SB 2374 HEARING

TESTIMONY PROVIDED BY COREY J DAHL

A LITTLE ABOUT COREY

- Early Life & Education – Born in Crosby ND, Worked on farm until HS graduation, College at UND-Accounting Degree (Go Sioux!!)
- Career
    - Weber Spaulding (Minot) – Public Accounting
    - ANG Coal Gasification(Bismarck) – Listed Consortium
    - Gold Seal Company (Bismarck)– Private Company
    - Charles Bailly (Bismarck) – Public Accounting
    - Bobcat Company (Bismarck) – Listed Company (7 years)
    - CNH Industrial (Fargo) – Listed Company (17 years) CNH stands for Case – New Holland
    - Retired 2013

A LITTLE MORE ABOUT COREY

- Land owner in Divide County, North Dakota (land was homesteaded by my ancestors)
- Mineral Owner in Divide County, North Dakota
  - Have mineral ownership that is held under a lease which pays royalties.
  - Have mineral ownership that is producing under the terms of an unleased mineral interest pursuant to NDCC 38-08-08

TOPIC ONE – LEASED MINERAL INTERESTS

- Lease is for mineral ownership that covers three contiguous 1280 acre spacing units.
- Lease was negotiated for the benefit of parties that controlled > 50% of each spacing unit.
- Lease contains specific language that prohibits the operator from making any deductions whatsoever from the royalty payment.

North Dakota Board of University and School Lands: Minerals Policy Manual, Page 13

4. Lessee agrees that all royalties accruing to lessor under this policy shall be without deduction for the cost of producing, gathering, storing, separating, treating, dehydrating, vapor recovery, compressing, processing, transporting, conditioning, removing impurities, depreciation, risk capital, and otherwise making the oil, gas and other products produced hereunder ready for sale or use.

TOPIC TWO – UNLEASED MINERAL INTERESTS

- Similarities to Topic One
  - Mineral interests are contiguous to the three spacing units in topic one.
- Dissimilarities to Topic One
  - Mineral owners were unable to negotiate as a group that controlled >50% of the spacing unit.
  - Operator made several offers to lease which were determined by the remaining mineral owners' to be unacceptable offers and were rejected. In late August 2021 I met with a representative of the Operator in Bismarck and expressed our frustration with their tactics and their unwillingness to negotiate in good faith. (Note: During my tenure as Controller for Bobcat and CNH Industrial I was at the negotiating table for 4 Union Contracts, believe me I know what negotiating in good faith vs bad faith is).
  - At that meeting I was instructed by the Operator's representative to sign the lease they offered as it was their last and final offer.

AND NOW THE FUN STARTS

BIG BULLY OIL. LLC

P.O. Box 935
Bismarck, ND 58502-0935
Phone: (701) 255-5662 FAX: (701) 258-1562
Email: [redacted].com

[redacted]

Less than 10 days later

September 8, 2021

CORRECTED

RE: Well Proposal

[redacted]
T162N-R100W
Sec. 04 & 09: ALL Divide Co., ND

Dear Owner:

[redacted] hereby proposes to drill the [redacted] as Three Forks formation horizontal well with a spacing unit described as Section 04: All and Section 09: All, Township 162 North- Range 100 West, Divide Co., ND. The surface location of the well will be 425' FSL, 1,450' FWL of Section: 33, Township 163 North, Range 100 West. The bottom hole location will be 50' FSL, 1,600' FWL of Section: 09, Township 162 North, Range 100 West with a total horizontal offset length of 11,000'. This well has been drilled but not completed with completions planned sometime this month.

[redacted] would prefer to secure a lease on your minerals but in the alternative, you can elect to participate in the operation and pay your share of the drilling costs. After multiple unsuccessful lease negotiation attempts, our final lease offer to you is **[redacted]/acre for a [redacted]-year lease with a [redacted] royalty on an approved Big Bully Oil, LLC [redacted] lease form**.

