offered because taking such discounts reduces joint account cash expense. The business or other reason(s) for a Missed Discount (a discount offered by the vendor that is not taken or received) identified in an audit or otherwise should be explained to a non-operator inquiring about the Missed Discount. While paying the proper amount on vendor invoices is a priority, operators should develop internal accounts payable procedures that will allow it to routinely take most Cash Discounts, even though it is realized an operator may occasionally miss a Cash Discount offered. This is true for even those of lesser amounts, because the cumulative effect of individual small discounts can be significant over time.

The COPAS model form accounting procedures require that all discounts received for materials and purchases be credited to the joint account. For materials, refer to Section IV.1 in all COPAS model form accounting procedures from the COPAS 1962 Model Form Accounting Procedure through the COPAS Deepwater Model Form Accounting Procedure (Section VI.1 in the COPAS 1995 Model Form Accounting Procedure), as detailed in Exhibit 1. The language in all COPAS model form accounting procedures is almost identical to that in the COPAS 2005 Model Form Accounting Procedure that “Direct purchases shall be charged to the Joint account at the price paid by the Operator after deduction of all discounts received.” The COPAS Deepwater Model Form Accounting Procedure replaces “received” with “taken.” For Services, refer to the Services provision within Section II (Direct Charges) in the COPAS 1962 Model Form Accounting Procedure through the COPAS Deepwater Model Form Accounting Procedures (Section III.5 in the

COPAS 1995 Model Form Accounting Procedure), as detailed in Exhibit 2. The Services section in each COPAS model form accounting procedure is slightly different, but all begin by allowing a direct charge for "The cost of contract services…" The widely held view in COPAS is that "cost" means the net cost after credit for any discounts received or taken.

Further, "Joint Account" is a defined term in all COPAS model form accounting procedures, with little difference among the COPAS 1962 Model Form Accounting Procedure through the COPAS Deepwater Model Form Accounting Procedure. For illustration, the COPAS 2005 Model Form Accounting Procedure defines the Joint Account as "…The account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties…" As such, all discounts must be credited to the applicable joint account because they constitute part of the "charges paid and credits received."

There is no COPAS model form accounting procedure language supporting a non-operator's right to receive credit for a Missed Discount. The operator could have not taken a discount for a variety of reasons, including (1) the operator's review procedures or activity level did not allow for payment within the prescribed discount period, (2) the operator took additional time reviewing the invoiced items or discussing them with the vendor, (3) the operator temporarily misplaced the invoice, or, (4) simply because the operator did not see the discount terms when processing the invoice. Thus, if the operator paid the invoiced amount without applying an offered discount, such invoiced amount is the cost of the service. Similarly, joint account is "…the account showing the charges paid and credits received," so if the operator did not take a Cash Discount, the joint account would reflect the actual amount paid for that service.

If the operator did not take an offered Cash Discount but then paid the invoice within the prescribed period to earn the discount, the operator would be expected to make a good faith effort to recover the overpayment and credit the joint account where the material was used or service rendered.

The above interpretations would hold true even if the non-operator advanced its share of monthly or project costs or operating expenses because the model forms do not make such a qualification in the above- cited provisions, even if the advanced amount was enough to pay all bills received during the month. The purpose of the cash call is simply to require non-operators to share an operation's financial burden in advance of the normal joint interest billing cycle so the operator does not float/finance the costs of an operation. In addition, cash call payments are to cover overall estimated expected cash outlays, not payments for specific invoices.

If a non-operator can demonstrate a pattern or confirm a policy or established procedure whereby the operator forgoes all or most discounts only because it desires to hold onto cash rather than pay a lesser amount early, it should consult the joint operating agreement or other governing agreement to determine what recourse it has.

Trade Discounts

Trade Discounts are material and services discounts off the vendor's usual or "list prices" to meet competition or adjust to market conditions. The invoice will sometimes, but not always, identify a Trade Discount.

Operators should verify that the dollar amount or discount percentage is the agreed-upon discount amount/rate and preferably have vendors apply the discount to each invoice so that the proper activity receives credit.

For the same reasons discussed for Cash Discounts, the operator should credit all Trade Discounts received to the joint account(s) that paid for the materials or received the services. If the discount is not issued on each invoice, the operator should allocate the discount amount when received to the joint account(s) to which the materials or services pertain. A non-operator may ask the operator for a copy of the vendor contract, purchase order, bids, price lists, or other documentation evidencing the dollar or percentage discount amount negotiated so the non-operator can verify the existence of and amounts and rates of credits granted.

Trade Discount percentages can be significant, sometimes as much as 60% or more off a vendor's list price for a material or service. These discounts can be structured as a traditional "net 30" or as "Pay discounted amount within 30 days, then pay gross invoice amount." Regardless of the terms or the practice of billing the discounted amount, the joint account is to be charged the amount actually paid by the operator for the materials or service net of all discounts received or taken.

Performance Discounts

Performance Discounts are discounts agreed to by vendors for unsatisfactory performance of a particular job or service. These discounts can be credited against the invoice for the specific service or applied over a prescribed period of time to future invoices for materials or services for activities which may or may not be for the same joint account where the discount was earned.

Operators should maintain a record of the activity(ies) or expenditures that generated the discount so that they can apply credits to the proper account.

Performance Discounts issued in a lump sum on a credit memo directly referring to the activity that generated the discount should be credited to that activity because that would result in the joint account being charged for "The cost of contract services, equipment, and utilities…" as the Services provision in the COPAS model form accounting procedures require (refer to Exhibit 2). Similarly, issuing a Performance Discount on materials to the activity generating the discount would comply with the COPAS model form accounting procedure language in Exhibit 1.

Performance Discounts issued on future invoices or over time on a specified number of activities or operations, such as the next five drilling wells, location builds, or logging jobs, should be credited to the activity or operation that generated the discount because it was that prior activity or operation that earned the discount. It is not proper to book the credits to the joint account(s) of the property(ies) or project(s) where the credits were issued merely because the credits were on invoices for such property(ies) or project(s). Doing so would result in an overstatement of services and/or materials costs to the activity or operation to which the discount pertains and would not match the credits issued to the specific properties/projects that actually earned the discount.

The operator should make a good faith effort to get a refund, or to have the discounts issued for future operations on the same property that generated the discount. Barring that, the possible timing difference between the completion of the activity/operation owed the discount and the vendor crediting the operator for the discount could create a difficult situation to administer. If the vendor issues credit on a subsequent invoice for the same property having the same interests as the project/operation that earned the discount, but for a different activity or operation, it may be acceptable to book the credit to the new activity or operation rather than make retroactive adjustments, especially if the Authorization for Expenditure ("AFE") for the prior activity or operation is closed.

If the Performance Discount amount is to be paid over a period of time or number of future activities, the operator is not expected to credit the joint account for the full Performance Discount amount at the time the discount amount was agreed upon. Rather, the partial or periodic amounts should be credited to the proper joint account(s) upon receipt; any residual amount paid to the operator if the future activities are not sufficient to pay off the remaining Performance Discount amount should also be credited, and only to the joint account(s) of the properties and projects which earned the discount.

Volume Discounts

Volume Discounts are material and services discounts offered based on the purchase of specific volumes of material or services over a prescribed time period. These are negotiated items, most often included in the contract or bid between the operator and the vendor. One type of Volume Discount is commonly referred to as a rebate, where the vendor issues quarterly, semi-annual, annual, other time period, or lump sum payments or credits after the operator qualifies for the rebate. Another type is one in which the vendor applies a "percentage off" discount on future purchases of materials or services.

Rebates should be credited to the projects and properties in a fair and equitable manner which reflects the dollar values or other criteria used to calculate the discount amount. That is, all properties and projects whose expenditures or service usage contributed to earn the rebate should receive a share of the rebate. Operators should maintain a record of the activity(ies) or expenditures that generated the rebate so that proper credit(s) can be issued.

Volume Discounts not paid to the operator as a rebate, but rather as a "percentage off" or dollar amount reduction to rates or amounts charged for materials or services in subsequent periods or years should be included in the amount billed to the joint account for that specific vendor invoice where such discounts are issued because such represents the cost of materials or service to the project or operation billed on that invoice. "Percentage off" discounts applied to an invoice for materials would be credited to the joint account if the materials qualify as a direct purchase; "percentage off" discounts applied to materials properly charged into an operator's inventory would not be credited to the joint account because the material would be charged to the joint account according to the material transfer provisions in the governing accounting procedure. In this case, the discount pertained to inventory activity, not the property or activity that eventually used the material.

A non-operator may ask the operator for a copy of the vendor contract or other documentation evidencing the rebate or "percentage off" amounts so the non-operator can verify the existence of and amounts and rates of credits granted.

Rebates from Financial Institutions

Some operators pay some invoices using a procurement card or credit card (card). Financial institutions issuing the cards sometimes offer cash rebates on these purchases, often as monthly or quarterly percentage rebates, so the question arises as to whether such rebates should be credited to the activity whose charges generated the rebate. COPAS believes that such card rebates, whether in cash or other form, from the issuing financial institution, are part of the operator's treasury function and not part of the cost of service as intended by the COPAS model form accounting procedures "Services" language cited in Exhibit 2. The COPAS model form accounting procedure "Services" language pertains to monetary matters and payment terms between vendors and the operator, not between the operator and a financial institution. Likewise, any annual fees, late fees, or financing and interest charges from financial institutions are also part of the operator's treasury function and not to be charged to the joint account, just as ATM, wire transfer, EFT, or check fees are not directly charged.

Also, the COPAS model form accounting procedure definition of the "Joint Account" ("...means the account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties, but does not include proceeds attributable to hydrocarbons and by-products produced under the Agreement") (COPAS 2005 Model Form Accounting Procedure) does not include charges and credits from a financial institution because those types of transactions are outside the scope of the accounting procedure. See Exhibit 3 for the definition of the Joint Account in all COPAS model form accounting procedures.

Vendor Contracts and Agreements

The sections on Trade Discounts and Volume Discounts discuss that an operator may be requested to provide additional documentation beyond invoices evidencing the dollar or percentage discount amount negotiated, such as a contract, work order, or purchase order in order to determine if all discounts earned and paid or applied to future expenditures have been properly credited. Many operators consider such documentation to be proprietary and not required to be provided to a non-operator, so COPAS recommends the parties discuss such issues and that reasonableness, materiality, and audit scope be considered in any such requests.

If the operator is unable or unwilling to provide some requested documentation due to confidentiality provisions in applicable agreements, good faith interpretations of applicable antitrust laws, and/or other company policies, the operator and non-operator may determine other means to provide an additional level of assurance beyond invoices. Some solutions might include: (1) obtaining a vendor's approval to show rate sheets or other relevant excerpts from the vendor contract; (2) written confirmation by the operator that all discounts made available and taken by the operator have been passed to the joint account; or, (3) allowing a mutually acceptable independent audit firm to review the contract(s) and verify that any discounts have been accounted for properly. One outcome may be inclusion in the audit report of the request and the operator's refusal to provide the data.

EXHIBIT 1

The COPAS model form accounting procedures provide the following regarding direct material purchases:

COPAS 1962 Model Form Accounting Procedure: Section IV.1
1. Purchases
Material purchased and service procured shall be charged at the price paid by Operator after deduction of all discounts actually received.

COPAS 1968 Model Form Accounting Procedure: Section IV.1
1. Purchases
Material purchased and service procured shall be charged at the price paid by Operator after deduction of all discounts actually received.

COPAS 1974 Model Form Accounting Procedure: Section IV.1
1. Purchases
Material purchased shall be charged at the price paid by Operator after deduction of all discounts received. In case of Material found to be defective or returned to vendor for any other reason, credit shall be passed to the Joint Account when adjustment has been received by the Operator.

COPAS 1976 Offshore Model Form Accounting Procedure: Section IV.1
1. Purchases
Material purchased shall be charged at the price paid by Operator after deduction of all discounts received. In case of Material found to be defective or returned to vendor for any other reason, credit shall be passed to the Joint Account when adjustment has been received by the Operator.

COPAS 1984 Model Form Accounting Procedure: Section IV.1
1. PURCHASES
Material purchased shall be charged at the price paid by Operator after deduction of all discounts received. In case of Material found to be defective or returned to vendor for any other reasons, credit shall be passed to the Joint Account when adjustment has been received by the Operator.

COPAS 1986 Offshore Model Form Accounting Procedure: Section IV.1
1. Purchases
Material purchased shall be charged at the price paid by Operator after deduction of all discounts received. In case of Material found to be defective or returned to vendor for any other reasons, credit shall be passed to the Joint Account when adjustment has been received by the Operator.

COPAS 1995 Model Form Accounting Procedure: Section VI.1

1. DIRECT PURCHASES

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts received. A direct purchase is determined to occur when an agreement is made between an Operator and a third party for the acquisition of Materials for a specific well site or location. Material provided by the Operator under "vendor stocking programs," where the initial use is for a Joint Property and title of the Material does not pass from the vendor until usage, is considered a direct purchase. If Material is found to be defective or is returned to the vendor for any other reason, credit shall be passed to the Joint Account when adjustments have been received by the Operator from the manufacturer, distributor, or agent.

COPAS 1998 Project Team Model Form Accounting Procedure: Section IV.1

1. DIRECT PURCHASES

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts received. A direct purchase is determined to occur when an agreement is made between an Operator and a third party for the acquisition of Materials for a specific well site or location. Material provided by the Operator under "vendor stocking programs," where the initial use is for a Joint Property and title of the Material does not pass from the vendor until usage, is considered a direct purchase. If Material is found to be defective or is returned to the vendor for any other reason, credit shall be passed to the Joint Account when adjustments have been received by the Operator from the manufacturer, distributor, or agent.

COPAS 2005 Model Form Accounting Procedure: Section IV.1

1. DIRECT PURCHASES

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts received. The Operator shall make good faith efforts to take discounts offered by suppliers but shall not be liable for failure to take discounts except to the extent such failure was the result of the Operator's gross negligence or willful misconduct. A direct purchase shall be deemed to occur when an agreement is made between an Operator and a third party for the acquisition of Material for a specific well site or location. Material provided by the Operator under "vendor stocking programs," where the initial use is for a Joint Property and title of the Material does not pass from the manufacturer, distributor, or agent until usage, is considered a direct purchase. If Material is found to be defective or is returned to the manufacturer, distributor, or agent for any other reason, credit shall be passed to the Joint Account within sixty (60) days after the Operator has received adjustment from the manufacturer, distributor, or agent.

COPAS Deepwater Model Form Accounting Procedure: Section IV.1

1. DIRECT PURCHASES

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts taken. The Operator shall make good faith efforts to take discounts offered by suppliers but shall not be liable for failure to take discounts except to the extent of the Operator's liability under the Agreement. A direct purchase shall be deemed to occur when an agreement is made between the Operator and a third party for the acquisition of Material for Joint Operations. Material provided by the Operator under "vendor stocking programs," when the initial use is for the Joint Operations and title of the Material does not pass from the manufacturer, distributor, or agent until usage of the Material takes place, is considered a direct purchase. Actual freight associated with direct purchases is chargeable to the Joint Account.

EXHIBIT 2

The COPAS model form accounting procedures allow direct charges for "Services" as follows:

COPAS 1962 Model Form Accounting Procedure: Section II.6

A. The cost of contract services and utilities procured from outside sources other than services covered by Paragraph 8 of this Section II and Paragraph 2 of Section III.

COPAS 1968 Model Form Accounting Procedure: Section II.6

A. The cost of contract services and utilities procured from outside sources other than services covered by Paragraph 8 of this Section II and Paragraph 1.B of Section III. The cost of professional consultant services shall not be charged to the Joint Account unless agreed to by the Operator and Non-Operators.

COPAS 1974 Model Form Accounting Procedure: Section II.6

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 9 of Section II and Paragraph I.ii of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the Overhead rates. The cost of professional consultant services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

COPAS 1976 Offshore Model Form Accounting Procedure: Section II.6

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 9 of Section II and Paragraph I of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the Overhead rates. The cost of professional consultant services or contract services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

COPAS 1984 Model Form Accounting Procedure: Section II.7

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 10 of Section II and Paragraphs i, ii, and iii, of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the overhead rates. The cost of professional consultant services or contract services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

COPAS 1986 Offshore Model Form Accounting Procedure: Section II.6
The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 9 of Section II and Paragraphs i and ii of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the overhead rates. The cost of professional consultant services or contract services of technical personnel directly engaged in the operation of the Joint Property shall be charged to the Joint Account if such charges are excluded from the overhead rates.

COPAS 1995 Model Form Accounting Procedure: Section III.5
The cost of contract services, equipment, and utilities provided by sources other than the Operator.

COPAS 1998 Project Team Model Form Accounting Procedure: Section II.5
The cost of contract services, equipment, and utilities used in the conduct of Joint Operations and provided by sources other than the Parties, except for contract services, equipment, and utilities covered by the Section III overhead provisions, Paragraph 7 of this Section II, or excluded under Paragraph 9 of this Section II. Notwithstanding anything herein to the contrary, the cost of contract personnel assigned to the Project Team are directly chargeable to the Joint Account.

COPAS 2005 Model Form Accounting Procedure: Section II.5
The cost of contract services, equipment, and utilities used in the conduct of Joint Operations, except for contract services, equipment, and utilities covered by Section III (*Overhead*), or Section II.7 (*Affiliates*), or excluded under Section II.9 (*Legal Expense*). Awards paid to contractors shall be chargeable pursuant to COPAS MFI-49, *Employee and Contractor Awards*.

The costs of third party Technical Services are chargeable to the extent excluded from the overhead rates under Section III (*Overhead*).

COPAS Deepwater Model Form Accounting Procedure: Section II.5
The cost of services provided by third parties, including Technical Services provided in the conduct of Joint Operations, but excluding services covered by Section II.7 (*Affiliate Services*), Section II.9 (*Legal Expense*), or Section III (*Overhead*). The cost of awards to third parties shall be chargeable to the Joint Account (i) if such third parties are chargeable under this Section II.5, and (ii) to the extent such awards pertain to services provided for activities or operations conducted under the Agreement. The cost of operational, technical, HSE or government-mandated training shall be chargeable to the Joint Account, for third parties who are chargeable under this Section II.5.

EXHIBIT 3

The COPAS model form accounting procedures define the "Joint Account" as follows:

COPAS 1962 Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges and credits accruing because of the Joint Operations and which are to be shared by the Parties.

COPAS 1968 Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges and credits accruing because of the Joint Operations and which are to be shared by the Parties.

COPAS 1974 Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and which are to be shared by the Parties.

COPAS 1976 Offshore Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and which are to be shared by the Parties.

COPAS 1984 Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and which are to be shared by the Parties.

COPAS 1986 Offshore Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and which are to be shared by the Parties.

COPAS 1995 Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and which are to be shared by the Parties.

COPAS 1998 Project Team Model Form Accounting Procedure: Section I.1
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties.

COPAS 2005 Model Form Accounting Procedure: Section I.1

"Joint Account" means the account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties, but does not include proceeds attributable to hydrocarbons and by-products produced under the Agreement.

COPAS Deepwater Model Form Accounting Procedure: Section I.1

"Joint Account" means the account showing the charges paid and credits received in the conduct of the Joint Operations that are to be shared by the Parties, but does not include accounts pertaining to volumes or proceeds attributable to Hydrocarbons and by-products produced under the Agreement.

Council of Petroleum Accountants Societies

Turning Energy Into Synergy

Employee Benefits and Percentage Limitation

MODEL FORM INTERPRETATION 27

Publication/Revision Date - October 2011

Council Approved

PRUTCOM Approved: January 28, 2025

I. INTRODUCTION

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest Standing Committee and Audit Standing Committee and approved by the Council of Petroleum Accountants Societies, Inc. COPAS recommends this as a guide in implementing the terms of the various COPAS model form accounting procedures. However, the joint operating agreement, accounting procedure, and other relevant agreements governing the joint property will take precedence if they conflict with this document.

II. BACKGROUND

The COPAS model form accounting procedures allow the operator to make a direct charge to the joint account for certain personnel and their payroll burdens and employee benefits, including the current cost of the operator's established employee benefits plans. Exhibit A contains the employee benefits provisions from the COPAS model form accounting procedures.

The operator recoups these employee benefits costs by applying a percentage, representative of the operator's actual cost of providing the employee benefits, to chargeable personnel's salaries and wages. Questions may arise as to how the employee benefits rate should be calculated and whether specific employee benefits plans, or other costs should or should not be included in the calculation.

Although employee benefits are generally chargeable to the joint account, the employee benefits percentage applied to labor charges may be subject to limitations under the applicable contract, and in some cases, that limitation is the percentage most recently recommended by COPAS. In addition to providing guidance on the calculation of employee benefits, COPAS conducts a yearly survey of employee benefits costs for companies which operate oil and gas properties to determine the upper limitation on employee benefits charges. The survey uses this MFI as a guide.

III. EMPLOYEE BENEFITS RATE CALCULATION

Guidelines for calculating the employee benefits rate are as follows:

The formula for determining an operator's employee benefits rate is employee benefits costs divided by payroll costs.

Operators typically use prior year costs to calculate a rate to apply to the current year's labor charges. Consequently, the operator must wait until the prior year's cost data is available before the revised rate can be calculated and implemented. Many operators calculate the rate to apply commencing April 1 until March 31 of the following year. The timing of applying the new rate is not material so long as the operator is consistent from year to year.

<u>Example</u>:

Employee benefits costs paid by the operator in the year just completed that may be included in the calculation are as follows:

Category	Amount
Group life insurance	$ 502,300
Health benefit plans	4,655,500
Pension/retirement	6,682,800
Savings plan	2,991,600
Tuition assistance	31,400
Total employee benefits costs	$14,863,600

Operator's payroll cost for the same pool of workers for the year just completed that are subject to the employee benefits calculation are as follows:

Category	Amount
Straight time	$35,566,200
Overtime	5,169,400
Holiday	189,200
Vacation	2,955,200
Sickness	631,800
Disability	24,000
Jury duty, other paid leave	315,300
Total payroll costs	$44,851,100

The current year employee benefits rate would be $14,863,600 divided by $44,851,100 equals 33%.

The amount the operator may charge depends on the contract. The operator may charge either the 33% rate, or a lesser rate if the contractual limit is less than 33%.

The cost of employee benefits plans may be borne entirely by the operator or jointly by the operator and the employees; however, only the operator's share of these costs is included in employee benefits costs.

Most COPAS model form accounting procedures, other than the COPAS 1995 and 1998 Project Team Model Form Accounting Procedures, refer to the current cost of providing employee benefits. Therefore, if the operator under-recovers its employee benefits costs in one year, it cannot roll that loss forward and include it in the following year's calculation. For example, if the COPAS limit is 30% and the operator's actual rate is 35%, the resulting under-recovery of employee benefits costs may not be rolled into the following year's rate calculation. Although the over-recovery or under-recovery from a prior year may not be included in the current year rate calculation, prior year charges may be adjusted, subject to the 24-month adjustment period.

