Spring 2023 National Meeting
Emerging Issues Sub-Committee Agenda
Kansas City, MO (in person)
Wednesday, April 26, 2023 | 8:00 AM – 12:00 PM CST

TIME (CST)	AGENDA ITEM	DISCUSSION LEADERS
8:00	Welcome and Introductions Attendee Introductions First Timer Recognition	Lucas Vaughn / Carole Tear
8:10	**Emerging Issues in the Oil and Gas Industry** Antitrust Statement & EI Disclaimer Meeting Overview	

This is a seminar session, consisting of guided case studies, small group discussion, and review on issues affecting the oil & gas industry. Discussion will focus on potential issues around accounting for the costs related to these emerging issues.

Learning Objectives:

By the end of this session you will be able to:

1. Discuss legislative/legal situations impacting the industry.
2. Describe and discuss the 24-month adjustment period.
3. Recall how to interact with different stakeholders during an audit.
4. Engage in meaningful discussion on certain issues and situations in the oil & gas accounting industry.

Program Level:	Intermediate
Pre-requisites:	Familiarity with COPAS publications and general accounting standards
Advance Preparation:	Read the EI Case Studies handout
Delivery Method:	Group Live
Field of Study:	Specialized Knowledge
CPE Credits:	4.0

8:15	**TOPIC ONE: TBD Speaker** Guest Presentation TBD.	TBD Guest Speaker
9:15	**TOPIC TWO: Overhead Exceptions & Corrections**	Lucas Vaughn / Carole Tear
10:00	Break	
10:20	**TOPIC THREE: Responsibly Sourced Gas Certification**	Lucas Vaughn / Carole Tear
10:50	**TOPIC FOUR: Shared Well Pad Drilling Overhead**	Lucas Vaughn / Carole Tear

11:20 TOPIC FIVE: Electrifying Situations Lucas Vaughn / Carole Tear

11:50 Member Remarks/Discussion & Closing Thoughts Lucas Vaughn / Carole Tear

12:00 Adjourn

The COPAS Emerging Issues Sub-Committee is an open communications forum for expressing opinions and ideas relating to industry joint interest accounting and audit issues. These discussions, including any expression of ideas and results of straw polls, do not represent individual company positions, industry consensus or COPAS endorsement or policy. These discussions should not be represented as being industry policy or as being endorsed by COPAS in any forum or writing.

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<u>COPAS Spring National 2023 EI Case Study: Overhead Exceptions & Corrections</u>

Producing Overhead

An audit is completed in December 2022 on charges from 2020 & 2021. The auditor found the Joint Account was charged for Producing Overhead ("POH") as shown below, and the JOA, dated 01/01/2020, lists the Producing Overhead rate as $700/month.

Year/Month	1	2	3	4	5	6	7	8	9	10	11	12
2020	600	600	600	1500	750	750	750	750	750	750	750	750
2021	750	750	750	775	775	775	775	775	775	775	775	775

<u>Questions</u>:

1. The Auditor is only taking exception to the month 4 POH as a duplicate charge. What are the Operator's options to correct this situation in 2023 and why?
    a. Correct only month 4 2020 POH charge to $750.
    b. Correct only month 4 2020 POH charge to $600.
    c. Correct only month 4 2020 POH charge to $725.
    d. Correct POH charges for months 1 2020 through 4 2020 to the correct escalated/de-escalated rates.
    e. Correct all months POH charges to the correct escalated/de-escalated rates.
    f. Do your answers change if the Operator is making the corrections in December 2022?

2. The Auditor is only taking exception to the month 5 POH rate of $750, as the COPAS escalation factor in 2020 shows the rate should have been escalated from $700 to $725. What are the Operator's options to correct this situation in 2023 and why?
    a. Correct only month 5 2020 POH charge to $725.
    b. Correct POH charges for months 4 2020 through 3 2021 to $725.
    c. Correct months 01 2020 through 04 2020 to $700.
    d. Correct all months to the correct escalated/de-escalated rates.
    e. Do your answers change if the Operator is making the corrections in December 2022?