According to the title information available, you own an unleased mineral interest of [redacted] net acres or a [redacted] working interest the proposed 1,280.16 spacing unit. [redacted] invites your participation in this well. The Title Opinion is being worked on for this well and your final working interest percentage and any resulting accounting change to your billings will be based on the opinion. As such, you should verify your interest in the proposed spacing unit prior to making your election as your election will be based on your full actual working interest in the spacing unit. Enclosed is a cost estimate (AFE) for the drilling ($2,222,000) and completion ($3,859,533) of this well; totaling $6,081,533 gross. If you elect to participate, please provide this office with a signed AFE and payment for your estimated share of the AFE drilling and completion costs ($950,239.53) based on our title information.

[redacted] would like to have your response as soon as possible, but at least within 30 days from receipt of this notice. Should you fail to make an election during that period, your interest may be subject to penalties under Joint Operating Agreement or force pooled under the applicable statutes of the state of North Dakota. In the event, your working interest will be subject to a risk

penalty as allowed by Section 38-08-08 of the North Dakota Century Code, as promulgated by the North Dakota Industrial Commission (NDIC). If you object to the risk penalty, then you have the right to respond in opposition to any petition for a risk penalty tha[redacted] could file with the NDIC regarding this well. In the event no risk penalty petition is filed, you may file a petition with NDIC requesting a hearing on this matter.

Please indicate your participation election in the space below and return one executed copy of this letter to my attention at the address shown above. If your decision is to participate, return a signed copy of the AFE as well

If you elect to participate, please provide a check in the amount of **$950,239.53** to the following:

[redacted]
Department #41404
P.O. Box 650823
[redacted]

EMAIL DATED APRIL 21, 2022

We have had a chance to review the first Royalty payments made by [redacted] on the below referenced well. We have several questions and I was wondering if you could take some time to address them. I am available to clarify the questions if you need further information or perspective. Feel free to call me at 701-306-3986.

Regards,
Corey

Questions regarding the Royalty Payments on UMI for [redacted]
Volumes Royalty Paid On:
Below is the information [redacted] provided the State of ND. The Oil volumes seem to agree with the volumes on the Royalty Statement. The Casinghead Gas volumes do not seem to agree. The volumes paid on were significantly below the volumes produced. The understanding is that [redacted] owes the mineral owner a royalty on all gas produced. Please explain the discrepancy in gas produced vs gas paid on Royalty Statement.

Oil price used to determine royalty payment:
It appears that [redacted] is using a "Price after Deductions" to base the royalty calculation on. The understanding is that [redacted] should be using the "Gross Price Received" as the statutes call for a cost free royalty to be paid to the mineral owner. Please explain the term "Price after Deductions" and detail the deductions that are being taken to determine this value.
Casinghead Gas price same questions as Oil above.
Casinghead Gas Processing Fees:
Deductions were taken at a straight 25% for "Processing Fees". The statute calls for a cost free royalty to be paid to the mineral owner. What methodology is [redacted] using to make a 25% deduction from a price that already included deductions before calculating the royalty payment? Please explain in detail the calculation of the Casinghead Gas royalty.
Products:
Same situation and questions as the Casinghead gas category.

EMAIL DATED MAY 11, 2022

Can you provide a time line of when [redacted] will respond to the questions that were raised on the above referenced well?

Regards,
Corey

EMAIL DATED MAY 11,2022

Good Afternoon, Mr. Dahl,

I will address part of your email, but the explanation of the deductions and payout statements are not my department. I will discuss the statutory royalty and "cost-free" issue below:

Under North Dakota law, unless an oil and gas lease has a specific provision restricting certain costs from being deducted from royalty payments on production, an operator may deduct certain costs associated with marketing, processing, transportation, etc. This has been established numerous times in the ND courts including the case Petro-Hunt v. Bice. [redacted] deductions on royalty payments are within the boundaries of the law.

Also under ND law, statute doesn't provide a "cost-free royalty" in the sense of gross proceeds at the wellhead. However, your statutory royalty of 16% (or average weighted royalty in the unit per operator's choice) does not bear the costs to drill, complete, or operate the well; the 84% [redacted] receives does. As a non-consent unleased mineral owner, you are not responsible for the costs associated with drilling and completion the well until the well pays out 150% of those costs to drill/complete. During this non-consent penalty period, [redacted] carries the liabilities and costs to operate while receiving an operational cost bearing 84% royalty to cover the non-consent costs your whole interest bears. Also under the law, the operator has certain lien rights if costs are not paid by partners in the well, which provides the operator a royalty percentage of non-consent unleased owners to recoup those costs.