The pool of labor and employee benefits costs used to calculate the rate may vary from one operator to the next. The operator should be consistent from year to year. COPAS recommends that integrated companies exclude downstream organizations' employee benefits and labor costs as retail employees typically have different employee benefit plans. Likewise, the calculation should exclude employee benefits and labor costs attributable to international operations, or any affiliated entity that has employee benefit plans that differ from billable employees' benefit plans.

The operator should ensure the pay types used in its calculation match the pay types that have employee benefits attached to them in its joint interest accounting system. The operator might over-recover or under-recover its employee benefits costs if this does not occur. For example, if the operator does not attach employee benefits to incentive pay in its joint interest accounting system, but includes incentive pay in its rate calculation, the employee benefits rate will be diluted (i.e., lower) and the operator will not recover part of its employee benefits costs.

The following lists identify employee benefits and payroll costs that should and should not be included in the operator's employee benefits percentage calculation.' Irrespective of other criteria, to be included in the employee benefits rate calculation the item must be an established employee benefits plan that is made available to all full-time employees in the pool on a regular basis.

A. Employee Benefits Costs Included in the Employee Benefits Rate Calculation (i.e., Numerator)

- Accidental death & dismemberment insurance
- Adoption assistance
- Bonus that is not pay-at-risk or incentivized pay (e.g., Christmas bonus) [1]
- Business travel insurance
- Dependent care/referral
- Group legal plans
- Health plans - dental, medical, mental health, vision, wellness plans, spending accounts
- Life insurance
- Disability insurance
- Pension - service cost component only [2]
- Post-retirement benefits - only the service cost component for current employees [3]
- Profit sharing plans that do not qualify as incentive pay [1]
- Savings plans
- Tuition assistance

The items in section A are not intended to be "all inclusive" listings of employee benefits due to the variety of employee benefit plans available, changes in plans, and changes in employee benefits laws and regulations. This list serves as a guide in comparing other employee benefit plans.

B. Payroll Costs Included in the Employee Benefits Rate Calculation (i.e., Denominator)

- Cost of living adjustment
- Disability pay
- Death in family leave
- Family leave (if paid time)
- Holiday pay
- Incentive pay [1]
- Jury duty
- Medical leave

- Military leave
- Overtime
- Retention pay
- Straight time
- Vacation & vacation buy-back

C. Items Not Included in the Employee Benefits Rate Calculation

- Benefit costs for retired employees ("pay-as-you-go" costs)
- Employee benefits administration
- Cafeteria subsidies
- Club/organization memberships
- Company aircraft usage
- Company car for personal usage
- Company credit card discounts
- Company medical facility
- Company sports & recreation facilities
- Early retirement incentives
- Federal Insurance Contributions Act ("FICA")
- Health club membership
- Matching donation plans
- Medicare
- Performance awards [4]
- Physical examinations
- Promotional gifts
- Referral bonuses
- Relocation reimbursement
- Retirement dinners/parties
- Service awards
- Severance pay
- Sign-on bonuses
- Stock options
- Suggestion awards [4]
- Transit or parking passes/subsidies
- Travel expense reimbursement (actual or per diem allowances)
- Unemployment tax (federal and state)
- Workers' compensation insurance

FICA, Medicare, federal and state unemployment insurance, and worker's compensation insurance are not included in the rate calculation even though they are a part of payroll costs. The reason for this is because these items typically do not have an employee benefits rate attached to them when they go through the joint interest billing ("JIB") system. However, if the operator's JIB system attaches employee benefits to these items, they should be included in the employee benefits calculation.

Some of the items in Section C may be directly chargeable to the joint account under other provisions of the COPAS model form accounting procedure and some items may be considered overhead costs. It is beyond the scope of this document to address these issues. Readers should seek advice from appropriate experts and/or other COPAS documents for more information on these matters.

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1. According to COPAS MFI-37, *Incentive Compensation Costs*, incentive pay is based on predetermined metrics, such as production targets or profitability, and must be a formally documented policy of the operator. Incentive pay is considered variable pay, pay at risk, and pay for performance or gainsharing. Refer to COPAS MFI-37 for further discussion of incentive pay. A bonus, on the other hand, is discretionary; it is not part of a defined pay plan and not tied to predetermined metrics.

2. Financial Accounting Standards Board ("FASB"), *Accounting Standards Codifications (ASC) Topic 715-30, Compensation - Retirement Benefits, Defined Benefit Plans - Pensions.*

3. Financial Accounting Standards Board ("FASB"), *Accounting Standards Codifications (ASC) Topic 715-60, Compensation - Retirement Benefits, Defined Benefit Plans - Other Postretirement.*

4. Refer to COPAS MFI-49, *Employee and Contractor Awards,* for more information on performance or suggestion awards.

Exhibit A

These are all direct quotes from the COPAS model form accounting procedures noted.

COPAS 1962 Model Form Accounting Procedure - Section II.3
Operator's current cost of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost; provided however, the total of such charges shall not exceed ten percent (10%) of Operator's labor costs chargeable to the Joint Account under Paragraphs 2A and 2B of this Section II and Paragraph 1 of Section III.

COPAS 1968 Model Form Accounting Procedure - Section II.3
Operator's current cost of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost chargeable to the Joint Account under Paragraphs 2A and 2B of this Section II and Paragraph 1A of Section III shall be chargeable as indicated in the subparagraph selected below:

A. [ ] Operator's actual cost.
B. [ ] Operator's actual cost not to exceed fifteen per cent (15%).

COPAS 1974 Model Form Accounting Procedure - Section II.3
Operator's current costs of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost chargeable to the Joint Account under Paragraphs 2A and 2B of this Section II shall be Operator's actual cost not to exceed twenty percent (20%).

COPAS 1976 Offshore Model Form Accounting Procedure - Section II.3
Operator's current costs of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost chargeable to the Joint Account under Paragraphs 2A and 2B of this Section II shall be Operator's actual cost not to exceed twenty percent (20%) or percent most recently recommended by the Council of Petroleum Accountants Societies of North America.

COPAS 1984 Model Form Accounting Procedure - Section II.4
Operator's current costs of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost chargeable to the Joint Account under Paragraphs 3A and 3B of this Section II shall be Operator's actual cost not to exceed the percent most recently recommended by the Council of Petroleum Accountants Societies.

COPAS 1986 Offshore Model Form Accounting Procedure - Section II.3
Operator's current costs of established plans for employees' group life insurance, hospitalization, pension, retirement, stock purchase, thrift, bonus, and other benefit plans of a like nature, applicable to Operator's labor cost chargeable to the Joint Account under Paragraphs 2A and 2B of this Section II shall be Operator's actual cost not to exceed the percent most recently recommended by the Council of Petroleum Accountants Societies.

COPAS 1995 Model Form Accounting Procedure - Section III.2.E
The Operator's cost of established plans for employees benefits as described in COPAS MFI-27

determined by applying the employee benefits percent most recently published by COPAS to the chargeable salaries and wages.

COPAS 1998 Project Team Model Form Accounting Procedure - Section II.2.F
Cost of established plans for employees' benefits as described in COPAS MFI-27, determined by applying the employee benefits limitation percentage most recently recommended by COPAS to the chargeable salaries and wages.

COPAS 2005 Model Form Accounting Procedure - Section II.2.G
Operator's current cost of established plans for employee benefits, as described in COPAS MFI-27 ("Employee Benefits Chargeable to Joint Operations and Subject to Percentage Limitation"), applicable to the Operator's labor costs chargeable to the Joint Account under Sections II.2.A and B based on the Operator's actual cost not to exceed the employee benefits limitation percentage most recently recommended by COPAS.

Note: COPAS MFI-27 is now titled *Employee Benefits and Percentage Limitation*

Turning Energy Into Synergy

Self-Insurance for Workers' Compensation and Employers' Liability Insurance

MODEL FORM INTERPRETATION 31

Publication/Revision Date - December 2019

Board Approved

PRUTCOM Approved: January 28, 2025

FOREWORD

This publication was originally published under the guidelines and procedures in existence prior to the revised publication procedure COPAS established in April 1999. The Council approved the re-classification of this publication in its current form based on its content but recognized that it had not received the same approval levels as publications developed and published under the current publication procedures. The actual approval level is noted on the cover page. As with all COPAS publications under the new standards, if this publication is revised or updated, it will also be required to meet the content and approval standards of the current COPAS publication process prior to issuance.

COPAS MODEL FORM INTERPRETATION 31

ISSUED: August 1995
REVISED: December 1996

Self-Insurance for Workers' Compensation and Employers' Liability Insurance

PREFACE:

This COPAS Model Form Interpretation has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest Standing Committee and approved by the Board of Directors of the Council of Petroleum Accountants Societies, Inc. ("COPAS") and is recommended as a guide in accounting for joint interest operations.

PROBLEM:

Most COPAS model form accounting procedures and their Interpretations provide for an operator to charge the joint account directly for the cost of workers' compensation and employers' liability insurance premiums, or if the operator is self-insured, the operator shall charge for the cost of self-insurance, not to exceed manual rates. The cost of an operator's self-insurance is often difficult for the operator and joint venture auditor to identify and track through the operator's organization to the joint property.

Therefore, a need exists to develop a mechanism to easily identify the cost of self-insurance, whereby the costs charged to the joint account for self-insurance are equitable to the operator and non-operator. The methodology for determining the cost of self-insurance should be easy to administer, easy to verify and reasonably indicative of the cost of risk. The use of manual rates fits all of these criteria.

INTERPRETATION:

The operator's cost of self-insurance should be calculated using manual rates, as regulated by the state in which the joint property is located, or in the case of offshore operations, the adjacent state's manual rates plus the applicable United States Longshore and Harbor Workers' Compensation Act or Jones Act surcharge. The surcharge is applicable for any joint operations located offshore of the United States including state territorial waters, or on navigable waters of the Unites States (including inland waterways) capable of supporting interstate commerce, or on land adjacent to such offshore waters or navigable waters where such joint operations include maritime-related activities. However, the United States Supreme Court has held that the Act does not apply to non-seamen working on fixed platforms within state territorial boundaries unless they are engaged in traditional maritime employment, such as the loading and unloading of vessels.

Manual rates represent the total cost per $100 of payroll for the average employer in a given classification based on industry statistics. The manual rates are subject to close regulatory scrutiny, and in some states understate the true cost of workers' compensation.

The objective of the classification system is to group employees into appropriate classifications so that the rate for each classification reflects the exposures common to those employees. The most commonly identified class codes in the oil and gas industry are those related to lease, drilling, gas plant, or shorebase operations, and in some instances, administrative functions.

To provide uniformity in rates, COPAS recommends the following guidelines be adopted as a basis for calculating an operator's charge for basic workers' compensation and employers' liability self-insurance to the joint account:

1) Commencing in 1997 and annually thereafter, COPAS will publish the recommended rates and effective dates, or provide the source for the rates.

2) Class Code 1320 - Production Operations is recommended as the preferred class code for personnel engaged in production operations and located on-site.

3) In considering operator's on-site drilling personnel (including supervisory) or other technical personnel (involved in drilling operations) having special and specific engineering, geological or other professional skills, Class Code 6235 - Drilling Operations is recommended in calculating the self-insurance charge to the joint account. Drilling operations as used herein, shall be deemed to include drilling or redrilling oil, gas, or service wells; erection or dismantling of drilling rigs; formation fracturing; cementing and installation of casing while conducting drilling; recompleting; reworking; sidetracking; and plugging and abandonment operations.

4) For off-site technical personnel who are directly chargeable to the joint account pursuant to the terms of the accounting procedures applicable to the joint operations, it is recommended that the operator use Class Code 8810 - Clerical for assessing workers' compensation self-insurance charges.

5) Some accounting procedures permit the operator to charge the joint account directly for the salaries and wages of various employees located in the district, division, region, or corporate office (as opposed to recovering such costs through overhead). Examples of such personnel include field assistants, material coordinators, safety and environmental personnel, and computer support personnel. In the event such personnel are directly chargeable, Class Code 8810 - Clerical is recommended in calculating the self-insurance charge.

6) For most operators, the duties performed by shorebase personnel involve dispatching and coordinating the transportation of materials, and company or third-party personnel. Although the tasks involving a higher degree of risk (such as operating heavy equipment or loading/unloading) are often performed by contract personnel, Class Code 8227 - Permanent Yard is recommended for operator's shore base personnel.

7) The charge to the joint account is calculated by applying the manual rate to 100% of the employee's salary and wages, inclusive of overtime.

A table specifying the class codes to be used is as follows:

JOB FUNCTION/POSITION	CLASS CODE
Production operations • Foremen • Roustabouts • Pumpers • Electricians • Mechanics • Corrosion specialists • Well testing • Measurement • Other operating functions	1320
Drilling	6235
Shore base	8227
Chargeable technical - on-site (on drill deck) Chargeable technical - on-site (not on drill deck) Chargeable technical - off-site	6235 1320 8810
Gas plant	1320

In case of disputes arising over the use of class codes, it is recommended that the parties avail themselves of the inspection services offered by the National Council on Compensation Insurance ("NCCI") or other licensed agency to determine the proper classification of personnel. It is recommended that the cost of the inspection service be chargeable to the joint account.

Turning Energy Into Synergy

Employee and Contractor Training Costs

MODEL FORM INTERPRETATION 35

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COPAS MODEL FORM INTERPRETATION 35
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COPAS MODEL FORM INTERPRETATION 35

INTRODUCTION:

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accounting Societies through representation on the COPAS Joint Interest and Audit Standing Committees and has been approved by the Council of Petroleum Accountants Societies, Inc. It provides a guide for determining the chargeability of training costs to the joint account. However, the joint operating agreement, accounting procedure, and other relevant agreements governing the joint property control in any conflict with this document.

BACKGROUND:

Prior to 1995, the COPAS model form accounting procedures and the various model form operating agreements were silent as to the chargeability of training costs. The COPAS 1995 Model Form Accounting Procedure permitted charging the joint account with costs incurred for government mandated training conducted on the joint property. In 1997, COPAS published MFI-35, *Employee and Contractor Training Costs,* to provide guidance to the industry on the chargeability of certain employee training costs. Even under the 1997 edition of MFI-35 and the COPAS 1995, 1998, 2005, and 2012 Model Form Accounting Procedures, which contain provisions concerning training costs, implementation questions arise about their application in particular situations as to personnel, contractors, and training courses, as well as allocation issues.

This revision to MFI-35 is necessary because the 1997 edition addressed charges for training field employee personnel only. Changes in the industry, such as outsourcing of field operations and increasing regulations, as well as ongoing questions about types of training and cost allocations, created a need to revise this MFI. The lack of specificity in the agreements can lead to different interpretations as to the types of training costs that are chargeable and/or under what circumstances training is chargeable. This MFI provides guidelines regarding the chargeability of training costs when the agreement is not specific.

Users of the COPAS 2005 Model Form Accounting Procedure should note that Section II.2.F (Direct Charges - Labor) of that form refers to this MFI, as follows:

> Training costs as specified in COPAS MFI-35 ("Charging of Training Costs to the Joint Account") for personnel whose salaries and wages are chargeable under Section II.2.A. This training charge shall include the wages, salaries, training course cost, and Personal Expenses incurred during the training session. The training cost shall be charged or allocated to the property or properties directly benefiting from the training. The cost of the training course shall not exceed prevailing commercial rates, where such rates are available.
>
> Note: MFI-35 is now titled *Employee and Contractor Training Costs.*

INTERPRETATION:

Training costs can include, but are not limited to, the following items:

- Salaries, wages, and amounts paid to people being trained, both employees and contractors;
- Personal expenses, such as meals and lodging of people being trained;
- Course related costs (e.g., registration fees, books, or other media).

<u>Company Labor</u>

Operating agreements grant the operator authority to select employees and to determine their hours and compensation (See Exhibit 6). Operators consider training to be an essential part of field employees' duties and attending training as a job requirement. In some cases, training is required by laws or regulations and operating agreements require the operator to adhere to all applicable federal, state, and local laws, ordinances, rules, regulations, and orders. Because training is a component of field employees' jobs, salaries and wages of field employees incurred during training that is directly applicable to joint operations are chargeable under the labor provision of the direct charges section of the COPAS model form accounting procedure, provided such training provides direct benefit to the property. Training classified as Technical training in the table below meets that criterion.

The chargeability of training costs for technical employees (e.g., engineers and geologists) can be more complicated because their salaries and wages are not always directly chargeable to the joint account. Most accounting procedures contain elections as to the chargeability of technical labor, and, frequently, their time is chargeable under some circumstances but not others. For example, their time might be chargeable when working on-site, but not chargeable when off-site. Sometimes their time is chargeable when working off-site on a major construction project or a project team, but not when working off-site in connection with drilling or producing operations. The variability in contract terms and situations can make it difficult to determine whether training costs for technical personnel are chargeable.

When the technical person is chargeable only under certain circumstances, training is chargeable if it (i) is classified as Technical in the table below, (ii) directly benefits the property/project, and (iii) is in connection with technical services chargeable to the joint account. For example, if an on-site technical person's time is chargeable and the individual receives Health, Safety, and Environmental ("HSE") or other operator-required training in connection with boarding a rig, transport vehicle, or platform, the training cost is chargeable. Also, if the technical person whose time is chargeable to a construction project receives training specifically in connection with the project and the training benefits the project, the training time is chargeable. If the technical person's time is not billable even when on-site, the training is not billable even when on-site; the training is not chargeable.

Accounting for training of the operator's or non-operator's affiliate personnel should be treated in the same manner, billable or non-billable, as if the person were an employee of the operator or non-operator.

Contract Labor

Operators provide training for contractors to ensure they understand and meet the operator's field operating policies and procedures as well as any government regulations, thus minimizing the cost and risk to the properties they serve. In some cases, such as boarding a platform or entering a facility where hazardous materials are present, contractors are required by regulations, operator's safety standards, and/or contracts to take training. While contractors may be expected to have the basic level of training when they begin work for an operator, that is not always the case in areas where there is high activity and high demand for workers. In addition, new technology and tools can necessitate training. Regardless of the contractor's experience level, operating agreements grant the operator broad authority to hire and establish operating guidelines for contractors that serve the property. This gives the operator discretion to provide training for contractors and charge the cost under the Services provision of Section II (Direct Charges) of COPAS model form accounting procedures. Just as for field and technical employees, charges for contractor training apply only for Technical training in connection with chargeable activities that directly benefit the property. This Services provision limits charges to contractors performing chargeable functions. It does not allow charges for contractors performing overhead functions. In summary, Technical training of chargeable contractors that provides direct benefit to the operations is chargeable to the joint account.

Chargeable vs. Non-Chargeable Training

The following table summarizes examples of types of chargeable and non-chargeable training under the categories of Technical and Non-Technical, respectively. The items in the table do not represent an all-inclusive list; rather they serve as examples. As previously noted, costs associated with Technical training are chargeable if the services provided by those trained are also directly chargeable. Costs associated with Non-Technical training are not directly chargeable without approval of non-operators.

Technical (Chargeable Training) vs. Non-Technical (Non-Chargeable Training)

Technical	Non-Technical
• Government-mandated or recommended • Job specific for current assignment, such as - Artificial lift - Compressor - Instrumentation - Automation Systems • Safety **(all types)*** • Environmental • Computing skill - Computer applications used in field operations (refer to COPAS MFI-44, *Field Computer and Communication Systems*) - Technical computing applications associated with billable services	• Administrative, accounting, clerical or reporting functions • Routine practices, procedures, team building exercises and reorganizations • Career development - Performance - Managerial - Leadership - Personal development - Equal Employment Opportunity (EEO) - Ethics • Word processing, spreadsheet, and computer operating system

*Behavior-based safety training may be delivered in a classroom setting or through one-on-one interaction. Training specifically related to safety and operational issues that improve the safety environment on the joint property.

Personal Expenses

Employees and contract personnel sometimes incur personal expenses, such as travel costs, in connection with training. Section II (Direct Charges) of the accounting procedures allows the operator to directly charge the joint account for personal expenses of employees whose salaries and wages are chargeable to the joint account. Therefore, reasonable expenses incurred by employees in connection with Technical training that are reimbursed by the operator are directly chargeable. Personal expenses for Non-Technical training are an overhead cost under the accounting procedure.

Most COPAS model form accounting procedures do not specifically address personal expenses for contractors. However, it is common practice for operators to reimburse contractors for this cost or pay for the contractor training upfront. If the operator pays for these expenses, the costs are part of the cost of the contract service and are chargeable under the Services provision of Section II (Direct Charges) COPAS model form accounting procedures.

In some circumstances, such as deepwater project teams, non-operator personnel, affiliate personnel, and contractors assigned to the joint property incur personal expenses reimbursed by that person's employer or the operator, to attend training. The operating agreements and accounting procedures for deepwater properties, as an example, typically provide that these costs get the same accounting treatment as personal expenses incurred by operator employees.

In summary, for Technical training, if the person's time is chargeable to the joint account, his or her personal expenses are also chargeable, regardless of whether that person is the operator's employee, non-operator employee, affiliate employee, or contractor.

Course Related Costs

In addition to the labor costs and personal expenses of the person being trained, other training costs include course fees paid to the operator or third parties for tuition, books, or other materials. Training fees also include the instructors, facility rental, and course development. To ensure that third party and operator-provided services are treated alike, the cost of tuition, books, instructors, materials, and facilities are chargeable, regardless of who provides it. However, the cost of operator-developed training should not exceed the commercial rates prevailing in the area for comparable training, unless otherwise approved by the non-operator. Some operating agreements and accounting procedures contain limitations on charges by the operator's affiliates, so the operator should review the operating agreement and accounting procedure for restrictions on charges for training provided by an affiliate.

Allocations

If both chargeable and non-chargeable personnel attend the same Technical training, the training costs should be allocated among the chargeable and non-chargeable personnel. Unless the training costs can be specifically determined for each person, headcount is a fair and reasonable way to allocate training costs for training attended by both chargeable and non-chargeable people.

For a chargeable person attending chargeable training, if the individual serves more than one property, all properties that benefit should bear a share of the training costs. Normally, the allocation of training costs mirrors the allocation of the person's salary or wages. However, if the training is specific to one type of operation, e.g., waterflood, the training costs should be charged only to the property or properties that will benefit.

Some training, even though classified as Technical in the table above, may have no benefit to the properties currently served by that person because it is preparation for a new job assignment. In that case, the training cost is not chargeable to the properties currently served. For example, if a lease operator attends a gas lift training course in anticipation of a reassignment to a property that uses gas lift, the training cost should not be charged to the current properties served that do not use gas lift. The training may be charged to the property that will benefit, if known. The operator should consider materiality and practicality when deciding how to allocate small charges.

If the person receiving chargeable training works on construction and drilling projects, it can be difficult to match the cost to the properties that will benefit. For example, drilling personnel attend blow-out prevention training annually. The properties that will benefit are those that the individual will work on over the course of the next year. At the time the person receives the training, it may be unknown which properties will receive the benefit. So, the operator should make a reasonable effort to charge the training costs to the property or properties that will benefit from the training. Practices include: (1) charging a portion of the cost to the properties served at the time of the training and the same amount to operations served subsequent to the training, with a true-up at the end of the year; or, (2) allocating the cost to all the properties in the allocation pool that could be served by that person.