Drilling Overhead

An audit is completed in December 2022 on charges from 2020 & 2021. The auditor found the Joint Account was charged for Drilling Overhead ("DOH") as shown below, and the JOA, dated 01/01/2020, lists the DOH rate as $6500/month.

Year 2020	1	2	3	4	5	6	7	8	9	10	11	12
Activity Days					15	30	10					
Billed Days					15	30	2					
OH @ 6500/mo					$ 3,145	$ 6,500	$ 419					
OH @ 7000/mo					$ 3,387	$ 7,000	$ 452					

<u>**Question**</u>:

1. The auditor found the Operator used a rate of $7,000/month when calculating DOH charges, and the auditor takes exception to the DOH rate. What are the Operator's options to correct this situation in 2023 and why?
   a. Correct DOH charges for months 5 through 7 by adjusting the DOH rate only.
   b. Correct DOH charges for months 5 through 7 by adjusting the rate and by correcting the number of billed days in month 7 to 10.
   c. Correct DOH rate as in option A, but add the missed billed days to a different Joint Account.
   d. Do your answers change if the Operator is making the corrections in December 2022?

Major Construction Overhead

An audit is completed in December 2022 on charges from 2020 & 2021. The auditor found the Joint Account was charged for Major Construction Overhead ("MCOH") at the rate indicating engineering, drafting, and design were to be covered by overhead (i.e. the higher percentages). The auditor identified an engineering related invoice charged to the Joint Account that was included in the MCOH cost pool. The auditor took exception to MCOH charges, requesting the "lower percentages" (meaning engineering invoices will be charged direct) be applied to the MCOH cost pool.

After review of the exception, the Operator identified 5 engineering invoices related to the Major Construction project that were not charged to the Joint Account. What are the Operator's options to correct this situation in 2023?

1. Credit Joint Account for the engineering invoice and do not change the MCOH percentage used (stay with higher percentage).
2. Change to the lower MCOH percentage, and do not make any adjustments to the MCOH cost pool or Joint Account.
3. Charge the Joint Account for the recently found 5 "missing" engineering invoices and include them in the MCOH cost pool, and also switch to the lower MCOH percentages.
4. Include the recently found 5 "missing" invoices in the MCOH cost pool and calculation, but do not charge those invoices to the Joint Account, and change the MCOH to the lower percentage.
5. Do your answers change if the Operator is making the corrections in December 2022?

<u>COPAS Spring National 2023 EI Case Study: RSG Certifications</u>

Facts

Jones Operating operates wells in Area A. Smith Operating operates other wells in Area A, in which Jones Operating is a TIK non-operating partner. Fringe Resources is a non-operator in both Jones- and Smith-operated wells. Fringe is TIK on some wells, and the operator markets for them on some.

Jones employs consultants, obtains services, and purchases equipment to gain certification for Responsibly Sourced Gas. The certification also includes costs of ongoing monitoring and compliance. The gas sells at a market premium and is also targeted by purchasers with advanced environmental requirements or goals. In addition, there may be carbon credits resulting from the certification, and unused RSG certificates themselves can be purchased in a marketplace, similar to carbon credits.

RSG certification equipment and services monitor and report emissions and safety metrics at the well sites, but it also supports achievement of Jones' ESG (corporate responsibility) goals. Jones' wells are governed by a 2005 Accounting Procedure. Other wells may be subject to other agreements.

Scenario 1

The RSG certification covers all Area A wells operated by Jones. All gas produced from Jones' Area A wells could receive the benefit of the certification.

1. Should we as an industry encourage (or require) third party RSG certification companies to develop a way to share the benefit of RSG certified production with non-operators who market their own gas (TIK)?

2. Should non-operators who TIK share in the cost of certification?
    a. Onsite emissions monitoring equipment
    b. Monthly monitoring services
    c. Consulting and engineering review/mitigation activities
    d. Annual third-party fees for well-level audits/assessments required to maintain certification

3. For billing purposes, do these activities resemble any the following?
    a. Allocated or direct Individual well costs
    b. Operator owned equipment charged through a fee – what would establish "Market" rates?
    c. Separate jointly owned facility (separate AFE/approval/agreement) –
        i. Could a party receiving benefit opt out?
        ii. Is the certification on individual wells or is it considered a single project?
    d. Operator's sole cost – such as Lobbying or Community Relations (PR)
    e. Covered by overhead – Preparation and monitoring of permits and certifications
    f. Marketing or GP&T – How would this impact TIK owners? Royalty owners?