[redacted] deducts what is allowed under law and you are paid a royalty on the same basis as [redacted] post deductions. You are being treated as any other non-consent mineral owner under the force pool statutes of North Dakota. Should you have any other issues regarding deductions, you should reach out to your attorney for advice. [redacted] is deducting what is allowable under the law and will continue to do such.

Kevin will have to address the more specific deductions and payout information. However, I can tell you that the state's website is not always up to date. Also, produced vs. sold comes into play. Just because it was produced, doesn't mean we sold the product yet. That's where there could be some discrepancy on volumes v sold.

Thank you,

[redacted], Esq
Professional Landman

Type		Production Date	Property Values			
			BTU	Volume	Price	Value
Property:	**118*23513**	**ORLYNNE 2-3H, State: ND, County: DIVIDE**				
CASINGHEAD GAS						
	ROYALTY INTEREST	Nov 22		464.59	4.52	2,101.05
	Price After Deductions: 3.39; Property Value Less Deductions: 1575.79; [redacted] Original					
	SEVERANCE TAX	Nov 22				(83.52)
OIL SALES						
	ROYALTY INTEREST	Dec 22		356.76	79.47	28,351.04
	Price After Deductions: 77.35; Property Value Less Deductions: 27593.88 [redacted] Origi					
	SEVERANCE TAX	Dec 22				(1,379.69)
	ROYALTY INTEREST	Dec 22		356.76	79.47	28,351.05
	Price After Deductions: 77.35; Property Value Less Deductions: 27593.89; [redacted] Origi					
	SEVERANCE TAX	Dec 22				(1,379.69)
PRODUCTS						
	ROYALTY INTEREST	Nov 22		8,154.28	0.59	4,802.46
	Price After Deductions: 0.12; Property Value Less Deductions: 948.61; [redacted] Original					

Interesting math: Severance tax on Casinghead gas is 3.397515% which is a number found nowhere in ND Statute. Per NDCC 57-51-02.2 the Production Tax should be .0905 cents per MCF. Thus 464.59 * .0905 = $42.04 Royalty is paid on Gross Value. Severance Tax is paid on Net Value. (356.76 * 79.47 = 28,351.04) (28351.04 * 5% = 1,417.52) (356.76 * 77.35 = 27,595.54) (27,595.54 * 5% = 1379.69)

CASINGHEAD GAS							
	UNLEASED MINERAL INTEREST	Nov 22		2,061.10	4.52	9,321.09	0.0
	Price After Deductions: 3.39; Property Value Less Deductions: 6990.22; [redacted] *Original sale*						
	SEVERANCE TAX	Nov 22				(516.18)	0.0
	PROCESSING FEE	Nov 22				(2,330.87)	0.0
	Transaction Code Interest Type Summary Code: Processing						
OIL SALES							

Amount is exactly 25% of Revenue

			Property Values			
	Type	**Production Date**	**BTU**	**Volume**	**Price**	**Value**
	UNLEASED MINERAL INTEREST	Dec 22		6,174.69	77.41	477,971.03
	Price After Deductions: 77.41; Property Value Less Deductions: 477971.03; [redacted] *Origin*					
	SEVERANCE TAX	Dec 22				(23,898.55)
	EXTRACTION TAX	Dec 22				(23,898.55)
PRODUCTS						
	UNLEASED MINERAL INTEREST	Nov 22		42,978.78	0.63	27,205.22
	Price After Deductions: 0.18; Property Value Less Deductions: 7877.34; [redacted] *Original sale*					
	PROCESSING FEE	Nov 22				(19,327.88)
	Transaction Code Interest Type Summary Code: Processing					

Amount is 71% of Revenue

More Interesting math: Severance tax on Casinghead gas is 5.53776% which is a number found nowhere in ND Statute. Per NDCC 57-51-02.2 the Production Tax should be .0905 cents per MCF. Thus 2061.1 * .0905 = $186.52.