Exhibits 1 through 5 contain provisions from the COPAS model form accounting procedures pertaining to the various cost components related to training (company labor, contract labor/services, operator owned facilities/equipment furnished by the operator, personal expenses, and training costs). Exhibit 6 contains sample operating agreement provisions relating to the operator's authority to determine staffing needs and job responsibilities, which includes training.

These references support charging Technical training costs for both employees of the operator and contractors to the joint account. Please consult your specific operating agreement/accounting procedure.

EXHIBIT 1: COMPANY LABOR

COPAS 1962 Model Form Accounting Procedure

II. 2. Labor

A. Salaries and wages of Operator's employees directly engaged on the Joint Property in the conduct of the Joint Operations, and salaries or wages of technical employees who are temporarily assigned to and directly employed on the Joint Property.

COPAS 1968 Model Form Accounting Procedure

II. 2. Labor

A. (1) Salaries and wages of Operator's employees directly employed on the Joint Property in the conduct of Joint Operations.

(2) Salaries of first-level supervisors in the field if such charges are excluded from overhead rates in Option A of Section III.

(3) Salaries and wages of technical employees temporarily assigned to and directly employed on the Joint Property if such charges are excluded from overhead rates in Option B of Section III.

(4) Salaries and wages of technical employees either temporarily or permanently assigned to and directly employed in the operation of the Joint Property if such charges are excluded from overhead rates in Option C of Section III.

COPAS 1974 Model Form Accounting Procedure

II. 2. Labor

A. (1) Salaries and wages of Operator's field employees directly employed on the Joint Property in the conduct of Joint Operations.

(2) Salaries of First Level Supervisors in the field.

(3) Salaries and wages of Technical Employees directly employed on the Joint Property if such charges are excluded from Overhead rates.

COPAS 1976 Offshore Model Form Accounting Procedure

II. 2. Labor

A. (1) Salaries and wages of Operator's field employees directly employed on the Joint Property in the conduct of Joint Operations.

(2) Salaries and wages of Operator's employees directly employed on Shore Based Facilities or other Offshore Facilities serving the Joint Property if such costs are not charged under Paragraph 7 of this Section II.

(3) Salaries of First Level Supervisors in the field.

(4) Salaries and wages of Technical Employees directly employed on the Joint Property if such charges are excluded from the Overhead rates.

COPAS 1984 Model Form Accounting Procedure

II. 3. LABOR

A. (1) Salaries and wages of Operator's field employees directly employed on the Joint Property in the conduct of Joint Operations.

(2) Salaries of First Level Supervisors in the field.

(3) Salaries and wages of Technical Employees directly employed on the Joint Property if such charges are excluded from the overhead rates.

(4) Salaries and wages of Technical Employees either temporarily or permanently assigned to and directly employed in the operation of the Joint Property if such charges are excluded from the overhead rates.

COPAS 1986 Offshore Model Form Accounting Procedure

II. 2. Labor

A. (1) Salaries and wages of Operator's field employees directly employed on the Joint Property in the conduct of Joint Operations.

(2) Salaries and wages of Operator's employees directly employed on Shore Base Facilities or other Offshore Facilities serving the Joint Property if such costs are not charged under Paragraph 7 of this Section II.

(3) Salaries of First Level Supervisors in the field.

(4) Salaries and wages of Technical Employees directly employed on the Joint Property if such charges are excluded from the Overhead rates.

(5) Salaries and wages of Technical Employees either temporarily or permanently assigned to and directly employed in the operation of the Joint Property if such charges are excluded from the overhead rates.

COPAS 1995 Model Form Accounting Procedure

III. 2. LABOR

Salaries and wages of the Operator's employees directly employed on the Joint Property in the conduct of Joint Operations or while in transit to/from the Joint Property, provided such costs are excluded from the calculation of overhead rates in Section V.

COPAS 1998 Project Team Model Form Accounting Procedure

II. 2. LABOR

A. Salaries and Wages including Incentive Compensation Programs, as set forth in COPAS Interpretation 30, for personnel serving the Joint Property shall be chargeable in accordance with the following provisions.

(1) Project Team

All salaries and wages of employees of the Operator and Non-Operator assigned to the Project Team on a full-time or part-time basis shall be considered a direct cost and shall be charged to the Joint Account. Such employees shall include personnel who are directly engaged in project management, evaluation, design, construction, and installation activities regardless of location. Part-time Project Team personnel specifically assigned to the Project Team shall be charged to the Joint Account, based on actual days worked, only when such time involves at least one full-day equivalent per month that is devoted to the project. Technical Employees not assigned to the Project Team but working under the direction of the Project Team shall be charged to the Joint Account based on actual days worked, only when such time involves at least one full-day equivalent per month. Contractor and Affiliate charges for personnel assigned to the Project Team are chargeable pursuant to Section II, Paragraphs 5 and 7.

(2) Other Operations—Non-Project Team

The following salaries and wages shall be charged for employees:

(a) Salaries and wages of the Operator's field employees directly employed on the Joint Property in the conduct of Joint Operations
(b) Salaries and wages of the Operator's employees directly employed on Shore Base Facilities or other Offshore Facilities serving the Joint Property if such costs are not charged under Paragraph 6 of this Section II
(c) Salaries of First Level Supervisors
(d) Salaries and wages of Technical Employees directly employed on the Joint Property in the conduct of Joint Operations, or on Offshore Facilities serving the Joint Property, if such charges are excluded from the Overhead rates
(e) Salaries and wages of Technical Employees either temporarily or permanently assigned to and directly employed in the operation of the Joint Property if such charges are excluded from the overhead rates

II. 13. ECOLOGICAL, ENVIRONMENTAL, AND SAFETY

A. Ecological and Environmental costs incurred

- ☐ for the benefit of the Joint Property
- ☐ on the Joint Property

resulting from laws, rules, regulations, or orders for archaeological and geophysical surveys relative to identification and protection of cultural resources and/or other environmental or ecological surveys as may be required by the Minerals Management Service or other regulatory authority. Also, costs to provide or have available pollution containment and removal equipment plus actual costs of control and cleanup and resulting responsibilities of oil and other spills as well as discharges from permitted outfalls as required by applicable laws and regulations are chargeable. Ecological and environmental costs incurred by the Operator as deemed by the Operator to be appropriate for prudent operations are also chargeable to the extent such costs directly benefit Joint Operations.

B. Safety costs incurred

- ☐ for the benefit of the Joint Property
- ☐ on the Joint Property

to conduct and/or implement safe operational practices/guidelines as a result of laws, rules, regulations, or orders or as recommended for voluntary compliance. Examples are the requirements mandated by the Occupational Safety and Hazards Act (OSHA), Safety and Environmental Management Program (SEMP), Process Safety Management (PSM), and/or requirements which may be mandated/recommended by similar programs or by other current or successor regulatory agencies. Safety costs incurred by the Operator as deemed by the Operator to be appropriate for prudent operations are also chargeable to the extent such costs directly benefit Joint Operations.

<u>COPAS 2005 Model Form Accounting Procedure</u>

II. 2. LABOR

A. Salaries and wages, including incentive compensation programs as set forth in COPAS MFI-37 (“Chargeability of Incentive Compensation Programs”), for:

(1) Operator’s field employees directly employed On-site in the conduct of Joint Operations,

(2) Operator’s employees directly employed on Shore Base Facilities, Offshore Facilities, or other facilities serving the Joint Property if such costs are not charged under Section II.6 (*Equipment and Facilities Furnished by Operator*) or are not a function covered under Section III (*Overhead*),

(3) Operator’s employees providing First Level Supervision,

(4) Operator's employees providing On-site Technical Services for the Joint Property if such charges are excluded from the overhead rates in Section III (*Overhead*),

(5) Operator's employees providing Off-site Technical Services for the Joint Property if such charges are excluded from the overhead rates in Section III (*Overhead*).

Charges for the Operator's employees identified in Section II.2.A may be made based on the employee's actual salaries and wages, or in lieu thereof, a day rate representing the Operator's average salaries and wages of the employee's specific job category.

Charges for personnel chargeable under this Section II.2.A who are foreign nationals shall not exceed comparable compensation paid to an equivalent U.S. employee pursuant to this Section II.2, unless otherwise approved by the Parties pursuant to Section I.6.A (*General Matters*).

Note: MFI-37 is now titled *Incentive Compensation Costs*.

<u>COPAS Deepwater Model Form Accounting Procedure</u>

II. 2. LABOR

A. Salary and wages, including incentive compensation programs, for:

(1) Feasibility Team and Project Team

Employees of the Operator and Non-Operator, including secondees, assigned to a Feasibility Team or Project Team on a full-time or part-time basis shall be charged directly to the Joint Account. Personnel assigned to a Feasibility Team or Project Team on a part-time basis shall be charged to the Joint Account based on actual time worked. Employees not assigned to a Feasibility Team or Project Team but providing Technical Services and working under the direction of a Feasibility Team or Project Team shall be charged to the Joint Account based on actual time worked. Charges for contractor and Affiliate personnel assigned to or working at the direction of a Feasibility Team or Project Team are governed by Section II.5 (*Services*) or Section II.7 (*Affiliate Services*), as applicable.

(2) Operations Other than Feasibility Team or Project Team

For the following individuals engaged in activities and operations other than those of a Feasibility Team or Project Team, Operator shall charge:

(i) field employees directly employed in the conduct of Joint Operations,
(ii) employees providing First Level Supervision,
(iii) employees providing Technical Services in the conduct of Joint Operations, and

(iv) other employees directly employed On-site in the conduct of Joint Operations if such costs are not included in rates charged under Section II.6 (*Equipment and Facilities Furnished by Parties, Affiliates*) and are not a function covered under Section III (*Overhead*).

For clarification, if the Parties do not form a Project Team and the Operator or another Party prepares a Development Plan that receives approval under the Agreement, the labor costs directly chargeable to the Joint Account to generate and submit the approved Development Plan shall be limited to Technical Services.

Charges for the employees identified in Section II.2.A shall be based on the employee's actual salaries and wages, or in lieu thereof, a day rate representing the employer's average salaries and wages of the employee's specific job category.

II. 7. AFFILIATE SERVICES

Affiliate services provided for the Joint Operations shall be charged to the Joint Account under this Section II.7.

A. Affiliate Costs Associated with a Project

This Section II.7.A applies to charges for services of any Affiliate employees:

i. assigned to a Feasibility Team or Project Team on a full-time or part-time basis, or
ii. not assigned to a Feasibility Team or Project Team but providing Technical Services and working under the direction of the Feasibility Team or Project Team, or
iii. engaged in an activity or operation costing in excess of the Operator's expenditure limit in the Agreement, and requiring approval under the Agreement, or an activity or operation that costs in excess of such expenditure limit and would require approval were it not for the discretionary authority granted the Operator under the Agreement, provided the Affiliate employee is not performing functions covered by Section III (*Overhead*).

A Party wanting to provide Affiliate services for Joint Operations shall notify the other Parties, prior to using its Affiliate, of (i) the name of the Affiliate and services to be provided by it, and (ii) the costs, rates or basis for charges by such Affiliate; provided, however, prior notification shall not be required to use Affiliate services in emergency situations that pose an imminent threat to life, safety, property or the environment. Subject to Section II.7.C, Affiliate services may be charged using either of the following methods:

1. Cost Basis

Affiliate services shall be charged to the Joint Account as charged by the Affiliate to the Party providing such Affiliate services ("Cost Basis"), subject to Section II.7.D *(Affiliate Cost Limitations)*. Cost Basis rates may include, but are not limited to, the Affiliate employee's salaries and wages, payroll burden and benefits, office, computer and other support costs.

2. Negotiated Rate Basis

Affiliate services shall be charged to the Joint Account at rates approved by the Parties pursuant to Section I.6 (*Approval by Parties*). If the Parties are unable to agree upon a rate, the Parties shall use the Cost Basis. As part of the approval under Section I.6, the Parties shall determine the period such Affiliate rates shall remain in effect and the method and frequency of any rate adjustments, if applicable. If the Parties agree on a rate, but are unable to agree upon a method for adjusting the rate, such rate shall be adjusted annually, on the first day of April each year following the effective date of such rates. The adjusted rate shall be the rate originally agreed to by the Parties, increased or decreased, cumulatively, by the overhead adjustment factors published by COPAS for each year following the effective date of the rate.

If the rates are determined to be insufficient or excessive, any Party may request adjustments to an Affiliate's rates at any time it deems appropriate, but the rates shall not be adjusted more than once per year for a given Affiliate. The Parties shall respond to proposals to revise the Affiliate rates within the time prescribed in the Agreement for general voting matters. Approval of a proposed Affiliate's rates and any requested adjustments shall be determined in accordance with the provisions of Section I.6 *(Approval by Parties)* and shall not be unreasonably withheld by the Parties.

B. Affiliate Costs not Associated with a Project

Charges for Affiliate services not associated with a project under Section II.7.A, and not a function covered by Section III (*Overhead*), may be made without the approval of the Parties, provided that the total charges for such Affiliate's services do not exceed ________________ dollars ($________________) per annum. Charges exceeding this threshold shall require approval of the Parties pursuant to Section I.6.A (*General Matters)*. In the case of Affiliate services that are below the threshold in this Section II.7.B, the basis of the charges shall be on the Cost Basis, unless otherwise agreed to by the Parties. If the Parties fail to designate an amount in this Section II.7.B, the amount deemed adopted by the Parties as a result of such omission shall be the amount established as the Operator's expenditure limit in the Agreement.

EXHIBIT 2: SERVICES

COPAS 1962 Model Form Accounting Procedure

II. 6. Services

A. The cost of contract services and utilities procured from outside sources other than services covered by Paragraph 8 of this Section II and Paragraph 2 of Section III.

B. Use and service of equipment and facilities furnished by Operator as provided in Paragraph 5 of Section IV.

COPAS 1968 Model Form Accounting Procedure

II. 6. Services

A. The cost of contract services and utilities procured from outside sources other than services covered by Paragraph 8 of this Section II and Paragraph 1.B of Section III. The cost of professional consultant services shall not be charged to the Joint Account unless agreed to by the Operator and Non-operator.

B. Use and service of equipment and facilities furnished by Operator as provided in Paragraph 5 of Section IV.

COPAS 1974 Model Form Accounting Procedure

II. 6. Services:

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 9 of Section II and Paragraph I of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the Overhead rates. The cost of professional consultant services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

COPAS 1976 Offshore Model Form Accounting Procedure

II. 6. Services

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 9 of Section II and Paragraph I of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the Overhead rates. The cost of professional consultant services or contract services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

COPAS 1984 Model Form Accounting Procedure

II. 7. SERVICES

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 10 of Section II and Paragraph i, ii, and iii, of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the overhead rates. The cost of professional consultant services or contract services of technical personnel not directly engaged on the Joint Property shall not be charged to the Joint Account unless previously agreed to by the Parties.

COPAS 1986 Offshore Model Form Accounting Procedure

II. 6. Services

The cost of contract services, equipment and utilities provided by outside sources, except services excluded by Paragraph 9 of Section II and Paragraphs i and ii of Section III. The cost of professional consultant services and contract services of technical personnel directly engaged on the Joint Property if such charges are excluded from the overhead rates. The cost of professional consultant services or contract services of technical personnel directly engaged in the operation of the Joint Property shall be charged to the Joint Account if such charges are excluded from the overhead rates.

COPAS 1995 Model Form Accounting Procedure

III. 5. SERVICES

The cost of contract services, equipment, and utilities provided by sources other than the Operator.

COPAS 1998 Project Team Model Form Accounting Procedure

II. 5. SERVICES

The cost of contract services, equipment, and utilities used in the conduct of Joint Operations and provided by sources other than the Parties, except for contract services, equipment, and utilities covered by the Section III overhead provisions, Paragraph 7 of this Section II, or excluded under Paragraph 9 of this Section II. Notwithstanding anything herein to the contrary, the cost of contract personnel assigned to the Project Team are directly chargeable to the Joint Account.

COPAS 2005 Model Form Accounting Procedure

II. 5. SERVICES

The cost of contract services, equipment, and utilities used in the conduct of Joint Operations, except for contract services, equipment, and utilities covered by Section III (Overhead), or Section II.7 (Affiliates), or excluded under Section II.9 (Legal Expense). Awards paid to contractors shall be chargeable pursuant to COPAS MFI-49 ("Awards to Employees and Contractors").

The costs of third party Technical Services are chargeable to the extent excluded from the overhead rates under Section III (Overhead).

Note: MFI-49 is now titled *Employee and Contractor Awards.*

COPAS Deepwater Model Form Accounting Procedure

II. 5. SERVICES

The cost of services provided by third parties, including Technical Services provided in the conduct of Joint Operations, but excluding services covered by Section II.7 (*Affiliate Services*), Section II.9 (*Legal Expense*), or Section III (*Overhead*). The cost of awards to third parties shall be chargeable to the Joint Account (i) if such third parties are chargeable under this Section II.5, and (ii) to the extent such awards pertain to services provided for activities or operations conducted under the Agreement. The cost of operational, technical, HSE or government-mandated training shall be chargeable to the Joint Account, for third parties who are chargeable under this Section II.5.

II. 7.

C. Affiliate Charges – Other Provisions

Third-party contract services provided by an Affiliate shall be charged pursuant to Section II.5 (Services), and shall not include any mark-up or purchasing fee for Affiliate unless approved by the other Parties pursuant to Section I.6 (Approval by Parties).

EXHIBIT 3: EQUIPMENT AND FACILITIES FURNISHED BY OPERATOR

COPAS 1962 Model Form Accounting Procedure

IV. 5. Equipment and Facilities Furnished by Operator

A. Operator shall charge the Joint Account for use of equipment and facilities at rates commensurate with cost of ownership and operation. Such rates shall include cost of maintenance, repairs, other operating expense, insurance, taxes, depreciation and interest on investment not to exceed six per cent (6%) per annum, provided such rates shall not exceed those currently prevailing in the immediate area within which the Joint Property is located. Rates for automotive equipment shall generally be in line with the schedule of rates adopted by the Petroleum Motor Transport Association, or some other recognized organization, as recommended uniform charges against Joint Property operations. Rates for laboratory services shall not exceed those currently prevailing if performed by outside service laboratories. Rates for trucks, tractors and well service units may include wages and expenses of Operator.

B. Whenever requested, Operator shall inform Non-Operators in advance of the rates it proposes to charge.

C. Rates shall be revised and adjusted from time to time when found to be either excessive or insufficient.

COPAS 1968 Model Form Accounting Procedure

IV. 5. Equipment and Facilities Furnished by Operator

A. Operator shall charge the Joint Account for use of equipment and facilities at rates commensurate with cost of ownership and operation. Such rates shall include cost of maintenance, repairs, other operating expense, insurance, taxes, depreciation, and interest on investment not to exceed six per cent (6%) per annum, provided such rates shall not exceed those currently prevailing in the immediate area within which the Joint Property is located. In lieu of rates based on costs of ownership and operation of equipment other than automotive, Operator may elect to use commercial rates prevailing in the area of the Joint Property less 20%; for automotive equipment rates as published by the Petroleum Motor Transport Association may be used. Rates for laboratory services shall not exceed those currently prevailing if performed by outside service laboratories. Rates for trucks, tractors and well service units may include wages and expenses of operator.

B. Whenever requested, Operator shall inform Non-Operators in advance of the rates it proposes to charge.

C. Rates shall be revised and adjusted from time to time when found to be either excessive or insufficient.

COPAS 1974 Model Form Accounting Procedure

II. 7. Equipment and Facilities Furnished by Operator

A. Operator shall charge the Joint Account for use of owned equipment and facilities at rates commensurate with costs of ownership and operation. Such rates shall include costs of maintenance, repairs, other operating expense, insurance, taxes, depreciation and interest on investment not to exceed eight percent (8%) per annum. Such rates shall not exceed average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in Paragraph 7A above, Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property less 20%. For automotive equipment, Operator may elect to use rates published by the Petroleum Motor Transport Association.

COPAS 1976 Offshore Model Form Accounting Procedure

II. 7. Equipment and Facilities Furnished by Operator

A. Operator shall charge the Joint Account for use of Operator-owned equipment and facilities, including Shore Base and/or Offshore Facilities, at rates commensurate with costs of ownership and operation. Such rates may include labor, maintenance, repairs, other operating expense, insurance, taxes, depreciation and interest on depreciated investment not to exceed eight percent (8%) per annum. In addition, for platforms only, the rate may include an element of the estimated cost of platform dismantlement. Such rates shall not exceed average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In Lieu of charges in Paragraph 7A above, Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property less twenty percent (20%). For automotive equipment, Operator may elect to use rates published by the Petroleum Motor Transport Association.

COPAS 1984 Model Form Accounting Procedure

II. 8. EQUIPMENT AND FACILITIES FURNISHED BY OPERATOR

A. Operator shall charge the Joint Account for use of Operator owned equipment and facilities at rates commensurate with costs of ownership and operation. Such rates shall include costs of maintenance, repairs, other operating expense, insurance, taxes, depreciation, and interest on gross investment less accumulated depreciation not to exceed _______ percent (_____%) per annum. Such rates shall not exceed average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in paragraph 8A above, Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property less

20%. For automotive equipment, Operator may elect to use rates published by the Petroleum Motor Transport Association.

COPAS 1986 Offshore Model Form Accounting Procedure

II. 7. Equipment and Facilities Furnished by Operator

A. Operator shall charge the Joint Account for use of Operator-owned equipment and facilities, including Shore Base and/or Offshore Facilities, at rates commensurate with costs of ownership and operation. Such rates may include labor, maintenance, repairs, other operating expense, insurance, taxes, depreciation and interest on gross investment less accumulated depreciation not to exceed________percent (_____%) per annum. In addition, for platforms only, the rate may include an element of the estimated cost of platform dismantlement. Such rates shall not exceed average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in Paragraph 7A above, Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property less twenty percent (20%). For automotive equipment, Operator may elect to use rates published by the Petroleum Motor Transport Association.

COPAS 1995 Model Form Accounting Procedure

III. 6. EQUIPMENT FURNISHED BY THE OPERATOR

A. Equipment located on the Joint Property owned by the Operator shall be charged to the Joint Account at the average prevailing commercial rate for such equipment. If an average commercial rate is used to bill the Joint Account, the Operator shall adequately document and support such rate and shall periodically review and update the rate.

B. In lieu of charges in Paragraph 6.A. above, or if a prevailing commercial rate is not available, equipment owned by the Operator will be charged to the Joint Account at the Operator's actual cost. Such costs may include all expenses that would be chargeable pursuant to this Section III if such equipment were jointly owned, depreciation using straight line depreciation method, interest on investment (less gross accumulated depreciation) not to exceed ___% per annum, and an element of the estimated costs to dismantle and abandon the equipment. Charges for depreciation will no longer be allowable once the equipment has been fully depreciated. Actual cost shall not exceed the average prevailing commercial rate.