Scenario 2

Same situation as Scenario 1, however only the gas marketed by Jones Operating is certified. TIK production meets the same ESG standards, but does not receive certification through the operator. The TIK owner may (or may not) be able to obtain certification separately.

1. Should we as an industry encourage (or require) third party RSG certification companies to develop a way to share the benefit of RSG certified production with non-operators who market their own gas (TIK)?

2. Should non-operators who TIK share in the cost of certification?
    a. Onsite emissions monitoring equipment
    b. Monthly monitoring services
    c. Consulting and engineering review/mitigation activities
    d. Annual third-party fees for well-level audits/assessments required to maintain certification

Scenario 3

Jones Operating is certified on its operated wells, but to meet ESG goals and receive a better pricing on TIK volumes, Jones would like Smith Operating to be certified as well.

1. Should non-operators encourage operators to seek certification for marketed volumes? For TIK volumes? Do they have any options or leverage in encouraging certification?

Scenario 4

The RSG certification covers all Area A wells operated by Jones. There is a market for unused RSG certifications. Jones chooses to sell unused certifications on the RSG market.

1. Can an operator sell unused RSG certifications related to its own production?
2. Can an operator sell unused RSG certifications related to production for marketed owners? Are they required to? Are they required to notify the non-operator of any unused certificates?
3. Can an operator sell unused RSG certifications related to production for TIK owners? Are they required to? Are they required to notify the non-operator of any unused certificates?

COPAS Spring National 2023 EI Case Study: Shared Well Pad/Multi-Well Drilling Overhead

Facts
Operator "ABC" plans to drill 4 wells on a single drill pad site using an assembly line approach. The plan they use assumes no downtime and SIMOPS (simultaneous operation). The operator uses the same design and specs for every well. The rig is skid mounted and can quickly slide to the next well on the pad without having to rig down or rig up.

ABC is being audited by a group of non-operators who have identified what they believe is a significant audit exception based on the "fair and equitable" principle, but they can't seem to support their position with current COPAS publications, including MFI-51, *COPAS 2005 Model Form Accounting Procedure Interpretation*, MFI-48, *Application and Calculation of Drilling Overhead*, and AG-29, *Shared Well Pad Cost Allocations*.

See attached simplified example of calculating drilling overhead on a shared well pad. In this example, four wells are drilled, acidized, and fracked between July 1 and August 4.

Assumptions
Keep the following assumptions in mind for reviewing this case:
- The prevailing JOA has COPAS 2005 as Exhibit C
- Effective date of the prevailing JOA is January 1, 2020
- Period being audited during 2022 is 2021
- Effective drilling rate on the effective date of the agreement is $10,000, escalated Overhead is accurately calculated t $10,614.71.
- Wells in question are onshore and being drilled from a single well pad
- There is no "suspension of operations" on any of these wells during the drilling operations
- There are no isolation activities on off-pad wells

Questions

1. **Can the auditors base a valid audit exception on the equity principle?**
    a. No, the auditors must identify a contractually based argument before submitting the exception.
    b. Yes, equity, unjust enrichment, and other conceptual arguments provide legal justification for exceptions.
    c. Yes, the auditor can take any exception they desire, but operators are only legally required to fulfill the contractual terms of the agreement.

2. **Can an operator charge the joint account based on the equity principle?**
    a. No, the operator must identify a contractually based argument before charging the joint account.
    b. Yes, equity, unjust enrichment, and other conceptual arguments provide legal justification for charges.
    c. Yes, the operator can charge anything they desire, but operators must issue credit for exceptions based on the contractual terms of the agreement.

3. **Based on the prevailing COPAS model form and MFI-48 principles, the Operator's recovery of drilling overhead for all 4 wells is appropriate.**
    a. Is this assessment fair and equitable?   - Yes/No
    b. Are additional overhead activities performed for Well B, C & D, that weren't already performed for Well A? - Yes/No
    c. If the answer above was yes, what OH activities overlap (are shared by the wells), and what activities do not?