DETAIL PAYOUT STATEMENT
Period End Date
As of 12/31/2021

Date Range
12/31/2021 - 12/31/2021

Owner Number:
Payout Master ID: [redacted] 150%

Description	Volume Current Month/Range	Current Month/Range	Inception to Date	Fctr/ Penlt%	Payout Amount
REVENUE					
OIL	30,053.19	2,220,521.19	2,220,521.19		
LESS: TAXES & DEDUCT		222,052.12	222,052.12		
LESS: ROYALTY/ORRI	5,509.75	366,386.01	366,386.01		
WORK INT OIL	24,543.44	1,632,083.06	1,632,083.06	100	1,632,083.06
PRICE	73.89				
CASINGHEAD GAS	4,654.91	26,270.82	26,270.82		
LESS: TAXES & DEDUCT		7,143.95	7,143.95		
LESS: ROYALTY/ORRI	853.40	3,506.59	3,506.59		
WORK INT CASINGHEAD GAS	3,801.51	15,620.28	15,620.28	100	15,620.28
PRICE	5.64				
PRODUCTS	96,285.93	85,165.54	85,165.54		
LESS: TAXES & DEDUCT		48,765.72	48,765.72		
LESS: ROYALTY/ORRI	17,652.42	6,673.30	6,673.30		
WORK INT PRODUCTS	78,633.51	29,726.52	29,726.52		29,726.52
PRICE	0.88				
TOTAL REVENUE		1,677,429.86	1,677,429.86		1,677,429.86

TOTAL REVENUE		1,677,429.86	1,677,429.86		1,677,429.86
EXPENSE					
PROD LEASE WIP - IDC					
PROD LEASE WIP - IDC		17,858.50	1,786,341.53	150	2,679,512.30
TOTAL 807		17,858.50	1,786,341.53		2,679,512.30

Payout Master ID: [redacted] 150%

Description	Volume Current Month/Range	Current Month/Range	Inception to Date	Fctr/ Penlt%	Payout Amount
INTANGIBLE COMPLETION COST					
INTANGIBLE COMPLETION COST		61,872.89	2,794,242.14	150	4,191,363.21
TOTAL 808		61,872.89	2,794,242.14		4,191,363.21
DRILLING EQUIPMENT - ACP - TCC					
DRILLING EQUIPMENT - ACP -		42,094.72	1,074,643.55	150	1,611,965.33
TOTAL 810		42,094.72	1,074,643.55		1,611,965.33
DRILLING EQUIPMENT - BCP - TDC					
DRILLING EQUIPMENT - BCP -			493,328.05	150	739,992.08
TOTAL 809		0.00	493,328.05		739,992.08
LEASE OPERATING EXPENSE - LOE					
LEASE OPERATING EXPENSE - L		114,812.47	121,036.26	100	121,036.26
TOTAL 905		114,812.47	121,036.26		121,036.26
GEN LIABILITY INSURANCE					
GEN LIABILITY INSURANCE		59.65	178.95	100	178.95
TOTAL GLI		59.65	178.95		178.95
OEE INSURANCE					
OEE INSURANCE		10.39	31.17	100	31.17
TOTAL INS		10.39	31.17		31.17
OVERHEAD - COMBINED FIXED RATE					

Owner Number:
Payout Master ID: [redacted] 150%

Description	Volume Current Month/Range	Current Month/Range	Inception to Date	Fctr/ Penlt%	Payout Amount
OVERHEAD - COMBINED FIXED R		1,403.38	4,210.14	100	4,210.14
TOTAL OH		1,403.38	4,210.14		4,210.14
WORKOVER EXPENSE - WIP					
WORKOVER EXPENSE - WIP		570.25	7,262.61	150	10,893.92
TOTAL 938		570.25	7,262.61		10,893.92
TOTAL EXPENSE		238,682.25	6,281,274.40		9,359,183.36
Payout Balance					-7,681,753.50

Please Direct Inquires
Concerning this Statement to:

[redacted]

Address is a PO box in TX

EMAIL DATED MAY 17, 2022

Mr. Dahl,

Please see attached payout statement for the well's 100% payout and 150% non-consent penalty period. As of this statement, the remaining balance for 150% payout is over $7.6 million dollars. This will take some time to recoup but feel free check back in a year for an update on payout.