C. When applicable for Operator-owned or -leased motor vehicles, the Operator shall use rates published by the Petroleum Motor Transport Association or such other organization recognized by COPAS as the official source of such rates. When such rates are not available, the Operator shall comply with the provisions of Paragraph A or B above.

COPAS 1998 Project Team Model Form Accounting Procedure

II. 6. EQUIPMENT AND FACILITIES FURNISHED BY OPERATOR

In the absence of a separately negotiated agreement, equipment and facilities furnished by the Operator will be charged as follows:

A. Equipment and facilities owned by the Operator shall be charged to the Joint Account at the average prevailing commercial rate for such equipment. If an average commercial rate is used to bill the Joint Account, the Operator shall adequately document and support such rate and shall periodically review and update the rate and the supporting documentation.

B. In lieu of charges in Paragraph 6.A. above, or if a prevailing commercial rate is not available, equipment and facilities owned by the Operator will be charged to the Joint Account at the Operator's actual cost. Such costs shall be limited to expenses that would be chargeable pursuant to this Section II if such equipment and facilities were jointly owned, depreciation using straight line depreciation method, and interest on investment (less gross accumulated depreciation) not to exceed ___% per annum. In addition, for platforms, subsea production systems, and production handling facilities, the rate may include an element of the estimated cost of abandonment, reclamation, and dismantlement. Depreciation shall not be charged when the equipment and facilities investment have been fully depreciated. Charges shall not exceed the average prevailing commercial rate, if available.

COPAS 2005 Model Form Accounting Procedure

II. 6. EQUIPMENT AND FACILITIES FURNISHED BY OPERATOR

In the absence of a separately negotiated agreement, equipment and facilities furnished by the Operator will be charged as follows:

A. Operator shall charge the Joint Account for use of Operator-owned equipment and facilities, including but not limited to production facilities, Shore Base Facilities, Offshore Facilities, and Field Offices, at rates commensurate with the costs of ownership and operation. The cost of Field Offices shall be chargeable to the extent the Field Offices provide direct service to personnel who are chargeable pursuant to Section II.2.A (*Labor*). Such rates may include labor, maintenance, repairs, other operating expense, insurance, taxes, depreciation using straight line depreciation method, and interest on gross investment less accumulated depreciation not to exceed _____ percent (__%) per annum; provided, however, depreciation shall not be charged when the equipment and facilities investment have been fully depreciated. The rate may include an element of the estimated cost for abandonment, reclamation, and dismantlement. Such rates shall not exceed the average commercial rates currently prevailing in the immediate area of the Joint Property.

B. In lieu of charges in Section II.6.A above, the Operator may elect to use average commercial rates prevailing in the immediate area of the Joint Property, less twenty percent (20%). If equipment and facilities are charged under this Section II.6.B, the Operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation. For automotive equipment, the Operator may elect to use rates published by the Petroleum Motor Transport Association (PMTA) or such other organization recognized by COPAS as the official source of rates.

COPAS Deepwater Model Form Accounting Procedure

II. 6. EQUIPMENT AND FACILITIES FURNISHED BY PARTIES, AFFILIATES

Operator shall charge the Joint Account for use of equipment and facilities which are owned in whole or in part by a Party or its Affiliates, and used to conduct Joint Operations, including, but not limited to, Shore Base Facilities, Offshore Facilities, Remote Technology Centers, warehouses used to store Joint Property, Operations Offices and other facilities used to conduct Joint Operations; provided, however, the cost of Operations Offices shall be chargeable only to the extent the Operations Offices provide direct service to personnel who are chargeable pursuant to Sections II.2.A (*Labor*), Section II.5 (*Services*) or Section II.7 (*Affiliate Services*), as applicable.

The costs of purchasing, installing, operating, repairing, maintaining, dismantling, and abandoning communication facilities or systems, including satellite, radio and microwave facilities, and fiber optics cable systems, directly supporting joint operations shall be charged under this Section II.6, regardless of whether wholly or partially owned by a Party or its Affiliate.

The costs of purchasing, installing, operating, repairing, maintaining, dismantling, and abandoning computer systems, including hardware, software and data storage directly supporting joint operations shall be charged under this Section II.6, regardless of whether wholly or partially owned by a Party or its Affiliate.

In the absence of a separately negotiated agreement, equipment and facilities furnished by a Party or its Affiliate will be charged as follows:

A. Charges for use of such equipment and facilities shall be made at rates commensurate with the cost of ownership and operation. Such rates may include labor, maintenance, repairs, other operating expense, insurance, taxes, and depreciation using straight line depreciation method, and interest on gross investment less accumulated depreciation, not to exceed ______ percent (__%)

per annum; provided, however, depreciation shall not be charged when the equipment and facilities investment has been fully depreciated. The rate may include an element of the estimated cost for abandonment, reclamation, and dismantlement. Such rates shall not exceed the commercial rates currently prevailing for deepwater Gulf of Mexico operations.

In lieu of charges in Section II.6.A, the operator may elect to use average commercial rates prevailing for Deepwater Gulf of Mexico operations. If equipment and facilities are charged under this Section II.6.B, the operator shall adequately document and support commercial rates and shall periodically review and update the rate and the supporting documentation. For automotive equipment, the operator may elect to use rates published by the Petroleum Motor Transport Association (PMTA) or such other organization recognized by COPAS as an acceptable source of rates.

A. Operator may charge the joint account an allocated portion of Rig-Related Costs for drillships or rigs used in joint operations provided such costs are not included in the drillship or rig rate charged by the drilling contractor.

EXHIBIT 4: PERSONAL EXPENSES

COPAS 1962 Model Form Accounting Procedure

II. 2.

D. Reasonable personal expenses of those employees whose salaries and wages are chargeable to the joint account under Paragraph 2A of this Section II and for which expenses the employees are reimbursed under operator's usual practice.

COPAS 1968 Model Form Accounting Procedure

II. 2.

D. Reasonable personal expenses of those employees whose salaries and wages are chargeable to the joint account under Paragraph 2A of this Section II and for which expenses the employees are reimbursed under the operator's usual practice.

COPAS 1974 Model Form Accounting Procedure

II. 2.

D. Personal Expenses of those employees whose salaries and wages are chargeable to the joint account under Paragraph 2A of this Section II.

COPAS 1984 Model Form Accounting Procedure

II. 3.

D. Personal Expenses of those employees whose salaries and wages are chargeable to the joint account under Paragraph 3A of this Section II.

COPAS 1986 Offshore Model Form Accounting Procedure

II. 2.

D. Personal Expenses of those employees whose salaries and wages are chargeable to the joint account under Paragraph 2A of this Section II.

COPAS 1995 Model Form Accounting Procedure

III. 2.

C. Reimbursable travel, meals, and lodging of these employees.

COPAS 1998 Project Team Model Form Accounting Procedure

II .2.

D. Personal Expenses, other than relocation costs, of personnel whose salaries and wages are chargeable to the joint account under Paragraph 2.A of this Section II

COPAS 2005 Model Form Accounting Procedure

II. 2.

D. Personal Expenses of personnel whose salaries and wages are chargeable to the joint account under Section II.2.A when the expenses are incurred in connection with directly chargeable activities.

COPAS Deepwater Model Form Accounting Procedure

II. 2.

D. Personal Expenses of personnel whose salaries and wages are chargeable to the joint account under Section II.2.A when the expenses are incurred in connection with directly chargeable activities; provided, however, relocation costs that (i) result from reorganization or merger of a Party, or that are for the primary benefit of the operator, or non-operator, as applicable, or (ii) are for personnel assigned to joint operations for less than twelve (12) consecutive months, shall not be chargeable unless agreed to by the Parties pursuant to Section I.6 (*Approval by Parties*).

II. 7.

C. Affiliate charges - Other Provisions
Affiliate employee charges related to Personal Expenses, training, and awards shall be made in the same manner as provided for employees in Sections II.2.D, II.2.E, and II.2.G.

EXHIBIT 5: TRAINING COSTS

COPAS 1962 Model Form Accounting Procedure

Training is not specifically addressed.

II. 11. Other Expenditures
Any other expenditure not covered or dealt with in the foregoing provisions of this Section II or in Section III and which is incurred by the operator for the necessary and proper conduct of the joint operations.

COPAS 1968 Model Form Accounting Procedure

Training is not specifically addressed.

II. 11. Other Expenditures
Any other expenditure not covered or dealt with in the foregoing provisions of this Section II or in Section III and which is incurred by the operator for the necessary and proper conduct of the joint operations.

COPAS 1974 Model Form Accounting Procedure

Training is not specifically addressed.

II. 12. Other Expenditures
Any other expenditure not covered or dealt with in the foregoing provisions of this Section II, or in Section III, and which is incurred by the operator in the necessary and proper conduct of the joint operations.

COPAS 1976 Offshore Model Form Accounting Procedure

Training is not specifically addressed.

II. 14 OTHER EXPENDITURES
Any other expenditure not covered or dealt with in the foregoing provisions of this Section II, or in Section III, and which is incurred by the operator in the necessary and proper conduct of the joint operations.

COPAS 1984 Model Form Accounting Procedure

Training is not specifically addressed.

II. 15 OTHER EXPENDITURES

Any other expenditure not covered or dealt with in the foregoing provisions of this Section II, or in Section III and which is of direct benefit to the joint property and is incurred by the operator in the necessary and proper conduct of the joint operations.

COPAS 1986 Offshore Model Form Accounting Procedure

Training is not specifically addressed.

15. Other Expenditures

Any other expenditure not covered or dealt with in the foregoing provisions of this Section II, or in Section III and which is of direct benefit to the joint property and is incurred by the operator in the necessary and proper conduct of the joint operations.

COPAS 1995 Model Form Accounting Procedure

III. 2.

D. Government-mandated training. This training charge shall include the wages, salaries, training course cost, and reimbursable travel, meals, and lodging incurred during the training session. The cost of the training course will be limited to prevailing commercial rates.

IV. 4. TRAINING

Training mandated by governmental authorities for those employees who would be chargeable to the joint account under Section III, Paragraph 2, of this Accounting Procedure if they were not attending the training shall be chargeable to the joint account. This training charge shall include costs as defined in Section III, Paragraph 2.D., but incurred off the joint property.

COPAS 1998 Project Team Model Form Accounting Procedure

II. 2.

E. Training costs shall be chargeable as specified in COPAS Interpretation 27 and as provided in Section II, Paragraph 13. This training charge shall include the wages, salaries, training course cost, and Personal Expenses incurred during the training session for personnel to the extent their salaries and wages are chargeable under Paragraph 2.A of this Section II. The cost of the training course will be limited to prevailing commercial rates where available.

II. 13.

C. Environmental, ecological, and safety training costs for personnel whose time would otherwise be chargeable under Paragraph 13.A or B above, regardless of whether training is mandated by statute or regulatory agency, is chargeable to the joint account.

Note: "COPAS Interpretation 27" is now MFI-35, *Employee and Contractor Training Costs.*

COPAS 2005 Model Form Accounting Procedure

II. 2.

F**.** Training costs as specified in COPAS MFI-35 ("Charging of Training Costs to the joint account") for personnel whose salaries and wages are chargeable under Section II.2.A. This training charge shall include the wages, salaries, training course cost, and Personal Expenses incurred during the training session. The training cost shall be charged or allocated to the property or properties directly benefiting from the training. The cost of the training course shall not exceed prevailing commercial rates, where such rates are available.

Note: MFI-35 is now titled *Employee and Contractor Training Costs.*

COPAS Deepwater Model Form Accounting Procedure

II. 2.

E. The cost of operational, technical, HSE or government-mandated training for personnel whose salaries and wages are chargeable under Section II.2.A. This training charge shall include the wages, salaries, payroll burden and benefits, training course cost, and Personal Expenses incurred during the training. Such training cost shall be charged on a pro-rata basis to all properties directly benefiting from the training. The cost of the training course shall not exceed prevailing commercial rates, when such rates are available.

II. 7.

C. Affiliate charges - Other Provisions
Affiliate employee charges related to Personal Expenses**,** training, and awards shall be made in the same manner as provided for employees in Sections II.2.D, II.2.E, and II.2.G.

EXHIBIT 6: SAMPLE OPERATING AGREEMENT PROVISIONS AFFECTING TRAINING

There are numerous other industry model form joint operating agreements ("JOAs"), but it is not practical to list them all. Generally speaking, the model form JOAs have "boilerplate provisions" that grant the operator broad authority to hire employees and contractors and establish job responsibilities. The JOAs also require the operator to comply with laws, and there are various state and federal requirements pertaining to job safety and training. Readers should consult with appropriate HSE/regulatory/legal personnel for more information on training required by law or regulations for a given property.

AAPL 610-1982

Article V.A Designation and Responsibilities of Operator
_________ shall be the operator of the Contract Area, and shall conduct and direct and have full control of all operations on the Contract Area as permitted and required by, and within the limits of this agreement. It shall conduct all such operations in a good and workmanlike manner, but shall have no liability as operator to the other parties for losses sustained or liabilities incurred, except such as may result from gross negligence or willful misconduct.

Article V.C Employees
The number of employees used by operator in conducting operations hereunder, their selection, and the hours of labor and the compensation for services performed shall be determined by operator, and all such employees shall be the employees of operator.

Article XIV.A Laws, Regulations and Orders
The agreement shall be subject to the conservation laws of the state in which the Contract Area is located, to the valid rules, regulations, and orders of any duly constituted regulatory body of said state; and to all other applicable federal, state and local laws, ordinances, rules, regulations, and orders.

AAPL 610-1989

Article V.A Designation and Responsibilities of Operator
_________ shall be the operator of the Contract Area, and shall conduct and direct and have full control of all operations on the Contract Area as permitted and required by, and within the limits of this agreement. In its performance of services hereunder for the non-operators, operator shall be an independent contractor, not subject to the control or director of the non-operators except as to the type of operation to be undertaken in accordance with the election procedures contained this agreement. Operator shall not be deemed, or hold itself out as, the agent of the non-operators with the authority to bind them to any obligation or liability assumed or incurred by operator at to any third party. Operator shall conduct its activities under this agreement as a reasonable prudent operator, in a good and workmanlike manner, with due diligence and dispatch, in accordance with good oilfield practice, and in compliance with applicable law and regulation, but in no event shall

it have any liability as operator to the other parties for losses sustained or liabilities incurred, except such as may result from gross negligence or willful misconduct.

Article V.C Employees and Contractors
The number of employees or contractors used by operator in conducting operations hereunder, their selection, and the hours of labor and the compensation for services performed shall be determined by operator, and all such employees or contractors shall be the employees or contractors of operator.

Article XIV.A Laws, Regulations and Orders
The agreement shall be subject to the applicable laws of the state in which the Contract Area is located, to the valid rules, regulations, and orders of any duly constituted regulatory body of said state; and to all other applicable federal, state and local laws, ordinances, rules, regulations, and orders.

<u>AAPL 710-2002</u>

5.2 Workmanlike Conduct
Operator shall timely commence and conduct all operations in a good and workmanlike manner, as would a prudent operator under the same or similar circumstances. OPERATOR SHALL NOT BE LIABLE TO NON-OPERATORS FOR LOSSES SUSTAINED OR LIABILITIES INCURRED, EXCEPT AS MAY RESULT FROM OPERATOR'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. Operator shall never be required under this Agreement to conduct an operation that it believes would be unsafe or would endanger persons, property or the environment. Unless otherwise provided in this Agreement, operator shall consult with non-operators and keep them informed of all important matters.

5.4 Employees and Contractors
Operator shall select employees and contractors and determine their number, hours of labor, and compensation. The employees shall be employees of operator.

5.6 Compliance
Operator shall comply, and shall require all agents and contractors to comply, with all applicable laws, rules, regulations, and orders of governmental authorities having jurisdiction.

5.7 Contractors
Operator may enter into contracts with qualified and responsible independent contractors for the design, construction, installation, drilling, production or operation of wells, Platforms and Development Facilities. Insofar as possible, operator shall use competitive bidding to procure goods and services for the benefit of the Parties. All drilling operations conducted under this Agreement shall be conducted by properly qualified and responsible drilling contractors under current competitive contracts.

8.3 Emergency and Required Expenditures
Notwithstanding anything in this Agreement to the contrary, operator is hereby authorized to conduct operations and incur expenses that in its opinion are reasonably necessary to safeguard life, property, and the environment in case of an actual or imminently threatened blowout, explosion, accident, fire, flood, storm, hurricane, catastrophe, or other emergency, and the expenses shall be borne by the Participating Parties in the affected operation. Operator shall report to the Participating Parties, as promptly as possible, the nature of the emergency and the action taken. Operator is also authorized to conduct operations and incur expenses reasonably required by statute, regulation, order, or permit condition or by a governmental authority having jurisdiction, which expenses shall be borne by the Participating Parties in the affected operation, subject to Exhibit "C."

AAPL 810-2007

5.1 Exclusive Right to Operate
Except as otherwise provided, the operator has the exclusive right and duty to conduct (or cause to be conducted) all activities or operations under this Agreement. In performing services under this Agreement for the Non-Operating Parties, the operator is an independent contractor, not subject to the control or direction of Non-Operating Parties, except as provided in Article 8.2 *(Voting and Election Procedures)* or Article 8.5 *(Approved by Unanimous Agreement)*. The operator is not the agent or fiduciary of the Non-Operating Parties. With the exception of any Feasibility Team or Project Team formed under this Agreement, the operator shall select and determine the number of employees, Affiliates, contractors, and/or consultants used in conducting activities or operations under this Agreement and the hours of labor and the compensation for those employees, Affiliates, contractors, and/or consultants. All of those employees, Affiliates, contractors, and/or consultants shall be the employees, Affiliates, contractors, and/or consultants of the operator. The operator shall contract for and employ any drilling rigs, tools, machinery, equipment, materials, supplies, and personnel reasonably necessary for the operator to conduct the activities or operations provided for in this Agreement; however, if a substitute operator is designated to drill a well, the substitute operator may utilize a rig, which it owns or has under contract, for the drilling of that well.

5.2 Workmanlike Conduct
The operator shall timely commence and conduct all activities or operations in a good and workmanlike manner, as would a prudent operator under the same or similar circumstances. THE OPERATOR SHALL NOT BE LIABLE TO THE NON-OPERATING PARTIES FOR LOSSES SUSTAINED OR LIABILITIES INCURRED, EXCEPT AS MAY RESULT FROM OPERATOR'S GROSS NEGLIGENCE OR WILLFUL MISCONDUCT. UNLESS OTHERWISE PROVIDED IN THIS AGREEMENT, THE OPERATOR SHALL CONSULT WITH THE NON-OPERATING PARTIES AND KEEP THEM INFORMED OF IMPORTANT MATTERS. The operator shall never be required to conduct an activity or operation under this Agreement that it, as a reasonable and prudent operator in similar circumstances, believes would be unsafe or would endanger persons, property, or the environment.

5.3 Drilling Operations

The operator may have drilling operations conducted by qualified and responsible independent contractors who are not an Affiliate of the operator and are employed under competitive contracts.

5.10 Health, Safety Environment

With the goal of achieving safe and reliable activities and operations in compliance with all applicable laws and regulations, including avoiding significant and unintended impact on (i) the health or safety of people, (ii) property, or (iii) the environment, the operator shall, with the support and cooperation of the non-operators, while it conducts activities or operations under this Agreement:

(a) design and manage activities or operations to standards intended to achieve sustained reliability and promote the effective management of HSE risks;

(b) apply structured HSE management systems and procedures consistent with those generally applied in the petroleum industry to effectively manage HSE risks and pursue sustained reliability of operations under this Agreement; and

(c) conform with locally applicable HSE related statutory requirements that may apply.

In fulfilling its duties and obligations hereunder, the operator shall act in accordance with the provisions of Exhibit "K."

Audit Rights of Non-Participating and Non-Consenting Parties

MODEL FORM INTERPRETATION 36

Publication/Revision Date - December 2019

Board Approved

PRUTCOM Approved: January 28, 2025

FOREWORD

This publication was originally published under the guidelines and procedures in existence prior to the revised publication procedure COPAS established in April 1999. The Council approved the re-classification of this publication in its current form based on its content but recognized that it had not received the same approval levels as publications developed and published under the current publication procedures. The actual approval level is noted on the cover page. As with all COPAS publications under the new standards, if this publication is revised or updated, it will also be required to meet the content and approval standards of the current COPAS publication process prior to issuance.

COPAS MODEL FORM INTERPRETATION 36

ISSUED: July 24, 1997

AUDIT RIGHTS OF NON-PARTICIPATING AND NON-CONSENTING PARTIES

PREFACE

This COPAS Interpretation ("AG") has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest and Audit Standing Committees and has been approved by the Board of Directors of the Council of Petroleum Accountants Societies. It is recommended as a guide in auditing payout and non-consent situations.

PROBLEM

Most joint operating agreements ("JOA") and COPAS model form accounting procedures do not specifically address audits of payout accounts. Rather, the COPAS model form accounting procedures refer to audits of the "Joint Account." COPAS AG-13, *Accounting for Farmouts/Farm-ins, Net Profits Interests and Carried Interests,* discusses the accounting for carried interests and describes guidelines for non-consenting owners, herein referred to as a "non-participant" or "non-consenting party." The guidelines discussed in the "Audit Rights" section of COPAS AG-13, *Accounting for Farmouts/Farm-ins, Net Profits Interests, and Carried Interests,* may differ from the current common industry practice. Moreover, the timing of auditing non-consent situations, as noted in the 1994 COPAS Audit Benchmarking Study, is not consistent throughout the industry between large, medium, and small companies.

This interpretation clarifies the audit rights related to the non-participant's share of expenses for non-consent situations in the absence of specific audit rights in the JOA, accounting procedure, or other agreement between the parties.

INTERPRETATION

Absent any opposing agreement between the parties, the following guidelines should be followed.

Audits of Payouts

Non-consenting parties shall have until 24 months following the end of the calendar year that the operator rendered a payout statement to audit the payout statement.

In the case of payout statements rendered prior to the July 24, 1997, issuance of this Model Form Interpretation, the non-consenting party shall have until December 31, 1999, to take written exception to the payout statement.

The audit rights of non-consenting parties shall be limited to the current period activity represented in the payout statement and shall not include any portion of the cumulative balances on the payout statement for which audit rights have expired.

Non-consenting parties shall adhere to the same audit guidelines and protocol as the participating parties as put forth in the applicable accounting procedure, JOA, and COPAS AG-19, *Expenditure Audit Protocols.*

Adjustments to Payout Statements

Going forward, except as otherwise provided in COPAS MFI-40, *24-Month Adjustment Period for Joint Account Adjustments*, adjustments to payout statement expenditures are limited to two years following the end of the calendar year in which the statement was rendered.

Incentive Compensation Costs

MODEL FORM INTERPRETATION 37

Publication/Revision Date - July 1997

Council Approved

PRUTCOM Approved: January 28, 2025

COPAS MODEL FORM INTERPRETATION 37

ISSUED: July 24, 1997

Incentive Compensation Costs

PREFACE

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest Standing Committee and approved by the Board of Directors of the Council of Petroleum Accountants Societies ("COPAS") and is recommended as a resource in accounting for joint interest operations.