        - design and drafting…
        - inventory costs not chargeable…
        - procurement
        - administration
        - accounting and auditing
        - gas dispatching and gas chart integration
        - human resources
        - management
        - supervision not directly charged…
        - legal services not directly chargeable…
        - taxation, other than those costs identified as directly chargeable…
        - preparation and monitoring of permits and certifications; preparing regulatory reports; appearances before or meetings with governmental agencies…

4. **This case study demonstrates significant dollars can be involved when you are dealing with drilling overhead on more than 2 wells, particularly when frac operations are included in the days allowable for calculating overhead.**
    a. Under existing Accounting Procedures, should the Drilling overhead be assessed as if on a single operation, from beginning to end (spud of Well A and rig release for Well D)?   - Yes/No
    b. Would it be more appropriate to create a "shared well pad" activity and then allocate the combined pad activity costs (including overhead at 1 charge per day) to each well based on actual rig days used for each well? – Yes/No
    c. Should COPAS reconsider how drilling overhead should be calculated for shared well pads which include drilling activities for several wells? – Yes/No

Example Overhead Calculation

Date	Activity	Well A	Well B	Well C	Well D		Total OH Days	Pad Active days
30-Jun	Drill rathole/moushole	0	0	0	0		0	0
1-Jul	Spud Well A-set conductor	1	0	0	0		1	1
2-Jul	Spud Well B-set conductor	1	1	0	0		2	1
3-Jul	Spud Well C-set conductor	1	1	1	0		3	1
4-Jul	Spud Well D-set conductor	1	1	1	1		4	1
5-Jul	Skid Rig back to well A	1	1	1	1		4	1
6-Jul	Drill 500' Well A-set surface casing	1	1	1	1		4	1
7-Jul	Drill 500' Well B-set surface casing	1	1	1	1		4	1
8-Jul	Drill 500' Well C-set surface casing	1	1	1	1		4	1
9-Jul	Drill 500' Well D-set surface casing	1	1	1	1		4	1
10-Jul	Skid Rig back to well A	1	1	1	1		4	1
11-Jul	Drill 1000' Well A-set intermediate casing	1	1	1	1		4	1
12-Jul	Drill 1000' Well B-set intermediate casing	1	1	1	1		4	1
13-Jul	Drill 1000' Well C-set intermediate casing	1	1	1	1		4	1
14-Jul	Drill 1000' Well D-set intermediate casing	1	1	1	1		4	1
15-Jul	Skid Rig back to well A	1	1	1	1		4	1
16-Jul	Drill 1500' Well A-set production casing	1	1	1	1		4	1
17-Jul	Drill 1500' Well B-set production casing	1	1	1	1		4	1
18-Jul	Drill 1500' Well C-set production casing	1	1	1	1		4	1
19-Jul	Drill 1500' Well D-set production casing	1	1	1	1		4	1
20-Jul	Rig Released	1	1	1	1		4	1
21-Jul	Perforate well A - Coiled tubing unit	1	1	1	1		4	1
22-Jul	Perforate well B Coiled tubing unit	1	1	1	1		4	1
23-Jul	Perforate well C - Coiled tubing unit	1	1	1	1		4	1
24-Jul	Perforate well D - Coiled tubing unit	1	1	1	1		4	1
25-Jul	Rug up completion rig	1	1	1	1		4	1
26-Jul	Acidize well A, run tubing	1	1	1	1		4	1
27-Jul	Acidize well B, run tubing	1	1	1	1		4	1
28-Jul	Acidize well C, run tubing	1	1	1	1		4	1
29-Jul	Acidize well D, run tubing	1	1	1	1		4	1
30-Jul	Move in Frac equipment	1	1	1	1		4	1
31-Jul	Set tanks/Fill	1	1	1	1		4	1
1-Aug	Set tanks/Fill	1	1	1	1		4	1
2-Aug	Set tanks/Fill	1	1	1	1		4	1
3-Aug	Frac well A, run tubing	1	1	1	1		4	1
4-Aug	Frac well A, run tubing	1	1	1	1		4	1
5-Aug	Frac well A, run tubing	1	1	1	1		4	1
6-Aug	Frac well B, flowback Well A	1	1	1	1		4	1
7-Aug	Frac well B, flowback Well A	1	1	1	1		4	1
8-Aug	Frac well B, flowback Well A	1	1	1	1		4	1
9-Aug	Frac well C, flowback Well B, Acidize Well A	1	1	1	1		4	1
10-Aug	Frac well C, flowback Well B, Acidize Well A	1	1	1	1		4	1
11-Aug	Frac well C, flowback Well B, Acidize Well A	1	1	1	1		4	1
12-Aug	Frac well D, flowback Well C, Acidize Well B, FRR Well A	1	1	1	1		4	1
13-Aug	Frac well D, flowback Well C, Acidize Well B	0	1	1	1		3	1
14-Aug	Frac well D, flowback Well C, Acidize Well B	0	1	1	1		3	1
15-Aug	Flowback Well D, Acidize Well C, FRR Well B	0	1	1	1		3	1
16-Aug	Flowback Well D, Acidize Well C	0	0	1	1		2	1
17-Aug	Flowback Well D, Acidize Well C	0	0	1	1		2	1
18-Aug	Acidize Well D, FRR Well C	0	0	1	1		2	1
19-Aug	Acidize Well D	0	0	0	1		1	1
20-Aug	Acidize Well D	0	0	0	1		1	1
21-Aug	FRR Well D - All off location	0	0	0	1		1	1
22-Aug	All off location	0	0	0	0		0	0
	Total Days	**43**	**45**	**47**	**49**		**184**	**52**
	Active days	20	20	20	20		80	52
	Non-Active Days	23	25	27	29		104	0
Overhead								
$10,614.71	Monthly OH rate							
$ 342.41	Daily OH Rate (31 days/mo)							
	Total Overhead	14,723.63	15,408.45	16,093.27	16,778.09		63,003.44	17,805.32
	Overhead - Active Days per well	6,848.20	6,848.20	6,848.20	6,848.20		27,392.80	