Sincerely,

[redacted], Esq

Professional Landman

EMAIL DATED AUGUST 25, 2022

Gentlemen,

It has been awhile since I sent my first inquiries to you and I must say I was not overwhelmed by your response. I was expecting a little more of a professional response from [redacted], but on the other hand given our history the response seemed fitting. I was looking for a detailed payout statement for only my share of the drilling costs which is obviously not in the 7.6 million range. Thus I have been forced to "run the numbers" on my own based on the partial deck that I am privy to . Please see attached the results of my assessment of the well data through the month of June for oil and May for the casinghead gas and products. In a nutshell the data would indicate that the well has reached payout for [redacted] and that my share of the drilling of the well has a couple of months left at the current rate of production. This would seem to be a far cry from the "check back in a year for an update". Thus we seem to once again have a disconnect that may or may not blossom into a trust issue depending on [redacted] reply to this inquiry. I know that [redacted] keeps meticulous records on all aspects of the operation of each well. Therefore it should be no great burden for you to share that information with me as a participant in this endeavor.

With respect to the issues surrounding the deductions from our royalty portion of the well's operations I will defer them to a later date as to not overburden [redacted], but do not consider them dropped. I will point out that your reference to PHLLC vs Bice does not convince me, as it is clearly a lease term dispute. As you will recall we do not have a lease between us and I have already stated [redacted] does not have the power to unilaterally establish the terms by which we will do business. I would prefer to establish those terms in a businesslike manner as opposed to letting a bunch of attorneys go back and forth trying to figure out what the legislature intended. If you feel so inclined feel free to reach out to me to discuss the options that we may have to resolve these differences of opinion.

Regards,

ACCOUNT	AFE	ACTUAL	DIFFERENCE	TOTAL UMI
				0.15625
118.807	1,859,700.00	1,786,341.53	(73,358.47)	418,673.80
118.808	2,677,362.00	2,794,242.14	116,880.14	654,900.50
118.809	362,300.00	493,328.04	131,028.04	115,623.76
118.810	1,182,171.00	1,074,643.55	(107,527.45)	251,869.58
	6,081,533.00	6,148,555.26	67,022.26	1,441,067.64
	950,239.53			490,828.11
118.905		121,036.26		18,911.92
GLI		178.95		27.96
INS		31.18		7.31
OH		4,210.14		657.83
118.938		7,262.61		1,702.17
		132,719.14		21,307.19
TOTAL		6,281,274.40		1,462,374.83

Cost represents 23% of the cost to drill

TOTAL PRODUCTION $	OIL	$10,852,325.01
	GAS	164,200.81
	PRODUCTS	477,792.73
		$11,494,318.55
Royalty Simple math (11,494,318.55 * .15625 * 16% = 287,357.93)		
Actual Royalty		258,190.60

13 months of production – 122491 bls of oil sold at an average price of $89.33. Yet the well has not "paid out".

Life to date of well-Owners of the mineral rights under 15.625% of the spacing unit have received a little over 2% of the total proceeds.

SB 2374 HEARING

TESTIMONY PROVIDED BY COREY J DAHL

HOUSE BILL 1203 APPROVED APRIL 14, 1983

House Bill No. 1203

Before the Senate Natural Resources Committee

Testimony of
Douglas L. Johnson
Assistant Attorney General
Oil and Gas Division
North Dakota Industrial Commission

TO: North Dakota Gas Producers and Purchasers

FROM: North Dakota Office of State Tax Commissioner

SUBJECT: Notification of Gas Tax Rate for Fiscal Year 2023

DATE: June 1, 2022

In keeping with the provisions of North Dakota Century Code (N.D.C.C.) § 57-51-02.2, the Tax Commissioner has determined that the gas tax rate for the fiscal year beginning July 1, 2022, through June 30, 2023 is $.0905 per mcf. The gross production tax on gas produced during this time period must be calculated by taking the taxable production in mcf times the $.0905 tax rate.