PROBLEM

Many companies are implementing incentive compensation programs ("ICPs") that motivate and reward employees for contributing to the company's success. The ICPs are often based on increases in profitability and/or productivity of a business unit or entire company. ICPs are replacing or supplementing annual merit raises. COPAS model form accounting procedures from 1962 through the present and the associated MFIs provide for salaries and wages to be directly charged to the joint account, whereas the employee benefits provision of COPAS model form accounting procedures and COPAS MFI-27, *Employee Benefits and Percentage Limitation,* include bonuses as part of the employee benefit burden rate. The changing nature of employee compensation has led to a variety of methods being used to charge ICPs. These range from charging the costs directly, to incorporating ICPs within the employee benefits rate, or including as operator's overhead.

INTERPRETATION

ICPs reward employees based on predetermined metrics such as increased production and/or profitability. They are an integral part of salary programs that are designed to motivate employees, increase productivity, and promote teamwork. ICPs may include, but are not limited to, variable pay, pay at risk, pay for performance, and gainsharing. COPAS recommends that ICPs paid in cash be directly charged to the joint account for employees whose salaries and wages are chargeable pursuant to the prevailing accounting procedure/operating agreement, regardless of whether the employee received a merit, cost of living, or general increase. Such programs must be a formally documented policy of the operator.

The direct charge to the joint account for ICPs should be on the same basis that the employee's salary is charged, as described in the applicable accounting procedure attached to the operating agreement. In administering such ICP charges, it is recognized there may be a timing difference between when the ICP is earned and when it is paid to the employees. A number of different accounting methods may be employed in making such charges to the joint account. If an employee is permanently assigned to a particular property or properties, the operator may choose to charge the entire amount in the month in which payment is made to the employee. Another method is to increase the labor burden by a percentage equal to the ICP to spread the award evenly over the entire year to not unduly burden any one month's operating cost for a property. This may be done on a prospective basis to properties served in the year the award is paid, even though it was earned in the prior year. Alternatively, the ICP may be charged in the year it is earned on the basis of forecasts, provided there is reasonable conformity or matching of costs between the ICP forecast and the actual award paid.

These methods may also be employed with respect to drilling and construction personnel, and technical employees whose time is charged to specific properties/projects; however, it is recommended that the ICP be charged prospectively to all properties/projects served. As a result, the ICP is charged only to the extent the employee's salary and wages are directly chargeable to a specific property/project. That portion of their time that is not charged to the joint account and considered as overhead also bears an equitable share of the ICP.

Any of the above methods are acceptable, provided the operator is consistent and reasonable in its application.

COPAS does not recommend directly charging the joint account for ICPs in the form of a royalty, overriding royalty, stock, or stock option. Typically, operating agreements provide that any excess or subsequently created burdens are to be borne solely by the party which created the burden. This would preclude the charging of most royalty or overriding royalty awards. Stock options do not lend themselves to a reasonable method of calculating value.

Turning Energy Into Synergy

Electronic Invoice Documentation Requirements

MODEL FORM INTERPRETATION 41

Publication/Revision Date - December 2019

Board Approved

PRUTCOM Approved: January 28, 2025

FOREWORD

This publication was originally published under the guidelines and procedures in existence prior to the revised publication procedure COPAS established in April 1999. The Council approved the re-classification of this publication in its current form based on its content but recognized that it had not received the same approval levels as publications developed and published under the current publication procedures. The actual approval level is noted on the cover page. As with all COPAS publications under the new standards, if this publication is revised or updated, it will also be required to meet the content and approval standards of the current COPAS publication process prior to issuance.

COPAS MODEL FORM INTERPRETATION 41

ISSUED: January 1997
REVISED: July 1998

Electronic Invoice Documentation Requirements

PREFACE:

This COPAS Model Form Interpretation has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest and Audit Standing Committees and approved by the Board of Directors of the Council of Petroleum Accountants Societies. It is recommended as a guide for documentation of electronic invoices.

PROBLEM:

With the increased use of Electronic Data Interchange ("EDI") by operators to streamline their billing processes, the traditional "paper trail" is being eliminated in many areas. With regards to vendor billings, the electronic data set transmitted is replacing the paper invoice. Currently, EDI invoices contain varying amounts of information depending on:

1) the material or service provided;
2) information requirements of the operator to review and approve the charge;
3) EDI capabilities of the vendor.

An inconsistency among operators regarding information contained on electronic invoices and documentation supporting the vendor's electronic billing has developed due to the differences in information requirements and company policies on the retention of backup documentation, such as work tickets, purchase orders, etc.

INTERPRETATION:

Documentation supporting the charges to the joint property, as referenced in the COPAS model form accounting procedures, and information regarding the company's electronic invoicing system must be provided by the operator to the non-operator conducting the audit of the joint account. This information should contain an overview of the operator's system, controls, reports referencing changes to the original data, and other detail to support the integrity of the data transmission, the verification process, and input requirements of the vendor and/or operator.

In order to validate the charge to the joint property, information normally found on paper invoices for the material or service provided is the minimum requirement for electronic invoices. Examples are:

- Payee Name
- Contract number
- Invoice date
- Invoice Number
- Ship-to location
- Ship-from location
- Shipping date
- Name of person ordering the material/services
- Work ticket number
- Original invoice amount
- Original tax amount
- Item prices (per unit and total)
- Freight amount
- Discount
- Due date
- Location/lease/well
- Charge code

Description (amount of detail on invoice, such as work location, service dates, daily work ticket information, etc., is dependent on the type of material/service provided

In addition to the data input by the vendor, the electronic invoice should include the following information, if available, from the operator's system:

- Receive date
- Receiver name/code
- Review date
- Approver name/code
- Invoice change notification

Procurement Card and Convenience Check Documentation Requirements

MODEL FORM INTERPRETATION 42

Publication/Revision Date - February 10, 1998

Board Approved

PRUTCOM Approved: January 28, 2025

FOREWORD

This publication was originally published under the guidelines and procedures in existence prior to the revised publication procedure COPAS established in April 1999. The Council approved the re-classification of this publication in its current form based on its content but recognized that it had not received the same approval levels as publications developed and published under the current publication procedures. The actual approval level is noted on the cover page. As with all COPAS publications under the new standards, if this publication is revised or updated, it will also be required to meet the content and approval stanards of the current COPAS publication process prior to issuance.

COPAS MODEL FORM INTERPRETATION 42

ISSUED: February 10, 1998

Procurement Card and Convenience Check Documentation Requirements

PREFACE

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest and Audit Standing Committees and approved by the Board of Directors of the Council of Petroleum Accountants Societies. It is recommended as a guide in accounting for joint interest operations.

PURPOSE

The purpose of this MFI is to provide guidelines for an operator to follow when charges originating from the use of a procurement card ("P-Card") or convenience check are made to the joint account. The operator's control processes for documenting and distributing such charges should provide reasonable assurance that P-Card or convenience check purchases result in proper charges to the joint account.

PROBLEM

Changes in the marketplace, technology, and the operator's willingness to accept additional risks have significantly increased the use of credit cards for small-dollar purchases resulting in a concern over adequate support and the appropriateness of such charges to the joint account. Typical purchases include materials and supplies, vehicle maintenance, office supplies, and other small-dollar non-controllable equipment. Examples of areas of concern include the following:

- Ensuring there are no charges to the joint account for items which are recovered by overhead.
- Ensuring the joint account is not charged for vehicle maintenance such as tires or batteries while also charging PMTA rates, which include such costs.
- Allocations for well or lease equipment which should be charged directly to a specific property or project.
- Tracking/documentation of sales/use taxes on purchases.
- Retention of detailed transactions to support the appropriateness of such charges to the joint account (only documentation is a summary invoice from the credit card company).

PROCEDURES EMPLOYED

Operators are using various procedures in the distribution of P-Card or convenience check charges to the joint account. Examples include the following:

- Use of specific cards for a specific type of purchase (e.g., separate cards for safety related, vehicle maintenance, field operating and maintenance cost, etc.). Costs in these pools are either charged directly to a specific location or allocated, as appropriate, to properties served on the basis of well count, etc.

- Use of the same card for all purchases with distribution of cost on the basis of a specific review of receipts at month-end or fixed allocation on some historical experience basis.

INTERPRETATION

Regardless of how the operator uses P-Cards or convenience checks in the business, he or she must ensure there is an audit trail which provides adequate supporting documentation for charges to the joint account. This includes having available for review, if requested by the auditor, the individual receipts (or document images) supporting the specific charges originating from the use of P-Cards or convenience checks. P-Card or convenience check charges processed as Electronic Data Interchange ("EDI") transactions should include complete descriptions of such purchases, including all information available from the original paper version of the transaction. See COPAS MFI-41, *Electronic Invoice Documentation Requirements,* for further guidance regarding information to be furnished for audits of EDI transactions to the joint account. Where allocations are used, the operator should provide the auditor an understanding of the procedures and controls in place that provide reasonable assurance that the charges made to the joint account are appropriate and result in an equitable distribution of the charges to the properties served.

Joint Interest Expenditures Documentation Requirements

MODEL FORM INTERPRETATION 43

Publication Date - October 1999

Council Approved

PRUTCOM Reviewed: January 28, 2025

COPAS MODEL FORM INTERPRETATION 43

ISSUED: February 14, 1990
REVISED: October 15, 1999
Joint Interest Expenditures Documentation Requirements

PREFACE

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accountants Societies through representation on the Audit Standing Committee and Joint Interest Standing Committee and approved by the Board of Directors of the Council of Petroleum Accountants Societies and is recommended as a guide in accounting for joint interest operations.

PROBLEM

The various COPAS model form accounting procedures provide that the operator shall maintain accounts and records relating to the joint account. In addition, these procedures provide the non-operators the right to audit these accounts and records to ensure that the charges/credits to the joint account are proper.

It is the lead auditor's responsibility to identify and communicate to the operator what documentation will be required.

The operator's role in an audit, as provided in COPAS AG-19, *Expenditure Audit Protocols,* includes providing to the auditors documentation support for requested transactions within a reasonable period of time. However, discrepancies can occur when auditors and operators communicate about quality and availability of documentation for audit purposes.

Requested records and complete supporting documentation are not always readily available. Indirectly related or confidential documents that are necessary to ensure that charges/credits to the joint account are proper are sometimes inaccessible and visits to other locations where support documents are maintained are not always allowed. Historically, equipment needed to read and/or reproduce "filmed" or imaged documents was not compatible with the needs of the audit team nor was acceptable documentation available when "filmed" or imaged documents were illegible or questionable.

A need exists to define what constitutes adequate documentation to support the operator's accounts and records relating to the joint account. A need also exists to provide additional clarification related to auditors' and operators' responsibilities related to "documentation supporting joint interest expenditures."

INTERPRETATION

"Adequate documentation" that supports an operator's accounts and records relating to the joint account is defined as documentation which supports and/or otherwise provides credibility that charges/credits to the joint account are proper.

The COPAS model form accounting procedures allow non-operators the right to audit charges/credits to the joint account. In order to conduct the audit, the non-operators, through designated audit representatives, are entitled to review all documents which support joint account transactions.

It is the lead auditor's responsibility to identify and communicate to the operator what information/documentation will be required for review. If requested documents or records are not available, it is the operator's responsibility to provide support to substantiate the transaction. If requested documents or records are only available at another location, the operator should notify the lead auditor well in advance of the commencement of the audit so necessary arrangements can be made for their inspection. Such arrangements will be essential to the timely completion of the fieldwork. The operator should make reasonable attempt to consolidate records to minimize an auditor's visits to multiple locations and interruptions of its own operations. The operator should also make every reasonable effort to obtain requested records or arrange visits to off-site locations during the scheduled fieldwork.

If the auditor is unable to determine that the charge/credit is proper, the operator must provide additional support to substantiate the charge/credit. Examples of additional documentation could include canceled checks, work/field tickets, payroll records, and referenced purchase orders. Indirectly related source material supporting allocations, journal entries, and similar operator-generated amounts should not be used as a reason to not provide support. The auditor will maintain confidentiality of the support.

If imaged records are provided by the operator, the operator and lead auditors should communicate the needs and availability of monitors, printers, or partitioned drives to assure access commensurate with the size of the audit staff. If the monitors, printers, or partitioned drives provided produce copies that are illegible or of inadequate quality for the auditor to perform a review, the operator should make every effort to provide adequate copies from another source or render other support to substantiate the transaction.

While non-operators are entitled to a complete and thorough review, both auditors and operators should at all times exercise reasonableness, cooperation, and courtesy. Auditors are expected to take exception with joint account transactions that, in their opinion, are not supported by adequate documentation. When support for charges made to the joint account is missing and the operator has been unable to locate or otherwise produce adequate support within the time period for audit resolution as provided by COPAS AG-19, *Expenditure Audit Protocols,* the operator is expected to issue a credit to the joint account to resolve the audit exception. However, the operator's inability to adequately document or support a credit made to the joint account within the time period for audit resolution as provided by COPAS AG-19 is not a sufficient reason to charge the joint account to resolve the exception.

For additional guidelines related to adequate documentation, refer to COPAS MFI-41, *Electronic Invoice Documentation Requirements,* COPAS MFI-42, *Procurement Card and Convenience Check Documentation Requirements,* and other MFIs as applicable.

Council of Petroleum Accountants Societies

Turning Energy Into Synergy

Overhead Rate Adjustments

MODEL FORM INTERPRETATION 47

Publication Date - April 2001

Council Approved

PRUTCOM Approved: January 28, 2025

COPAS MODEL FORM INTERPRETATION 47

ISSUED: April 2001

OVERHEAD RATE ADJUSTMENTS

PREFACE

This COPAS Model Form Interpretation ("MFI") has been reviewed by the Petroleum Accountants Societies through representation on the Joint Interest Standing Committee and Audit Standing Committee and approved by the Council of Petroleum Accountants Societies ("COPAS"). It is recommended as a guide in accounting for joint operations. This MFI pertains to the COPAS model form accounting procedures and does not supersede or override the provisions of any other written agreements.

PROBLEM

The COPAS 1962, 1968, 1974, 1976 Offshore, 1984, and 1986 Offshore Model Form Accounting Procedures all have very similar provisions for adjusting the overhead rates. The COPAS 1995 Model Form Accounting Procedure has unique provisions. All COPAS Model Form Accounting Procedures from the 1962 through 1986 Model Forms state:

> The well rates shall be adjusted as of the first day of April each year following the effective date of the agreement to which this Accounting Procedure is attached. The adjustment shall be computed by multiplying the rate currently in use by the percentage increase or decrease in the average weekly earnings...
>
> The adjusted rates shall be the rates currently in use, plus or minus the computed adjustment.

The COPAS 1998 Project Team Model Form Accounting Procedure states:

> The well rates shall be adjusted on the first day of the production month of April each year following the effective date of the Agreement to which this Accounting Procedure is attached or the effective date of any overhead rate amendment. The adjusted rates shall be the rates on the effective date of the overhead rate, increased or decreased by the COPAS percentage wage index adjustment for each year from such effective date to the date of the adjustment.

The presumption is that the adjustment is computed correctly each year such that applying the cumulative adjustment factors will yield the same result as the sum of the annual adjustments. The intent of the accounting procedure requires clarification to address scenarios when errors in the annual adjustment are not determined for several years. In some cases, the error is not identified until there is a change in operators. In other cases, an operator may have unilaterally decided to forego an adjustment or make an adjustment that was not based on the index stipulated in the governing accounting procedure.

Confusion has also existed in the industry concerning the escalation of rates on April first of the calendar year of the effective date of the agreement.

INTERPRETATION

COPAS believes the COPAS 1998 Project Team Model Form Accounting Procedure clarifies the intent of the previous model forms and reflects industry practice for overhead adjustments. The intent of the agreement, as evidenced by reading the paragraph in its entirety, is for the adjustment to be based on the cumulative change in the index from the effective date of the agreement (or amendment). It is not the intent to perpetuate an error or omission by escalating a rate that has not been adjusted in accordance with the agreement. However, in the case of mutual agreement of the operator and non-operators to adjust the rates in another manner, or to limit the cumulative adjustment, the terms of such agreement will govern. A new operator should confirm the agreement has not been modified if the cumulative adjustment of the base rate varies from the recent rate billed by the prior operator.

Unless the contract specifically provides otherwise, the rate should be escalated every April following the effective date of the agreement, even if the effective date of the agreement is within the first quarter of the calendar year.

The example below illustrates the correct adjustment procedure.

The contract is effective March 1, 1995, with a base rate of $100.00 per month.				
Date	COPAS Factor	Rate Billed	Comment	Correct Rate
3/95		$100.00		$100.00
4/95	+4.4%	104.40	Operator correctly escalated on the first April following the effective date	104.40
4/96	+4.1%	108.68		108.68
4/97	+2.0%	108.90	Operator erroneously escalated 0.2% instead of 2.0%	110.85
4/98	+10.3%	121.22	Operator escalated the previous incorrect rate	122.27
4/99	+5.8%	128.25	Operator escalated the previous incorrect rate	129.36
4/00	-0.5%	127.61	Operator de-escalated the previous incorrect rate	128.71

If the operator discovered the error in 2000, it could correct the bills for 1998 and 1999 but could not correct 1997 because of the contractual 24-month limitation on adjustments. Nonetheless, it would be entitled to bill $128.71 in April 2000. In the above example, if a new operator took over in January 2000, the new operator should bill $129.36 in January 2000 and adjust the rate to $128.71 in April 2000.

Application and Calculation of Drilling Overhead

MODEL FORM INTERPRETATION 48

Publication/Revision Date - April 2012

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COPAS MODEL FORM INTERPRETATION 48

APPLICATION AND CALCULATION OF DRILLING OVERHEAD

TABLE OF CONTENTS

I. INTRODUCTION

The objective of this document is to provide guidance to the industry in determining which type of overhead rate, drilling/development rate or producing/operating rate, applies under various scenarios. It also provides guidance in calculating overhead charges once the appropriate overhead rate is established.

The drilling overhead charge represents the charge to the joint account that allows the operator to recover some of its indirect costs. The method used to calculate this charge is either based on a percentage of costs or the number of qualifying days. These two methods result in a simplified means of recovering such indirect costs versus having to determine what actual costs are. This document helps to explain how to calculate the number of qualifying days for charging drilling overhead on drilling, completion, workover, and recompletion operations, as well as how to assess percentage overhead.

The information in this document is intended to aid in implementing the terms of the COPAS model form accounting procedures. However, the operating agreement, accounting procedure, and other relevant agreements governing a particular property will always take precedence and should be taken into consideration.

II. COMBINED FIXED RATE OVERHEAD

The drilling overhead provisions in the various COPAS model form accounting procedures differ from one another, particularly with respect to the combined fixed rate overhead provisions. These differences are sometimes significant and obvious, but more often they are subtle. Regardless, these differences create difficulty in interpreting, and hence, calculating overhead charges. The following table provides a high-level synopsis of the drilling overhead provisions. The actual drilling overhead provisions from the COPAS model form accounting procedures can be found in Exhibit 1.

Combined Fixed Rate Drilling Overhead

Model Form	Application	Start	Stop
COPAS 1962	Drilling	Spud date	Date drilling or completion rig released, whichever is later*
	Plugging back Deepening Converting to source or input well Workover requiring drilling or workover rig	Same as drilling wells	Same as drilling wells
COPAS 1968	Drilling	Spud date	Date drilling or completion rig released, whichever is later*
	Plugging back Deepening Converting to source or input well Workover requiring drilling rig or workover rig capable of drilling	Same as drilling wells	Same as drilling wells
COPAS 1974	Onshore drilling	Spud date	Date drilling or completion rig released, whichever is later*
	Offshore drilling	Date drilling or completion equipment arrives on location	Date drilling or completion equipment moves off location or rig released, whichever is first*
	Workovers, recompletions lasting five or more consecutive days	Date workover operations, with rig, commence	Date rig released*

Model Form	Application	Start	Stop
COPAS 1976 Offshore	Drilling	Date drilling or completion equipment arrives on location	Date drilling or completion equipment moves off location or rig released, whichever is first*
	Workovers, recompletions lasting five or more consecutive days	Date workover operations with rig or wireline unit commence	Date rig or wireline unit released*
COPAS 1984	Drilling	Spud date	Date drilling rig, completion rig or other unit used in completion is released, whichever is later*
	Workovers, recompletions lasting five or more consecutive work days	Date workover operations, with rig or other units used in workover, commence	Date rig or other unit released*
COPAS 1986 Offshore	Drilling	Date drilling or completion equipment arrives on location	Date drilling or completion equipment moves off location or rig released, whichever is first*
	Workovers or recompletions lasting five or more consecutive work days	Date workover operations, with rig or other units used in workover, commence	Date rig or other unit released*
COPAS 1995	Onshore drilling	Spud date	Date drilling or completion equipment released, whichever later*
	Offshore drilling	Date drilling or completion equipment arrives on location	Date drilling or completion equipment moves off location or rig released, whichever is first*
	Workover, recompletion, abandonment lasting five or more consecutive work days	Date workover operations, with rig or other units used in workover, commence	Date rig or other unit released*
COPAS 1998 Project Team	Onshore drilling	Spud date	Date drilling or completion equipment released, whichever is later*

Model Form	Application	Start	Stop
	Offshore drilling	Date drilling or completion equipment arrives on location	Date drilling or completion equipment moves off location or rig released, whichever is first*
	Workover, recompletion, abandonment lasting five or more consecutive work days	Date workover operations, with rig or other units used in workover, commence	Date rig or other unit released*
COPAS 2005	Onshore drilling	Spud date	Date drilling or completion equipment released, whichever is later*
	Offshore & inland waters drilling	Date drilling or completion equipment arrives on location	Date drilling or completion equipment moves off location or is released, whichever is first*
	Workover, recompletion, abandonment lasting five or more consecutive work days	Date operations, with rig or other units used in operations, commence	Date rig or other unit released*

* Except no charges during suspension of operations for 15 or more consecutive days.

The following discussion dissects the various provisions of the accounting procedures and isolates specific issues. Examples are included in each discussion topic. Sections IV and V provide additional examples incorporating a combination of the concepts presented below.

A. Commencement and Termination of Drilling Overhead – Drilling Wells

The COPAS 1962, 1968, 1984 Model Form Accounting Procedures and the onshore drilling provisions of the 1974, 1995, 1998 Project Team, and 2005 COPAS Model Form Accounting Procedures state that drilling overhead will commence on the "spud date." Spud date, for the specific purpose of calculating onshore drilling overhead under the COPAS model form accounting procedures, is defined as the day of first penetration of the ground by a rig or other unit for the purpose of drilling a proposed well. While spudding includes the conductor hole, it does not include drilling of the rathole/mousehole for the proposed well. The rathole and mousehole do not attract overhead because they are not the wellbore itself, but rather used in operations to drill the wellbore. The rathole is used for placement of the kelly during hoisting operations and the mousehole is used to hold in place the next joint of drill pipe to be used during drilling operations. The rig or other unit used must be capable of drilling the entire conductor hole and it is the operator's responsibility to provide substantive support for the day of first penetration.