Consider the following during your review of this case:

- A general COPAS principle has always been that overhead is not intended for the Operator to over-recover costs associated with overhead functions performed (e.g., the Operator should not profit from overhead, but be reimbursed for costs associated with activities provided by overhead classified functions).

- It has been acknowledged that there are times the operator will over-recover, and times the operator will under-recover. The overhead rate is intended to be negotiated for each contract and can be adjusted or amended to fit the operational situation.

- Per the COPAS 2005 AP, each well on the shared well pad would qualify for drilling overhead from the time the well is spudded until the rig is released, provided there is not more than fifteen (15) or more consecutive calendar days of suspended operations.

  MFI-51, *COPAS 2005 Model Form Accounting Procedure Interpretation*
  Section III.B.(2)(a) – bolded for added emphasis:

  (2) Application of Overhead—Drilling Well Rate shall be as follows:
  (a) **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

- Per MFI-48, each well qualifies for drilling overhead since there have not been any suspension of operations from the time the wells are spud and the rig used is finally released.

  MFI-48, *Application and Calculation of Drilling Overhead*
  MFI-48, Section III.C, Combined Fixed Rate, Suspension of Operations (page 8-9), includes the following example which aligns closely with the situation in this case study, although a simplified version (bold added for emphasis):

  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	1/1-1/10
Drill Well #2	10	1/11-1/20

Complete Well #1	10	1/21-1/30
Complete Well #2	10	1/31-2/9
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 – 1/30) and Well # 2 attracts 30 days (1/11 – 2/9).

- AG-29 also addresses activities such as those described in the example. While cost savings are described, the AG also alludes to the added complexity and administrative burden in planning and allocating the costs incurred.