The above definition is consistent with the vast majority of industry sources, including the following:

British Columbia Ministry of Finance
Bureau of Safety and Environmental Enforcement (formerly BOEMRE and MMS)
Colorado Energy and Carbon Management Commission
Energy Information Administration, U.S. Govt.
Kansas Corporation Commission
Louisiana Department of Energy and Natural Resources
New Mexico Energy, Minerals and Natural Resources Department
Schlumberger Oilfield Glossary
Society of Petroleum Engineers
State of Utah, Division of Administrative Rules
Texas Railroad Commission
U.S. Department of the Interior
Wyoming Oil and Gas Commission

The COPAS 1974 (its offshore provisions), 1976 Offshore, 1986 Offshore, 1995, 1998 Project Team, and 2005 COPAS Model Form Accounting Procedures state that drilling overhead starts when drilling equipment arrives on location. A question arises as to which date to use when the equipment arrives in pieces, over the course of two or more days.

One interpretation is that drilling overhead begins the first day the drilling equipment begins to arrive on location, regardless of whether it is ready for operations. Under another interpretation, the drilling overhead begins when all of the drilling equipment has arrived onsite. Time spent assembling the rig is included in the number of days for which drilling overhead can be billed under either of these interpretations.

A third interpretation is that the drilling overhead does not start until all the equipment has arrived on location, been assembled, and is capable of drilling. Under this approach, the time spent assembling the rig is not included in the number of days for which drilling overhead can be billed.

The language in the accounting procedures does not specifically address which approach to take in this situation. One factor to consider in resolving this issue is that the operator normally incurs additional overhead costs prior to commencement of drilling operations and prior to the actual arrival of equipment on location. Therefore, the recommended method for determining how many days are subject to drilling overhead is to start with the date the first equipment actually arrives on location and includes staging and rig assembly time in the number of days for which drilling overhead should be billed.

As an example, assume the following:

- First barge with components of platform drilling rig arrived 1/1;
- Last barge with components of platform drilling rig arrived 1/6;
- Rig assembly completed 1/20;
- Drive pipe run 1/21 (conductor pipe set by driving it into soft soil);
- Rig inserts bit into drive pipe and continues drilling on 1/25;
- Equipment moved off location and rig released 2/10.

In this example, for the COPAS 1974, 1976 Offshore, 1986 Offshore, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures, for offshore provisions, the number of days that should be billed for drilling overhead would be 41, calculated from the date of first arrival, 1/1, through the date the rig was released, 2/10, consisting of 31 days for January and 10 days for February.

Note: For the COPAS 1962, 1968, onshore drilling provisions of the 1974, 1984, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures, drilling overhead commences when the ground is penetrated. Thus, there would be 21 drilling overhead days, calculated from the spud date (conductor run), 1/21, through the date the equipment was released, 2/10, consisting of 11 days in January and ten days for February.

In the COPAS 1962, 1968, 1974 (onshore provision), 1984, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures, the drilling overhead terminates "on the date… rig is released." In the COPAS 1974 (offshore provision), 1976 Offshore, 1986 Offshore, and 2005 Model Form Accounting Procedures, the drilling overhead terminates "on the date… equipment moves off location or rig is released, whichever occurs first…." The rig release date is generally well known and noted on drilling reports and invoices for day rate type drilling contracts. "Equipment moves off location" raises the same arguments as the commencement issues discussed above, (i.e., the equipment leaves in stages, so does overhead terminate when the first shipment or the last shipment takes place?) In order to be consistent with the "moves on location" logic, the recommended method is to terminate drilling overhead on the date the last equipment leaves the location. It is important to remember that under the COPAS 1974, 1976 Offshore, 1986 Offshore, and 2005 Model Form Accounting Procedures, either one of two events, rig release or rig moving off location, can cause drilling overhead to cease. Therefore, the "moves off location" trigger will apply only if that event occurs prior to rig release.

B. Workovers and Recompletions Qualifying for Drilling Overhead

The COPAS 1962 and 1968 Model Form Accounting Procedures provide that drilling overhead can be charged for wells that are being plugged back, deepened, or converted to a source or input well. There are no qualifications, in terms of number of days or equipment type, for these operations to receive drilling overhead. Regarding workover operations, these same accounting procedures stipulate that only workover operations requiring the use of a drilling or workover rig qualify for drilling overhead.

The COPAS 1974 and 1976 Offshore Model Form Accounting Procedures changed the specific requirements found in the COPAS 1962 and 1968 Model Form Accounting Procedures in that a workover must use a drilling rig or workover rig (more specifically, a workover rig capable of drilling, in the 1968 Model Form Accounting Procedure) to qualify for drilling overhead. The reason for the change was because that requirement was difficult to audit and because technological advances made workovers feasible without using this specific equipment. These later COPAS model form accounting procedures state that any workover or recompletion operation, with rig, lasting five or more consecutive days, qualifies for drilling overhead.

The COPAS 1984, 1986 Offshore, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures require workovers and recompletions last at least five consecutive work days to qualify for drilling overhead. The 1995, 1998 Project Team and 2005 Model Form Accounting Procedures also include abandonment operations as an activity qualifying for drilling overhead, provided the five consecutive work days criterion was met.

The differences in the later accounting procedures are subtle: "consecutive days" versus "consecutive work days." This may lead to inadvertent errors if the person responsible for inputting drilling days or otherwise responsible for the drilling overhead calculation is not trained in the differences among the accounting procedures and/or is not aware which form governs the property in question.

However, even when given the contract provisions, it can be difficult to calculate the number of days subject to drilling overhead. There may be confusion about whether to count weekends and holidays in determining whether the consecutive days criterion was met when operating under a 1974 or 1976 Offshore Model Form Accounting Procedure. For operations subject to the COPAS 1984, 1986 Offshore, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures, a question that arises is whether drilling overhead applies during a weekend suspension of operations.

Since the COPAS 1974 and 1976 Offshore Model Form Accounting Procedures require consecutive days, the literal meaning of the contract is that weekends and holidays should be considered in determining whether the five consecutive days requirement was met.

To illustrate this concept, consider the following example:

- Workover operations commenced Thursday, 3/4;
- Workover operations stopped Friday, 3/5;
- Workover operations resumed Monday, 3/8;
- Workover operations completed and rig released Wednesday, 3/10.

In this example, a property subject to a COPAS 1974 or 1976 Offshore Model Form Accounting Procedure would not receive drilling overhead for this workover operation. Even though the workover lasted five days, they were not consecutive calendar days. On the other hand, had this same operation been commenced on Monday and completed on Friday, it would have received drilling overhead since the five days would have been consecutive.

If the property were subject to a COPAS 1984, 1986 Offshore, 1995, 1998 Project Team, or 2005 Model Form Accounting Procedure, it would qualify for drilling overhead since the workover operation lasted for a period of five consecutive workdays. The weekend work stoppage would not be relevant.

Next, consider the following example:

- Workover operations commenced Thursday, 3/4;
- Workover operations stopped Friday, 3/5;
- Workover operations resumed Monday, 3/8;
- Workover operations completed and rig released Friday, 3/12.

In this example, the workover operation met both the five consecutive days and five consecutive work days requirements for the COPAS 1974 Model Form Accounting Procedure and all later COPAS model form accounting procedures. In this case, the only suspension of operations was two days, far short of the 15-day suspension limit (see Section II.C). The workover operation would qualify from the time the operation commenced, 3/4, until it ceased on 3/12, or nine days.

Lastly, consider the following example:

- Workover operations with rig commenced Monday, 3/1;
- No activity 3/3 through 3/10;
- Workover operations resume Thursday, 3/11;
- No activity Saturday, 3/13 and Sunday, 3/14;
- Workover operations resumed Monday, 3/15;
- Workover operations completed and rig released Friday, 3/19.

In this example, the workover operation met both the five consecutive days and five consecutive work days requirements for the COPAS 1974 Model Form Accounting Procedure and all later COPAS model form accounting procedures. The five-day test is intended to only determine if an operation can be charged drilling overhead; it is not intended to define the beginning date. Drilling overhead for workovers begins when the operation commences. Refer to Section II.E for information on commencement. Therefore, the entire workover operation would qualify for drilling overhead from commencement, 3/1, until it ceased on 3/19, or 19 days. Occasionally, the workover operation encounters difficulty such as stuck tools, casing holes, or other downhole troubles and the operator has to change the procedure. It is not always clear whether the next steps are a continuation of the same workover or an entirely new procedure, and the significance of that is for authorization purposes. That is a land and legal issue that is beyond the scope of this document.

C. Suspension of Operations

All COPAS model form accounting procedures contain a clause stipulating that drilling overhead is not charged during suspension of operations for 15 or more consecutive days (or "consecutive calendar days" for the COPAS 1984 and later COPAS model form accounting procedures). The COPAS 1974 Model Form Accounting Procedure and later COPAS model form accounting procedures also state that no drilling overhead will be charged for suspension of workover and recompletion operations lasting 15 or more consecutive days. However, the COPAS 1962 and 1968 Model Form Accounting Procedures do not explicitly state drilling overhead stops when workover or recompletion operations are suspended for 15 or more consecutive days. Instead, the COPAS 1962 and 1968 Model Form Accounting Procedures state that wells being plugged back, deepened, converted to a source well, or which are undergoing a workover requiring use of a drilling or workover rig shall be considered the same as drilling wells. Therefore, the provisions regarding the cessation of drilling overhead charges when operations are suspended 15 or more consecutive days applies to workover and recompletion operations.

There sometimes are differing interpretations as to the activities that constitute "operations." For example, with multi-staged frac techniques, there are often days or weeks of downhole inactivity while other work is performed on the surface, such as assembling frac equipment, filling frac tanks, or digging and filling a frac pit. A question has risen if this fracing preparatory work qualifies as "operations," or counts as a suspension of operations. The COPAS model form accounting procedures refer to a suspension of operations but do not qualify that by limiting it to a suspension of downhole activities. For ease of administration and consistence in applying drilling overhead, COPAS recommends that as long as the well is sustaining some type of drilling, completion, workover, or recompletion activity, and as long as there is no suspension of such work for 15 or more consecutive days, drilling overhead is chargeable. These provisions are not intended to include time spent production testing, cleanup operations, etc. These are considered production activities.

Another question that arises from time to time is whether to charge drilling overhead for suspension of operations over the weekend or holidays. The COPAS model form accounting procedures do not place any qualifications on the reason operations were suspended. Therefore, if the workover or recompletion ceases for weekends or holidays, drilling overhead may still be chargeable as long as the period of cessation did not exceed 14 consecutive days.

If the operations cease, one need simply count the number of consecutive days of suspended operations without considering whether the rig or crew normally works on weekends or holidays. Weekends and holidays are counted in determining whether there were 15 or more days, even though they may not be work days.

Yet another issue that may arise is the situation where the operator conducts multiple operations in tandem, with suspensions on a well while working on another well. For example, suppose the operator is conducting a two-well development drilling program on a platform for a total of 40 days, working as follows:

Operation	Days	
Drill Well # 1	10	1/1 through 1/10
Drill Well # 2	10	1/11 through 1/20
Complete Well # 1	10	1/21 through 1/30
Complete Well # 2	10	1/31 through 2/9
Total Days	40	

There may be various operational reasons why the operator would conduct the operations in this manner. Regardless of the reasons for the suspension between drilling and completion operations on each well, the suspension on either well did not exceed 14 days. Consequently, each well qualifies for drilling overhead from the date the rig arrived on location (on the joint property for Well # 1 and on the well slot for Well # 2). Drilling overhead ceases when the rig or completion equipment moved off location (off the well slot for Well # 1 and off the joint property for Well # 2). Therefore, Well # 1 attracts 30 days (1/1 through 1/30) and Well # 2 attracts 30 days (1/11 through 2/9).

In Section III.C.(Consecutive Remedial Operations) the above concept is reinforced. The drilling overhead applies to each individual well and does not apply to consecutive operations. In the above example, each individual well is evaluated for drilling overhead, not the combination of wells. Refer to Section III.C. (Consecutive Remedial Operations) for a more detailed discussion.

D. Force Majeure Events

All COPAS model form accounting procedures state drilling overhead ceases when drilling, completion, or workover operations are suspended for 15 or more consecutive days. The actual wording of these provisions differs slightly; however, the result is the same. Also, as explained in Section II.B. (Workovers and Recompletions Qualifying for Drilling Overhead), there is a five consecutive work day requirement related to workover operations for most accounting procedures.

The question is whether there are any occurrences that would cause interruptions of drilling or completion operations which would not count in determining whether the 15-day suspension clause applied. In the case of workover or recompletion operations, a similar question is whether there are any interruptions or unusual circumstances that would not be counted in determining whether the operation meets the five consecutive days criterion to qualify for drilling overhead.

Questions arise as to whether a force majeure event creates an exception to the 15-day criterion. The force majeure provision is used to excuse a party from performing obligations and does not apply to overhead assessment. Therefore, the 15-day criterion is absolute and there are no exceptions, even for force majeure events. It is also important to note that some force majeure events may qualify for catastrophe overhead, leaving the operator with another means of recovering its overhead costs during force majeure events.

Force majeure may provide some relief in determining whether the five-day criterion was met. If the force majeure event prevented the operations from being conducted, the force majeure days are not "work days." Therefore, the accounting procedures that contain the "consecutive *work days*" clause may claim force majeure as "non-work days" when calculating qualification against the five consecutive *work day* rule. Additionally, if the total suspension, including force majeure days, lasted fewer than 15 days, those suspended days may be charged at the drilling overhead rate. If the total suspension of operations, including force majeure events, lasts 15 or more days, those suspended days may not be counted for the drilling overhead rate.

As an example, assume the following:

- COPAS 1986 Offshore Model Form Accounting Procedure;
- Workover operations commenced 3/6;
- Workover operations suspended due to hurricane 3/9;
- Workover operations resumed 3/29;
- Workover operations completed 3/31.

Drilling overhead should be charged for seven days (from 3/6 through 3/9, which is four days, and from 3/29 through 3/31 which is three days). The period between March 9 and March 29 were not considered normal working days due to the force majeure event. Consequently, the operation met the five consecutive work days rule. However, the suspension of operations exceeded 14 days and those days may not be counted for drilling overhead.

E. Commencement of Drilling Overhead - Workover Operations

The provisions in the COPAS 1962 and 1968 Model Form Accounting Procedures concerning overhead on workover or recompletion operations state that wells being plugged back, drilled deeper, converted to a source or input well, or which are undergoing any type of workover shall be considered the same as a drilling well. The provisions for the drilling wells apply and those provisions state that the drilling overhead shall begin on the date the well is spudded. This has been interpreted as meaning drilling overhead for workover or recompletion operations starts when the well is entered.

The COPAS 1974, 1976 Offshore, 1984, 1986 Offshore, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures all state that drilling overhead for workover operations starts when workover operations commence. There are differing interpretations as to when workover operations commence. Is it when site preparation, rigging up, or other physical operations onsite commence or when the workover rig or other equipment used in the operation enters the wellbore?

For ease of administration and consistency in applying drilling overhead (and not for lease maintenance purposes), COPAS recommends that when using the COPAS 1974 Model Form Accounting Procedures and later COPAS model form accounting procedures, workover operations are deemed to have commenced, and hence drilling overhead starts, when the well is entered.

Assumptions

- COPAS 1984 Model Form Accounting Procedure;
- Workover rig arrived on location 9/1;
- Rigged up through 9/6;
- Well entered 9/7;
- Work completed and rig released 9/30.

Solution (commence issue)
Drilling overhead for workover operations begins when the "operation is commenced" under the 1984 Model Form Accounting Procedure. Therefore, charge 24 days, from 9/7 when the well was entered, through 9/30, the date the rig was released.

F. Equipment Type Qualifying for Drilling Overhead

When the COPAS 1962 and 1968 Model Form Accounting Procedures were written, the completion work had to operationally be done using the same rig used in drilling or a smaller completion rig. In the mid-1970s, the equipment evolved so that other units could be used to complete the well. These units were smaller and did not command the high day rates associated with the larger, more traditional drilling or completion rigs. This technology saved drilling costs for both the operator and non-operator.

Technological advances will certainly continue, and rigs of the future may look very different from today. As the technology advances, operators and non-operators need to understand the intent behind the overhead rates. The intent of overhead was to compensate the operator for the additional overhead costs associated with drilling a well or conducting certain other operations such as recompleting or working over the well. These overhead costs are not necessarily reduced for the operator just because a technological advance changed the physical characteristics of the rig or other aspects of the operation. Notwithstanding the above, the following is recommended for today's environment.

The COPAS 1962 Model Form Accounting Procedure requires the use of a drilling or workover rig for workovers to be eligible for drilling overhead. This rig requirement does not apply to recompletions or well conversions, so any rig that is capable of conducting these operations inherently meets that criterion.

The COPAS 1968 Model Form Accounting Procedure requires the use of a drilling rig or completion rig. Workovers require a rig that is capable of drilling. As with the 1962 Model Form Accounting Procedure, the rig requirement does not apply to recompletions or well conversions. COPAS MFI-2, *COPAS 1968 Model Form Accounting Procedure Interpretation,* establishes some criteria to consider in determining whether a rig is capable of drilling. MFI-2 states:

> "… It is recognized that the definition of what constitutes a workover rig "capable of drilling" will vary between companies; however it is generally defined as being:
>
> (a) the size rig necessary to drill to the formation being reworked, or
>
> (b) in the event work is being conducted up the hole from the formation served by the equipment being serviced, the size of rig necessary to drill to the formation served by such equipment, or
> (c) in the event work is being conducted which has no relation to a particular formation, the size rig which would be required to drill to the deepest producing horizon.
>
> Engineering practices considered generally accepted in the area of operations by the industry should be used in the determination of a rig capable of drilling under the above standards."

Therefore, the workover rig must comply with those general definitions to qualify for drilling overhead. If the unit used is not capable of drilling, then drilling overhead cannot be charged under these particular forms, absent other agreement among the parties.

The COPAS 1974 Model Form Accounting Procedure provides that any type of workover or recompletion lasting five or more consecutive days qualifies for drilling overhead. The drilling overhead is applied from the date the operation, with rig, commences, through the date of rig release. A rig is a machine for hoisting pipe, wireline, or tools into and out of a well.

The COPAS 1976 Offshore Model Form Accounting Procedure states that drilling overhead charges for workovers or recompletions (again, assuming the five-day criterion was met) starts when workover operations, with rig or wireline unit, commence through the date of rig or wireline release. A rig has already been defined above. A wireline unit contains a string of tools, wireline, and a power system to let out and retrieve the line. The unit includes instruments to indicate weight, line speed, and depth of the tool string. Therefore, in order for drilling overhead to be charged, the equipment used must meet these definitions.

The COPAS 1984, 1986 Offshore, 1995, 1998 Project Team, and 2005 Model Form Accounting Procedures state that drilling overhead charges for workovers meeting the other requirements, start when a rig or other unit used in the workover commence through date of rig or other unit release. COPAS MFI-17, *COPAS 1984 Model Form Accounting Procedure Interpretation,* and COPAS MFI-19, *COPAS 1986 Offshore Model Form Accounting Procedure Interpretation*, state that "Technology has produced tools that are able to perform such operations without requiring the use of large drilling rigs or other high cost units, and therefore, it has become more complicated to determine when these operations should qualify for drilling well overhead rates. Rather than require an accountant to know what type of equipment is capable of drilling or use some other technical method, if the operation requires five or more consecutive work days using a rig or other unit, the operations qualify for the drilling well rate." Therefore, regardless of the type of rig or unit used in the operation, drilling overhead can be charged, assuming all other requirements are met. Refer to examples 2 and 3 in Section V (Examples – Drilling Overhead Calculations).

III. PERCENTAGE BASED OVERHEAD

The percentage based overhead provisions in the various COPAS model form accounting procedures do not vary as much as the combined fixed rate overhead provisions. The differences tend to be subtle and for the most part have little effect on calculation of the overhead rates. The following table provides a recap of the provisions, highlighting the more significant variances. The actual percentage based overhead provisions from the COPAS model form accounting procedures can be found in Exhibit 2 of this document.

PERCENTAGE BASED OVERHEAD

Model Form	Overhead Type	Application	Exclusions
COPAS 1962	Not applicable		
COPAS 1968 COPAS 1974 COPAS 1976 Offshore	Development	Drilling, redrilling, deepening, or remedial operations on any or all wells involving use of drilling crew and equipment; preliminary drilling preparation costs; abandoning wells not completed as producers; construction, installation, expansion or other fixed asset work, except major construction	Legal costs, salvage credits
	Operating	All other costs not subject to development or major construction/catastrophe overhead	Rentals and royalties; legal costs, salvage credits; value of injected substances purchased for secondary recovery; taxes and assessments on mineral interest in joint property
COPAS 1984	Development	Drilling, redrilling, deepening, or remedial operations on wells involving use of drilling crew and equipment capable of drilling to the producing interval on the joint property; preliminary drilling preparation costs; abandoning wells not completed as producers; construction, installation, expansion of fixed assets except if major construction	Same as 1968 - 1976

Model Form	Overhead Type	Application	Exclusions
	Operating	Same as 1968 - 1976	Same as 1968 - 1976
COPAS 1986 Offshore	Development	Drilling, redrilling, deepening of any or all wells; remedial operations requiring five or more consecutive work days on any or all wells; preliminary drilling preparation costs; abandoning of wells not completed as producers; construction, installation, expansion of fixed assets except if major construction	Same as 1968 - 1976
	Operating	Same as 1968 – 1976	Same as 1968 - 1976
COPAS 1995	Development	Drilling, redrilling, plugging back, deepening; workover operations requiring five or more consecutive work days on any or all wells; preliminary drilling preparation costs; abandonment of wells not completed as producers; construction, installation, expansion of fixed assets except if major construction	Same as 1968 - 1976
	Operating	Same as 1968 - 1976	Same as 1968 - 1976
1998 Project Team	Development	Drilling, redrilling, plugging back, sidetracking, deepening; workover operations requiring 15 or more consecutive work days on a well; preliminary drilling preparation costs; abandonment of wells not completed as producers; construction, installation, expansion of fixed assets except if major construction	Legal costs; salvage credits; project team expenses & overhead

Model Form	Overhead Type	Application	Exclusions
	Operating	All other costs except those subject to project team overhead, major construction/catastrophe overhead	Rentals and royalties; legal costs, salvage credits; value of injected substances purchased for enhanced recovery; property, ad valorem and other taxes and assessments on mineral interest in joint property
COPAS 2005	Development	Drilling, redrilling, sidetrack, deepening; plugback or workover operations requiring five or more consecutive work days on a well; preliminary drilling preparation costs; abandonment of wells not completed as producers; construction, installation, expansion of fixed assets except if major construction or catastrophe	Same as 1968 – 1976
	Operating	Same as 1968 - 1976	Rentals and royalties; legal costs, salvage credits; value of substances purchased for enhanced recovery; property, ad valorem & other taxes and assessments on mineral interest in joint property

A. Overhead on Plugging Back and Sidetracking Operations

The development overhead rate always applies to drilling, redrilling and deepening operations, regardless of which accounting procedure governs the property. There are no minimum time requirements, such as the operations lasting at least five consecutive days, nor does the agreement place restrictions on the type of equipment used in these operations. However, for COPAS model form accounting procedures prior to the COPAS 1995 Model Form Accounting Procedure, it is not always clear which rate applies to plugging back or sidetracking operations.