  AG-29, *Shared Well Pad Cost Allocations* (Section III.D) states the following (bold added for emphasis):

  D. Rig Moves
  Two main components make up the cost to mobilize a drilling rig: the cost to haul the rig to the location and the cost to assemble the rig for drilling operations. **When multiple wells are going to be drilled on the same pad, it is a common practice to drill the wells consecutively using the same drilling rig. This practice often results in substantial cost savings because there is only one trucking charge to haul the rig to the location**. Then, rather than paying to completely disassemble and reassemble the rig to drill each well, the contractor skids the assembled rig to the next well locations on the pad at a relatively small charge. **The trucking, assembly and subsequent skid costs incurred by the Consecutively Drilled Wells should be pooled and allocated equitably among the Consecutively Drilled Wells.** The first well drilled should not be unfairly penalized simply for being the first well to drill on the pad.

COPAS Spring National 2023 EI Case Study: Electrifying Situations

Part 1: Electrical Infrastructure Grid – Operator Owned Equipment Rate

An Operator is expanding in an area that needs upgrades to the electrical distribution system. The local electric company provided two options for electricity service:

1. $0.15/kWh if the electric provider delivers the electricity to each of the many field locations.
2. $0.08/kWh if Operator builds and operates a substation and distribution network.

The Operator elects the second option and decides to construct and operate their own substation and distribution network. The Operator will expand the distribution network as needed to accommodate more wells and/or facilities that come online. The Operator has several partners with varying interests in the upcoming projects.

Questions:

1. Are the costs to construct this electric substation and distributions network chargeable to a Joint Account? If so, where does this authorization come from and what methods are available to the Operator for use in calculating billing rates?
2. If the Operator decides to bill a Joint Account for the use of the electric infrastructure using average commercial rates less 20% (section II.6.B), which rate would be considered the "average commercial rates" and why?
    a. $0.15/kWh
    b. $0.08/kWh
    c. $0.07/kWh (spread between previous two rates)
    d. There is no market rate because there is no electrical distribution system in the area for comparison (hasn't been built yet)
3. If the Operator decides to bill a Joint Account for using the electrical infrastructure with a rate that represents actual costs of ownership (section II.6.A), what would be the maximum rate they could charge for using this infrastructure (assuming the actual costs supported the rate)?
    a. $0.15/kWh
    b. $0.08/kWh
    c. $0.07/kWh (spread between previous two rates)
    d. There is no limit to the rate that can be charged so long as the rate is supported by Operator's actual costs

Part 2: Flare Gas Usage for Electricity Production

An Operator has several producing wells with flare gas volumes produced each month. The Operator found a vendor that can use the flare gas to power a generator on site to produce electricity for the well at no direct cost to the Operator. The vendor is "paid" by the ability to sell any electricity produced beyond what is required to power the equipment at the well site. There is no cost to the Operator for any installation, equipment, or maintenance of the vendor's equipment.

Questions:

1. Since the flare gas is no longer being flared, does it now have value? If so, what is that value?
2. Are any working interest owners due compensation for this previously flared gas being used by the vendor to produce electricity?
3. Are any royalty owners due compensation for this previously flared gas being used to produce electricity by the vendor?
4. If anyone is due compensation, what rate should be used to determine the compensation?
    a. Market rate for gas sales?
    b. Contract rate with the purchaser for the rest of the gas produced and sold from the well site?
    c. A reduced market rate representative of the gas being used at the well site and not sold?
    d. Some other rate?
5. Since the previously flared gas is now being used to power the well equipment needed for producing oil & gas at the well site, would the Operator be justified in claiming the owners are compensated by the reduction in electricity cost?
6. For the electricity produced in excess of the amount needed at the well site, which is then sold on the electricity market by the vendor, should any owners receive compensation or a share of these sales, either from the vendor or Operator?
    a. If so, how would this be valued?
    b. Does an owner's rights to produced gas trump any terms of a contract between an Operator and the vendor?
7. If the Operator is being fined by the government for excess flare volumes, do any of your answers to the previous questions change? The Operator would now be getting free electricity at any well site where this process is implemented and potentially reduced or eliminated excess flare fines.
8. For a hypothetical comparison, if an Operator was able to use produced oil in a similar manner as flare gas to produce electricity at the well site, would any owners be due compensation for this oil that would have otherwise been sold, but is now being used to offset electricity cost?