If the form does not address plugging back operations and there is no other agreement between the parties, COPAS recommends plugging back and sidetracking operations be treated the same as remedial operations. Thus, for the older COPAS model form accounting procedures, if the plugging back or sidetracking operation involves the use of a drilling crew or equipment, the development rate applies. Under the 1986 Offshore Model Form Accounting Procedure, the development rate applies if the plugging back or sidetracking operation lasts five or more consecutive work days. The rationale is that work using a drilling crew and equipment, or which lasts at least five days, has a larger expenditure base to which the development rate applies, thus providing the operator with recovery of increased overhead costs associated with more significant, non-routine, operations.

B. Overhead on Workover/Remedial Operations

COPAS model form accounting procedures do not define remedial or workover operations (also sometimes referred to as "reworking"). Likewise, most operating agreements do not define these terms. The AAPL Model Form 610-1989 Operating Agreement for onshore operations defines "rework" as "an operation conducted in the wellbore to secure, restore, or improve production in a zone which is currently open to production, but excludes routine repair or maintenance work." The AAPL Model Form 710, Offshore Operating Agreement (1996), defines "rework" as "an operation conducted in a well to restore, maintain, or improve production, excluding drilling, sidetracking, deepening, completing or recompleting the well." The AAPL Model Form 810, Offshore Deepwater Operating Agreement, defines "workover" as "an operation conducted in an existing well to restore, maintain or improve production."

Under the COPAS 1986 Offshore Model Form Accounting Procedure and later COPAS model form accounting procedures, development overhead applies to workover operations lasting five or more days (15 days under the COPAS 1998 Project Team Model Form Accounting Procedure). In other words, the operation must meet two criteria. It must qualify as a workover operation, as described above, and it must meet the threshold number of days.

The COPAS 1968, 1974, 1976 Offshore, and 1984 Model Form Accounting Procedures require remedial operations to involve the use of drilling crew and equipment. COPAS MFI-2, *COPAS 1968 Model Form Accounting Procedure Interpretation,* states:

> "It is recognized that the definition of what constitutes a workover rig "capable of drilling" will vary between companies; however, it is generally defined as:
>
> (a) the size rig necessary to drill to the formation being reworked, or
> (b) in the event work is being conducted up hole from the formation served by the equipment being serviced, the size of rig necessary to drill to the formation served by such equipment, or
> (c) in the event work is being conducted which has no relation to a particular formation, the size rig which would be required to drill to the deepest producing horizon.

> Engineering practices considered generally accepted in the area of operations by the industry should be used in the determination of a rig capable of drilling under the above standards."

The above definition is not explicitly stated in subsequent MFIs. However, it is logical to apply this definition to those COPAS model form accounting procedures using the "capable of drilling" language since the later MFIs do not alter nor do they expound upon this language. Therefore, the above criteria may be utilized to determine whether remedial operations qualify for development percentage overhead under the COPAS 1968, 1974, 1976 Offshore, and 1984 Model Form Accounting Procedures.

C. Consecutive Remedial Operations

The COPAS 1986 Offshore and 1995 Model Form Accounting Procedures provide that remedial operations lasting five or more consecutive work days on "any or all wells" qualify for the development rate; remedial operations lasting fewer than five consecutive work days qualify for the operating rate. There are different interpretations of the meaning of the phrase "any or all wells," particularly where there are back-to-back operations. Some have read this phase to mean that individual wells not qualifying for the development rate because the remedial operation does not cover the required minimum number of days should be added together with other wells in the back-to-back operations to determine whether the five-day criterion was met. Another interpretation is that this phrase actually emphasizes that any and all types of wells qualify for the development rate under a percentage overhead election, as opposed to the various well-type restrictions that are encountered under a combined fixed rate overhead approach. COPAS recommends applying the five consecutive work day language to individual wells, not a combination of wells. This is true even if there are back-to-back remedial operations on the same joint property where the cumulative number of days equals or exceeds five consecutive work days, when fewer than five consecutive work days are spent on an individual well.

The COPAS 1998 Project Team Model Form Accounting Procedure states that the development rate applies to workover operations requiring a period of 15 consecutive work days or more on a well. In this form, the intent is to apply the 15-workday criterion on a well-by-well basis.

Under the COPAS 1968, 1974, and 1976 Offshore Model Form Accounting Procedures, the development rate applies to operations using drilling crew and equipment. Under the 1984 COPAS Model Form Accounting Procedure, the development rate applies to operations using a drilling rig and crew capable of drilling to the producing interval. The amount of time spent on one well or multiple wells is irrelevant in calculating percentage overhead under these COPAS model form accounting procedures.

IV. EXAMPLES – SPUD DATE DETERMINATION

This Section provides additional examples incorporating the concepts discussed in Section II Combined Fixed Rate Overhead). These examples are valid for all onshore COPAS model form accounting procedures.

Example 1

Assumptions

- Small rig drills water source well on 8/1;
- Small rig drills conductor and rathole/mousehole on 8/8;
- Drilling rig drills out from under conductor on 8/12.

Solution

Spud Date is 8/8 (drilling overhead calculation begins). Drilling overhead begins at first penetration of the ground in the proposed well. The drilling of the water source well does not apply to drilling overhead for the proposed well in question. However, water supply wells and disposal wells separately proposed and drilled under the agreement qualify for their own separate drilling overhead charge since the accounting procedures do not limit drilling overhead to producing wells.

Refer to Section II.A.

Example 2

Assumptions

- Small rig drills conductor and rathole/mousehole on 8/8;
- Small rig starts drilling surface hole on 8/9 and sets casing on 8/11 and rigs down; Drilling rig rigs up and resumes drilling on 8/22.

Solution

Spud Date is 8/8 (drilling overhead calculation begins)

Refer to Section II.A.

Example 3

Assumptions

- Drilling rig drills rathole/mousehole on 8/12;
- Drilling rig drills conductor hole on 8/13.

Solution

Spud Date is 8/13 (drilling overhead calculation begins).

Refer to Section II.A.

V. EXAMPLES – DRILLING OVERHEAD CALCULATIONS

This Section provides additional examples incorporating the concepts discussed in Section II Combined Fixed Rate Overhead).

Example 1

<u>Assumptions</u>

- COPAS 1962 Model Form Accounting Procedure;
- Rig arrived on location 3/1;
- Well spudded 3/5;
- Rig released 3/31.

<u>Solution</u>

Drilling overhead should be billed for 27 days, for the period 3/5 through 3/31.

Refer to Section II.A.

Example 2

<u>Assumptions</u>

- COPAS 1962 Model Form Accounting Procedure;
- Rig arrived location 3/1;
- Well spudded 3/5;
- Rig released 3/30;
- Completion rig arrived on location 4/8 to perforate and stimulate well;
- Completion rig released 4/30;
- Wireline unit arrives on 5/3 for bailout and swabbing;
- Wireline unit released 5/10.

<u>Solution</u>

- Charge 27 days in March. Even though the rig was released 3/30, the completion rig was on location within nine days. Since there were fewer than 15 days related to suspended operations, drilling overhead continues until the completion rig is released.
- Charge 30 days in April. Since there were fewer than 15 days related to suspended operations, drilling overhead is billed from the date the drilling rig is released through the date the completion rig is released.
- Charge zero days in May. This is considered completion equipment, required to bring the well to a productive status. However, the COPAS 1962 Model Form Accounting Procedure states drilling days stop when the completion *rig* is released,

rather than other types of equipment. Therefore, drilling overhead is not chargeable in May. Refer to the next example involving a different accounting procedure.

Refer to Sections II.C. and F.

Example 3

Assumptions

- COPAS 1984 Model Form Accounting Procedure;
- Rig arrived location 3/1;
- Well spudded 3/5;
- Rig released 3/30;
- Completion rig arrived on location 4/8;
- Completion rig released 4/30;
- Stimulation/pumping equipment on location 5/3;
- Stimulation/pumping equipment released 5/10;
- Clean-up and testing operations performed 5/11 through 5/20.

Solution

- Charge 27 days in March. Although the rig was released 3/30, a completion rig was on location within nine days so there were fewer than 15 days related to suspended operations. Drilling overhead continues until the completion equipment is released.
- Charge 30 days in April. Since there were fewer than 15 days related to suspended operations, drilling overhead is billed from the date the drilling rig is released through the date the completion equipment is released.
- Charge ten days in May. This is considered completion equipment, i.e., required to bring the well to a productive status, and therefore drilling overhead is chargeable until the completion equipment is released.
- No charge is made during the clean-up and testing since the equipment used in these operations is not equipment used in completion of the well.

Refer to Sections II.C. and F.

Example 4

Assumptions

- COPAS 1962 Model Form Accounting Procedure;
- Workover rig arrived on location 6/1;
- Rigged up through 6/6;
- Wellhead entered 6/7;

- Workover completed and rig released 6/30.

Solution
Charge 24 days, from 6/7, the date the well was entered, through 6/30, when the workover was completed. Since the COPAS 1962 Model Form Accounting Procedure states charges for drilling wells shall begin on the date the well is spudded, i.e., entered, and any wells undergoing any type of workover that requires the use of a drilling or workover rig shall be considered the same as drilling wells, the date the well is entered is the appropriate start date.

Refer to Section II.A.

Example 5

Assumptions
- COPAS 1962 Model Form Accounting Procedure;
- Workover rig arrived on location 8/2;
- Rigged up 8/3;
- Spotted acid 8/4;
- Workover completed and rig released 8/5.

Solution
Drilling overhead of two days should be billed since the workover operations commenced 8/4 and ended 8/5. The COPAS 1962 Model Form Accounting Procedure merely requires use of a drilling or workover rig and does not require workovers last for a period of at least five consecutive days.

Refer to Section II.A.

Example 6

Assumptions
- COPAS 1984 Model Form Accounting Procedure;
- Workover rig arrived on location 8/2;
- Rigged up 8/3;
- Spotted acid 8/4;
- Workover completed and rig released 8/5.

Solution
No drilling overhead should be billed since the COPAS 1984 Model Form Accounting Procedure requires the workover operation last at least five consecutive work days to be eligible for drilling overhead.

Refer to Section II.B.

Example 7

Assumptions

- COPAS 1984 Model Form Accounting Procedure;
- Workover rig arrived on location 9/1;
- Rigged up through 9/6;
- Well entered 9/7;
- Work completed and rig released 9/30.

Solution (commence issue)

Charge 24 days, from 9/7, when the well was entered, through 9/30, the date the rig was released. Charges for drilling wells begin when the "operation is commenced" under the 1984 Model Form Accounting Procedure. There are some differing interpretations on what constitutes commencement of operations.

Refer to Section II.E.

Example 8

Assumptions

- COPAS 1984 Model Form Accounting Procedure;
- Workover rig arrived on location 9/1;
- Rigged up through 9/6;
- Downhole work conducted 9/7 through 9/10;
- Shut-in due to a force majeure event 9/11 through 9/15;
- Workover resumed 9/16;
- Workover completed and rig released 9/18.

Solution (commence issue, charge for suspended days issue)

Charge 12 days, consisting of four days for the period 9/7 through 9/10, plus the five days operations were suspended due to the force majeure event, plus three days for the period 9/16 through 9/18. Drilling overhead charges for workovers begin the date workover operations commence under the COPAS 1984 Model Form Accounting Procedure. Based on the recommendation in Section II.E., the date the well was entered is used as the start date. The crew was prevented from working during the force majeure event, so these days are not considered "work days." Thus, the workover operation lasted more than five consecutive work days and is eligible for drilling overhead. Finally, operations were not suspended for 15 consecutive days or more, so the drilling overhead charges are applied until the date the rig is released.

Refer to Sections II.C., D., and E.

Example 9

Assumptions
- COPAS 1986 Offshore Model Form Accounting Procedure;
- Workover rig arrived on location 9/1;
- Rigged up through 9/6;
- Downhole work conducted 9/7 through 9/10;
- Shut-in due to a force majeure event 9/11 through 9/15;
- Workover resumed 9/16;
- Workover completed and rig released 9/18.

Solution (commence Issue)
Charge 12 days, consisting of the period from 9/7 to 9/18. Under the COPAS 1986 Offshore Model Form Accounting Procedure, drilling overhead for workover operations starts the date workover operations commence, i.e., well entered. The crew was prevented from working during the force majeure event, so these days are not considered work days. Therefore, the workover operation met the five consecutive work days criterion. Finally, operations were not suspended for 15 consecutive days or more, so the drilling overhead charges are applied until the date the rig is released.

Refer to Sections II.A., C., D., and E.

Example 10

Assumptions
- COPAS 1986 Offshore Model Form Accounting Procedure;
- Coiled tubing unit arrived on location 2/1;
- Rigged up through 2/4;
- Entered well 2/5;
- Acidized 2/6 through 2/8;
- Coiled tubing unit released 2/8.

Solution (commence issue)
Drilling overhead is not charged. Charges for workovers begin when workover operations commence, under the COPAS 1986 Offshore Model Form Accounting Procedure. Based on the recommendation in Section II.E. , the date the well was entered is used as the start date. The unit was released on 2/8, for a total of four consecutive work days. Had this operation lasted at least five consecutive work days, it would have qualified for drilling

overhead since the COPAS 1986 Offshore Model Form Accounting Procedure refers to use of a "rig or other unit."

Refer to Sections II.E. and F.

Example 11

Assumptions

- COPAS 1962 Model Form Accounting Procedure;
- Coiled tubing unit arrived on location 2/1;
- Well entered 2/5;
- Acidized 2/6 through 2/8;
- Coiled tubing unit released 2/8.

Solution

Charge zero days because the COPAS 1962 COPAS Model Form Accounting Procedure limits drilling overhead for workovers to those operations using a drilling or workover rig.

Refer to Section II.F.

Example 12

Assumptions

- COPAS 1986 Offshore Model Form Accounting Procedure;
- Workover rig arrived on location 3/1;
- Rigged up through 3/5;
- Entered well and worked 3/6 through 3/11;
- Operations suspended 3/12 through 3/28 due to a force majeure event;
- Operations resumed 3/29;
- Rig moved off location and released 3/31.

Solution

Charge nine days, consisting of six days for the period from the date the workover operations commenced (3/6) through 3/11, plus three days for the period 3/29 through 3/31. The force majeure event suspended operations for more than 14 days, so those days are not chargeable.

Refer to Sections II.D. and E.

Example 13

Assumptions

- COPAS 1984 Model Form Accounting Procedure;
- Drilling rig arrived on location 4/1;
- Well spudded 4/5;
- Drilling rig moved off location 4/15;
- Completion rig moved on location 4/20;
- Completion operations conducted 4/20 through 4/29;
- Completion equipment, including units used for fracturing and acidizing, released 4/30;
- Unit for production testing and bottomhole pressure tests utilized 5/1 through 5/10;
- Well placed on production 5/11.

Solution

Charge 26 days. Under the COPAS 1984 Model Form Accounting Procedure, charges for drilling wells start on the spud date, in this case 4/5. Fewer than 15 days elapsed during the suspension of operations between the drilling and completion phases, so drilling overhead charges continue during that period. The COPAS 1984 Model Form Accounting Procedure provides that drilling overhead charges cease when the drilling, completion rig or other unit used in completion is released, whichever is first. Testing equipment is not considered completion work since the well was capable of producing once the completion rig was released 4/30. Therefore, completion charges cease when the completion rig is moved off location on 4/30. In this example, although the well does not qualify for drilling overhead in May, it does qualify for producing overhead since it was placed on production 5/11.

Refer to Sections II.A. and C.

Example 14

Assumptions

- COPAS 1984 Model Form Accounting Procedure;
- Rig arrived on location 4/1;
- Entered well and replaced tubing 4/2 through 4/10;
- Ran bottomhole pressure and tracer surveys 4/11 through 4/21;
- Installed downhole pump 4/22 through 4/25;
- Rig released 4/25.

Solution

Charge 24 days. Under the COPAS 1984 Model Form Accounting Procedure, workovers lasting at least five consecutive work days qualify for drilling overhead. Since part of this operation involved tubing replacement and installing a pump to increase production, it can be considered a workover operation. While the bottomhole pressure and tracer surveys would not normally qualify for drilling overhead, the "suspension" for this activity was less than 15 days. Under the COPAS 1984 Model Form Accounting Procedure, drilling overhead on workovers starts when the workover operation commences and continues until the rig or other unit is released. Work is considered to have commenced on 4/2 and continued through 4/25.

This solution assumes the tubing replacement and pump installation were part of the same operation, as evidenced by appearing on the same AFE or project proposal. In that case, there is one operation having a suspension period. However, if the operator initially planned only to replace the tubing and subsequently decided to install a pump, the tubing replacement and pump installation constitute separate workover operations, each of which must independently meet the five-day criterion.

Refer to Section II.E.

Example 15

Assumptions

- COPAS 2005 Model Form Accounting Procedure;
- Well spudded 2/3 (non-leap year);
- Drilling rig released 3/1;
- Completion rig cleaned out and perforated the well 3/20 and 3/21;
- Set up frac tanks and preparatory work 3/22 to 4/9;
- Frac well 4/10 through 4/13;
- Coil tubing unit drilled out frac plugs and cleaned out well 4/21 through 4/23;
- Well testing and flowback crew work 4/24 through 5/1.

Solution

Charge 62 days. Under the COPAS 2005 Model Form Accounting Procedure (and all post-COPAS 1974 onshore model form accounting procedure provisions), drilling overhead qualifies for 2/3 through 3/1, and 3/20 through 4/23. The period between the drilling rig release and the completion rig arrival does not qualify due to the suspension exceeding 14 days. The frac tank setting and preparatory work qualifies for drilling overhead because the well was sustaining some type of completion activity. The 4/24 through 5/1 well testing/flowback period does not qualify for drilling overhead because it is not a chargeable "operation" but instead a production activity.

Refer to Section II.C.

Example 16

Assumptions

- COPAS 2005 Model Form Accounting Procedure;
- Well spudded 3/1;
- Drilling rig released 3/24;
- Completion unit rigs up and enters well 3/31;
- Completion unit released 4/1;
- Dig frac pit, fill with water; also bring in frac tanks and preparatory work 4/2 through 4/17;
- Frac well (first stage) 4/18 through 4/19;
- Well testing and flowback crew work 4/20 through 4/22;
- Frac well (second stage) 4/23;
- Well testing and flowback crew work 4/24 through 5/8;
- Frac well (third stage) 5/9;
- Well testing and flowback crew work 5/10 through 5/15.

Solution

Charge 55 days. Under the 2005 Model Form Accounting Procedure (and all post COPAS 1974 onshore model form accounting procedure provisions), drilling overhead qualifies for 3/1 through 4/23 and on 5/9. The frac preparatory work between 4/2 and 4/17 qualifies for drilling overhead because the well was sustaining some type of completion activity. Even though it is a production operation, the 4/20 through 4/22 testing/flowback period is eligible for drilling overhead because the suspension period between the first and second fracs is less than 15 days. The 4/24 through 5/8 period is not eligible for drilling overhead because it is a production operation whose duration is greater than 14 days, thereby making it a suspension period not eligible for drilling overhead. The 5/10 through 5/15 flowback/testing period is not eligible for drilling overhead because it is a production operation. However, the frac on 5/9 does qualify because it is part of the initial completion operation, so the five consecutive work day rule for workovers does not apply.

Refer to Section II.C.

Example 17

Assumptions

- COPAS 2005 Model Form Accounting Procedure;
- Workover rig enters well 8/1 and is released 8/3;
- Frac tank setting/filling and preparatory work 8/13 through 8/20;
- Frac well 8/21 to 8/22;
- Coil tubing rig cleans out well 8/23.

Solution
Charge 23 days from 8/1 through 8/23. Under the COPAS 2005 Model Form Accounting Procedure (and all post COPAS 1968 onshore model form accounting procedure provisions), drilling overhead begins when the workover commences (well is entered per Section II. E.). Even though the workover rig was only on the well four days, the period 8/13 through 8/23 meets the five-consecutive work day rule because the well was sustaining some type of workover activity.

Also, the period between the workover rig release and frac equipment arrival was nine days (8/4 through 8/12), which is within the 14-day suspension requirement.

Refer to Sections II.C. and II.E.

Example 18

Assumptions
- COPAS 2005 Model Form Accounting Procedure;
- Frac tank setting/filling and preparatory work 9/1 through 9/10;
- Workover rig enters well 9/11 and is released 9/12;
- Frac well 9/13;
- Coil tubing rig cleans out well 9/14.

Solution
No drilling overhead should be charged because the COPAS 2005 Model Form Accounting Procedure (and all post-COPAS 1974 onshore model form accounting procedure provisions) requires five consecutive work days for a workover to be eligible. The workover commenced on 9/11 when the rig entered the well and concluded on 9/14 upon rig release, thus lasting only four days. If the coil tubing unit was on the well for 9/14 and 9/15, there would be five consecutive work days and drilling overhead would be charged from commencement (well entered). The frac equipment and preparatory work days would not qualify since it occurred prior to the workover commencement date.

Refer to Sections II.C. and II.E.

EXHIBIT 1

COPAS MODEL FORM ACCOUNTING PROCEDURES
DRILLING OVERHEAD PROVISIONS

COMBINED FIXED RATES

These are all direct quotes from the COPAS model form accounting procedures noted.

COPAS 1962 MODEL FORM ACCOUNTING PROCEDURE

Charges for drilling wells shall begin on the date each well is spudded and terminate on the date the drilling or completion rig is released, whichever is later, except that no charge shall be made during the suspension of drilling operations for fifteen (15) or more consecutive days.

Wells being plugged back, drilled deeper, converted to a source or input well, or which are undergoing any type of workover that requires the use of a drilling or workover rig shall be considered the same as drilling wells.

COPAS 1968 MODEL FORM ACCOUNTING PROCEDURE
Charges for drilling wells shall begin on the date each well is spudded and terminate on the date the drilling or completion rig is released, whichever is later, except that no charge shall be made during the suspension of drilling operations for fifteen (15) or more consecutive days.

Wells being plugged back, drilled deeper, converted to a source or input well, or which are undergoing any type of workover that requires the use of a drilling rig or workover rig capable of drilling shall be considered the same as drilling wells.

COPAS 1974 MODEL FORM ACCOUNTING PROCEDURE
Charges for onshore drilling wells shall begin on the date the well is spudded and terminate on the date the drilling or completion rig is released, whichever is later, except that no charge shall be made during suspension of drilling operations for fifteen (15) or more consecutive days.

Charges for offshore drilling wells shall begin on the date when drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location or rig is released, whichever occurs first, except that no charge shall be made during suspension of drilling operations for fifteen (15) or more consecutive days.

Charges for wells undergoing any type of workover or recompletion for a period of five (5) consecutive days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations, with rig, commence through date of rig release, except that no charge shall be made during suspension of operations for fifteen (15) or more consecutive days.

COPAS 1976 OFFSHORE MODEL FORM ACCOUNTING PROCEDURE

Charges for drilling wells shall begin on the date when drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location or rig is released, whichever occurs first, except that no charge shall be made during suspension of drilling operations for fifteen (15) or more consecutive days.

Charges for wells undergoing any type of workover or recompletion for a period of five (5) consecutive days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations with rig or wireline unit commence through date of rig or wireline unit release, except that no charge shall be made during suspension of operations for fifteen (15) or more consecutive days.

COPAS 1984 MODEL FORM ACCOUNTING PROCEDURE

Charges for drilling wells shall begin on the date the well is spudded and terminate on the date the drilling rig, completion rig, or other units used in completion of the well is released, whichever is later, except that no charge shall be made during suspension of drilling or completion operations for fifteen (15) or more consecutive calendar days.

Charges for wells undergoing any type of workover or recompletion for a period of five (5) consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations, with rig or other units used in workover, commence through date of rig or other unit release, except that no charge shall be made during suspension of operations for fifteen (15) or more consecutive calendar days

COPAS 1986 OFFSHORE MODEL FORM ACCOUNTING PROCEDURE

Charges for drilling wells shall begin on the date when drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location or rig is released, whichever occurs first, except that no charge shall be made during suspension of drilling operations for fifteen (15) or more consecutive calendar days.

Charges for wells undergoing any type of workover or recompletion for a period of five (5) consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations, with rig or other units used in workover, commence through date of rig or other unit release, except that no charge shall be made during suspension of operations for fifteen (15) or more consecutive calendar days.

COPAS 1995 MODEL FORM ACCOUNTING PROCEDURE

Charges for onshore drilling wells shall begin on spud date and terminate on the date the drilling or completion equipment is released, whichever occurs later. Charges for offshore drilling wells shall begin on the date drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location or the rig is released, whichever occurs first. No charge shall be made during suspension of drilling or completion operations for 15 or more consecutive calendar days.

Charges for wells undergoing any type of workover, recompletion, or abandonment for a period of five consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from the date workover operations, with the rig or other units used in workover, commence through the date of the rig or other unit release, except that no charges shall be made during suspension of operations for 15 or more consecutive calendar days.

COPAS 1998 PROJECT TEAM MODEL FORM ACCOUNTING PROCEDURE

Charges for onshore drilling wells shall begin on spud date and terminate on the date the drilling or completion equipment is released, whichever occurs later. Charges for offshore drilling wells shall begin on the date the drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location or rig is released, whichever occurs first. No charge shall be made during suspension of drilling or completion operations for 15 or more consecutive calendar days.

Charges for wells undergoing any type of workover, recompletion, or abandonment for a period of five consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from date workover operations, with rig or other units used in workover, commence through date of rig or other unit release, except that no charges shall be made during suspension of operations for 15 or more consecutive calendar days.

COPAS 2005 MODEL FORM ACCOUNTING PROCEDURE

Charges for onshore drilling wells shall begin on the spud date and terminate on the date the drilling and/or completion equipment used on the well is released, whichever occurs later. Charges for offshore and inland waters drilling wells shall begin on the date the drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location, or is released, whichever occurs first. No charge shall be made during suspension of drilling and/or completion operations for fifteen (15) or more consecutive calendar days.

Charges for any well undergoing any type of workover, recompletion, and/or abandonment for a period of five (5) or more consecutive work days shall be made at the Drilling Well Rate. Such charges shall be applied for the period from date operations, with rig or other units used in operations, commence through date of rig or other unit release, except that no charges shall be made during suspension of operations for fifteen (15) or more consecutive calendar days.

EXHIBIT 2

COPAS MODEL FORM ACCOUNTING PROCEDURES
DRILLING OVERHEAD PROVISIONS

PERCENTAGE OVERHEAD PROVISIONS

These are all direct quotes from the COPAS model form accounting procedures noted.

COPAS 1962 MODEL FORM ACCOUNTING PROCEDURE

Not applicable.

COPAS 1968 MODEL FORM ACCOUNTING PROCEDURE

Development:

_____ Percent (%) of the cost of development of the Joint Property exclusive of costs provided under Paragraph 8 of Section II and all salvage credits.

Operating:

_____ Percent (%) of the cost of operating the Joint Property exclusive of costs provided under Paragraphs 1 and 8 of Section II, all salvage credits, the value of injected substances purchased for secondary recovery and all taxes and assessments which are levied, assessed and paid upon the mineral interest in and to the Joint Property.

For the purposes of determining charges on a percentage basis under Paragraph 1B (2) or Paragraph 3 of this Section III, Development shall include all costs in connection with drilling, redrilling, deepening or any remedial operations on any or all wells involving the use of drilling crew and equipment; also, preliminary expenditures necessary in preparation for drilling and expenditures incurred in abandoning when well is not completed as a producer; and original cost of construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, except Major Construction as defined in Paragraph 6 of this Section III. All other costs shall be considered as Operating.

COPAS 1974 MODEL FORM ACCOUNTING PROCEDURE
Development:

_____ Percent (%) of the cost of Development of the Joint Property exclusive of costs provided under Paragraph 9 of Section II and all salvage credits.

Operating:

_____ Percent (%) of the cost of Operating the Joint Property exclusive of costs provided under Paragraphs 1 and 9 of Section II, all salvage credits, the value of injected substances purchased for secondary recovery and all taxes and assessments which are levied, assessed and paid upon the mineral interest in and to the Joint Property.

For the purposes of determining charges on a percentage basis under Paragraph 1B of this Section III, development shall include all costs in connection with drilling, redrilling, deepening or any remedial operations on any or all wells involving the use of drilling crew and equipment; also, preliminary expenditures necessary in preparation for drilling and expenditures incurred in abandoning when the well is not completed as a producer; and original cost of construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, except Major Construction as defined in Paragraph 2 of this Section III. All other costs shall be considered as Operating.

COPAS 1976 OFFSHORE MODEL FORM ACCOUNTING PROCEDURE
Development:

_____ Percent (%) of the cost of Development of the Joint Property exclusive of costs provided under Paragraph 9 of Section II and all salvage credits.

Operating:

_____ Percent (%) of the cost of Operating the Joint Property exclusive of costs provided under Paragraphs 1 and 9 of Section II, all salvage credits, the value of injected substances purchased for secondary recovery and all taxes and assessments which are levied, assessed and paid upon the mineral interest in and to the Joint Property.

For the purposes of determining charges on a percentage basis under Paragraph 1B of this Section III, development shall include all costs in connection with drilling, redrilling, deepening or any remedial operations on any or all wells involving the use of drilling crew and equipment; also, preliminary expenditures necessary in preparation for drilling and expenditures incurred in abandoning when the well is not completed as a producer; and original cost of construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, except Major Construction as defined in Paragraph 2 of this Section III. All other costs shall be considered as Operating except that catastrophe costs shall be assessed overhead as provided in Section III, Paragraph 3.

COPAS 1984 MODEL FORM ACCOUNTING PROCEDURE

Development:

_____ Percent (%) of the cost of development of the Joint Property exclusive of costs provided under Paragraph 10 of Section II and all salvage credits.

Operating:

_____ Percent (%) of the cost of operating the Joint Property exclusive of costs provided under Paragraphs 2 and 10 of Section II, all salvage credits, the value of injected substances purchased for secondary recovery and all taxes and assessments which are levied, assessed and paid upon the mineral interest in and to the Joint Property.

For the purposes of determining charges on a percentage basis under Paragraph 1B of this Section III, development shall include all costs in connection with drilling, redrilling, deepening or any remedial operations on any or all wells involving the use of drilling rig and crew capable of drilling to the producing interval on the Joint Property; also, preliminary expenditures necessary in preparation for drilling and expenditures incurred in abandoning when the well is not completed as a producer, and original cost of construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, except Major Construction as defined in Paragraph 2 of this Section III. All other costs shall be considered as operating.

COPAS 1986 OFFSHORE MODEL FORM ACCOUNTING PROCEDURE
Development:

_____ Percent (%) of the cost of Development of the Joint Property exclusive of costs provided under Paragraph 9 of Section II and all salvage credits.

Operating:

_____ Percent (%) of the cost of Operating the Joint Property exclusive of costs provided under Paragraphs 1 and 9 of Section II, all salvage credits, the value of injected substances purchased for secondary recovery and all taxes and assessments which are levied, assessed and paid upon the mineral interest in and to the Joint Property.

For the purposes of determining charges on a percentage basis under Paragraph 1B of this Section III, development shall include all costs in connection with drilling, redrilling, deepening of any or all wells, and shall also include any remedial operations requiring a period of five (5) consecutive work days or more on any or all wells; also, preliminary expenditures necessary in preparation for drilling and expenditures incurred in abandoning when the well is not completed as a producer; and original cost of construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, except Major Construction as defined in Paragraph 2 of this Section III. All other costs shall be considered as Operating except that catastrophe costs shall be assessed overhead as provided in Section III, Paragraph 3.

COPAS 1995 MODEL FORM ACCOUNTING PROCEDURE

Development rate _____ percent (%) of the cost of development of the Joint Property exclusive of costs provided under Section IV, Paragraph 3 and all salvage credits.

Operating rate _____ percent (%) of the cost of operating the Joint Property exclusive of costs provided under Section III, Paragraph 1 and Section IV, Paragraph 3; all salvage credits; the value of injected substances purchased for secondary recovery; and all taxes and assessments that are levied, assessed and paid upon the mineral interest in and to the Joint Property.

Application of overhead – percentage basis shall be as follows:
(a) Development shall include all costs in connection with:
- [1] drilling, redrilling, plugging back or deepening of any or all wells
- [2] workover operations requiring a period of five consecutive work days or more on any or all wells
- [3] preliminary expenditures necessary in preparation for drilling
- [4] expenditures incurred in abandoning when the well is not completed as a producer
- [5] original construction or installation of fixed assets, expansion of fixed assets, and any other project clearly discernible as a fixed asset, except major construction as defined in Section V, Paragraph 2.

(b) Operating shall include all other costs in connection with Joint Operations except that catastrophe costs shall be assessed overhead as provided in Section V, Paragraph 2.

COPAS 1998 PROJECT TEAM MODEL FORM ACCOUNTING PROCEDURE

Development Rate _____ Percent (%) of the cost of development of the Joint Property exclusive of costs provided under Section II, Paragraph 9, all salvage credits, and all Project Team expenses and overhead.

Operating Rate _____ Percent (%) of the cost of operating the Joint Property exclusive of costs provided under Section II, Paragraphs 1 and 9; all salvage credits; the value of injected substances purchased for enhanced recovery; and all property and ad valorem taxes and any other taxes and assessments that are levied, assessed and paid upon the mineral interest in and to the Joint Property.

Application of Overhead – Percentage Basis shall be as follows:
(a) Development rate shall be applied to all costs in connection with:
- [1] drilling, redrilling, plugging back, sidetracking or deepening of a well
- [2] workover operations requiring a period of 15 consecutive work days or more on a well
- [3] preliminary expenditures necessary in preparation for drilling
- [4] expenditures incurred in abandoning when the well is not completed as a producer

[5] original construction or installation of fixed assets, expansion of fixed assets, and any other project clearly discernible as a fixed asset, except Major Construction as defined in Section III, Paragraph 3 or any Project Team expenses and overhead.

(b) Operating rate shall be applied to all other costs in connection with Joint Operations except those subject to Section III, Paragraphs 1 and 3.

COPAS 2005 MODEL FORM ACCOUNTING PROCEDURE

Development Rate ____ Percent (%) of the cost of development of the Joint Property, exclusive of costs provided under Section II.9 (Legal Expense) and all Material salvage credits.

Operating Rate _____Percent (%) of the cost of operating the Joint Property, exclusive of costs provided under Sections II.1 (Rentals and Royalties) and II.9 (Legal Expense); all Material salvage credits; the value of substances purchased for enhanced recovery; all property and ad valorem taxes, and any other taxes and assessments that are levied, assessed, and paid upon the mineral interest in and to the Joint Property.

Application of Overhead - Percentage Basis shall be as follows:
(a) The Development Rate shall be applied to all costs in connection with:
[i] drilling, redrilling, sidetracking, or deepening of a well
[ii] a well undergoing plugback or workover operations for a period of five (5) or more consecutive workdays
[iii] preliminary expenditures necessary in preparation for drilling
[iv] expenditures incurred in abandoning when the well is not completed as a producer
[v] construction or installation of fixed assets, the expansion of fixed assets and any other project clearly discernible as a fixed asset, other than Major Construction or Catastrophe as defined in Section III.2 (*Overhead-Major Construction and Catastrophe*).
(b) The Operating Rate shall be applied to all other costs in connection with Joint Operations, except those subject to Section III.2 (*Overhead-Major Construction and Catastrophe*).

Turning Energy Into Synergy

Overhead Adjustment Index Change

MODEL FORM INTERPRETATION 50

Publication/Revision Date - April 2004

Council Approved

PRUTCOM Reviewed January 28, 2025

Introduction

The objective of this document is to provide guidance to the industry regarding a replacement index for use in calculating the annual overhead adjustment under COPAS model form accounting procedures. A replacement index would also be used for other economic factors that have been traditionally adjusted using the same index as the overhead rates, such as the loading/unloading rates under certain COPAS model form accounting procedures. This Model Form Interpretation ("MFI") pertains to the COPAS model form accounting procedures and does not supersede or override the provisions of any other written agreements.

Problem

The COPAS 1962, 1968, 1974, 1976 Offshore, 1984, and 1986 Offshore Model Form Accounting Procedures provide that administrative overhead or combined fixed rate drilling and producing overhead be adjusted each year by the annual change in an index referred to as either the Average Weekly Earnings of Crude Petroleum and Gas Production Workers or the Average Weekly Earnings of Crude Petroleum and Gas Field Production Workers (Prior Index) as published by the United States Department of Labor, Bureau of Labor Statistics ("BLS") or the equivalent Canadian index as published by Statistics Canada, as applicable. The BLS has converted all of its industry-based statistics from the Standard Industry Classification ("SIC") system to the North American Industry Classification System ("NAICS"). The NAICS was developed in cooperation with the United States' North American Free Trade Agreement partners to standardize codes across Canada, U.S., and Mexico, allowing a direct comparison of economic data across North America. As a result of the conversion, the BLS is no longer publishing the Crude Petroleum and Natural Gas Workers Index by its former name after March 2003. Accordingly, the last complete year for the Crude Petroleum and Natural Gas Workers Index was 2002, which was used to provide the COPAS overhead adjustment factor effective April 1, 2003.

Although the Canadian index continues to be published by Statistics Canada, the reference to the Canadian index in the COPAS model form accounting procedures is intended to address those situations where the form is used for a Canadian operation. Accordingly, the Canadian index is not applicable to properties located in the United States and a replacement index is needed for U.S. properties.

According to the BLS, 95.9% of the Prior Index (10-1310) historically used by COPAS was mapped to the Oil and Gas Extraction Index (10-211000), while approximately 2.9% of it was mapped to Management of Companies and Enterprises (60-550000) and another 1.2% was mapped to Accounting and Bookkeeping Services (10-541200). Conversely, the Oil and Gas Extraction Index (10-211000) is comprised of the Prior Index (10-1310) and the Natural Gas Liquids Index (10-1320), contributing 96.3% and 3.0%, respectively. Exhibit 1 illustrates this mapping. The level of interchangeability can be determined by multiplying the percent of employment from a given SIC series that was converted to a NAICS series by the percent of employment in a given NAICS series that came from a given SIC series. Given the above conversion rates, the Prior

Index and the Oil and Gas Extraction Index are 92.4% interchangeable. The most significant component missing from the Oil and Gas Extraction Index is overhead items such as:

- Legal services,
- Accounting, tax preparation, bookkeeping, and payroll services,
- Engineering services,
- Geophysical surveying and mapping services,
- Computer systems design and related services,
- Human resources and executive search consulting services,
- Other services traditionally considered by COPAS model form accounting procedures as covered by overhead.

Another BLS published index, the Professional and Technical Index, includes the above overhead items and may be more reflective of changes in overhead costs than the Oil and Gas Extraction Index alone, which does not consider management and accounting wages. The percent change in the simple average labor dollars in the Oil and Gas Extraction Index and the Professional and Technical Index (overhead adjustment index) provides results most closely matching the historical results of the Prior Index. Exhibit 2, Index Rate Comparison, compares the above-mentioned rates and demonstrates the calculation of the new index (overhead adjustment index) based on historical BLS information for the converted indices back to 1992. Over the period from 1992 through 2002, the proposed Overhead Adjustment Index differs by only 0.13% (31.77% for the proposed index verses 31.90% for the Prior Index). Independently, both the Oil and Gas Extraction Index and the Professional and Technical Index created much larger variances over the same period.

CONCLUSION

COPAS believes that the percent change in the simple average labor dollars in the Oil and Gas Extraction Index and the Professional and Technical Index provides results most closely matching the historical results of the Prior Index. Effective for the April 1, 2004, overhead adjustment, COPAS will calculate and make available the percentage change in the 2002 and 2003 data for the overhead adjustment index. In addition, future years' adjustments will be calculated using the same index. Because the Prior Index is no longer published by the BLS, parties to agreements that incorporate the COPAS 1962, 1968, 1974, 1976 Offshore, 1984, and 1986 Offshore Model Form Accounting Procedures should consult with their legal and financial advisors regarding whether or not to amend such agreements to use the overhead adjustment index or some other mutually acceptable index.

Exhibit 1

BLS Conversions

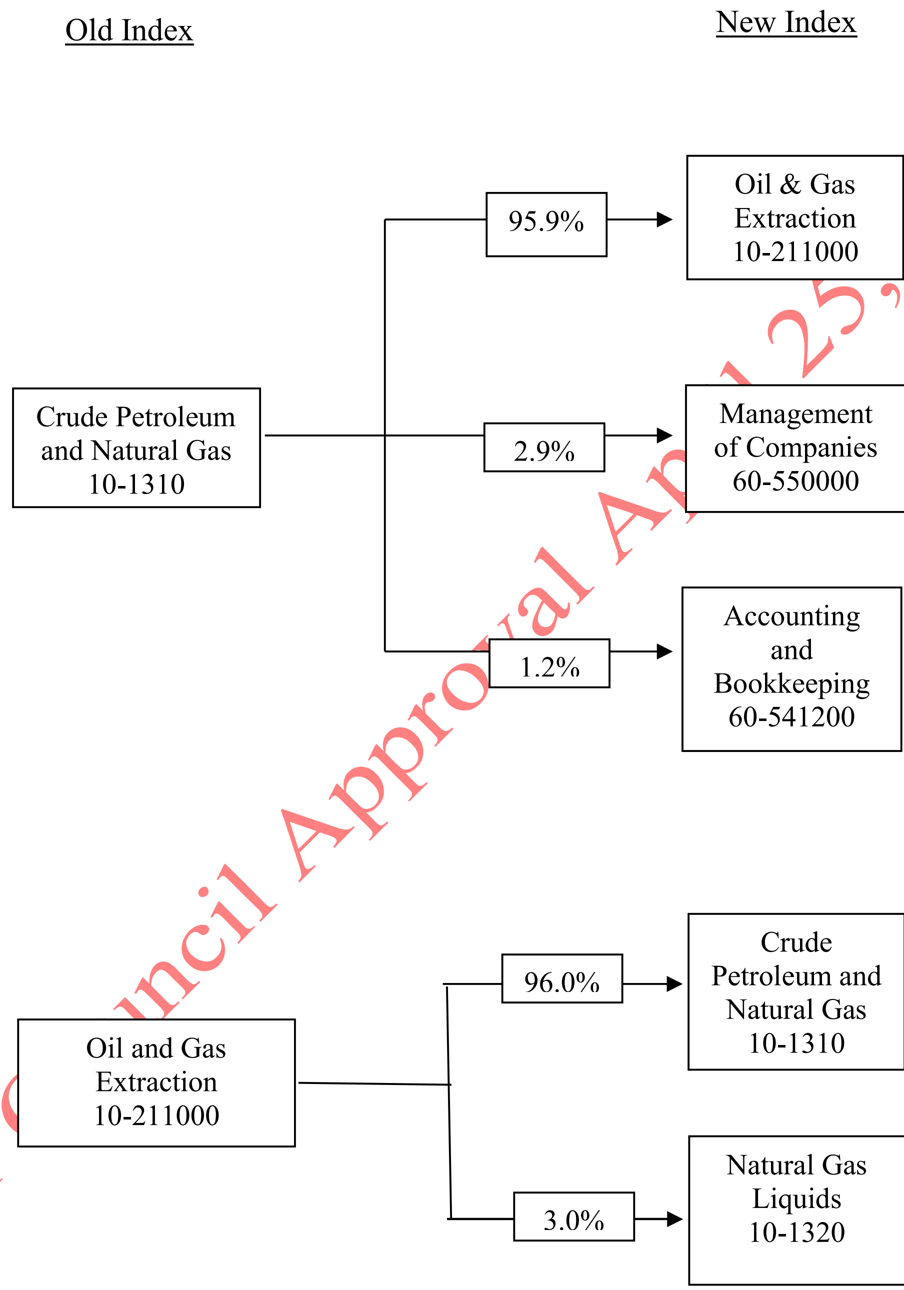

Exhibit 2

Index Rate Comparison

	Prior Index	Oil and Gas Extraction Index		Professional and Technical Index		Overhead Adjustment Index: Oil and Gas Extraction Index Plus Professional and Technical Index	
Year	Annual Percentage	Labor Costs	Annual Percentage	Labor Costs	Annual Percentage	Average Combined Labor Costs	Annual Percentage
1992		$596.49		$536.84		$566.67	
1993	4.80%	621.96	4.27%	548.91	2.25%	585.44	3.31%
1994	4.40%	650.46	4.58%	565.67	3.05%	608.07	3.87%
1995	4.10%	676.74	4.04%	583.41	3.14%	630.08	3.62%
1996	2.00%	693.93	2.54%	607.30	4.09%	650.62	3.26%
1997	10.30%	757.87	9.21%	645.92	6.36%	701.90	7.88%
1998	5.80%	802.70	5.92%	682.46	5.66%	742.58	5.80%
1999	-0.50%	801.89	-0.10%	714.68	4.72%	758.29	2.11%
2000	6.00%	802.03	0.02%	745.83	4.36%	773.93	2.06%
2001	-1.90%	825.25	2.90%	769.63	3.19%	797.44	3.04%
2002	-3.10%	760.64	-7.83%	783.46	1.80%	772.05	-3.18%
10-Year Change Total	31.90%		25.55%		38.62%		31.77%
10-Year Change vs COPAS			-6.35%		6.72%		-0.13%