House Bill No. 1203 amends Subsection 1 of Section 38-08-08 of the North Dakota Century Code to provide that when the Industrial Commission force pools a spacing unit unleased mineral owners are to be treated as royalty owners as to 1/8 of their interest and are to be treated as working interest owners as to the other 7/8 of their interest. As everyone may not understand the terms "spacing" and "pooling" I will briefly explain the terms…….

The problem that House Bill 1203 addresses is what happens to an unleased mineral owner when a spacing unit is force pooled…….

Putting this into actual dollar figures, assume that the well drilled by Gulf cost $2 million to drill and complete and produced 60,000 barrels of oil before being plugged. Assume that the oil sold for an average of $30 per barrel for a total revenue of $1.8 million. In other words the well does not pay out.

Under the Industrial Commission's order, the money from the sale of the oil would have been divided as follows:

N/2 of the Section

Mr. Smith — 1/8 x 1/2 x $1,800,000 = $112,500

Gulf----------- 7/8 x 1/2 x $1,800,000 = $787,500

y

S/2 of the Section

Mrs. Black — 1/8 x 1/2 x $1,800,000 = $112,500

Gulf---------- 7/8 x 1/2 x $1,800,000 = $787,500

$1,800,000

If Mrs. Black's unleased minerals are treated entirely as a working interest,
as some oil companies want, the proceeds from the 60,000 barrels of oil would be divided as follows:

N/2 of the Section

Mr. Smith — 1/8 x 1/2 x $1,800,000 = $112,500

Gulf............. 7/8 x 1/2 x $1,800,000 = $787,500

S/2 of the Section

Mrs. Black -- 0

Gulf .... 8/8 x 1/2 x $1,800,000 = $900,000

$1,800,000

The Industrial Commission has felt that It is "just and reasonable" to include a 1/8 - 7/8 provision in its pooling orders because such a provision is necessary to ensure that all mineral interest owners received their ‘just and equitable share" of production. The Industrial Commission does not feel that it is ever just and equitable for a mineral owner to receive nothing from a well that produces close to $2 million worth of oil when the mineral owner owns half the minerals under the well.

North Dakota Board of University and School Lands: Minerals Policy Manual, Page 11

Royalties. If a sale of gas, carbon black, sulfur, or any other products produced or manufactured from gas produced and marketed from the leased premises, including liquid hydrocarbons recovered from such gas processed in a plant, does not constitute an arm's length transaction, the royalties due lessor shall be as follows:

1. On any gas produced and marketed (except as provided herein with respect to gas processed in a plant for the extraction of gasoline, liquid hydrocarbons or other products), the royalty, as determined by the Board, shall be based on the gross production or the market value thereof, at the option of the lessor, such value to be based on the highest market price paid for gas of comparable quality and quantity under comparable conditions of sale for the area where produced and when run, or the gross proceeds of sale, whichever is greater; provided that the maximum pressure base in measuring the gas under this lease contract shall not at any time exceed 14.73 pounds per square inch absolute, and the standard base temperature shall be sixty (60) degrees Fahrenheit, correction to be made for pressure according to Boyle's Law, and for specific gravity according to a test made by the Balance Method or by the most approved method of testing being used by the industry at the time of testing.

2. On any gas processed in a gasoline plant or other plant for the recovery of gasoline or other liquid hydrocarbons, the royalty, as determined by the Board, is based on the residue gas and the liquid hydrocarbons extracted or the market value thereof, at the option of the lessor. All royalties due herein shall be based on eighty percent or that percent accruing to lessee, whichever is greater, of the total plant production of residue gas attributable to gas produced from the leased premises, and on forty percent or that percent accruing to lessee, whichever is greater, of the

total plant production of liquid hydrocarbons attributable to the gas produced from the leased premises; provided that if a third party or parties are processing gas through the same plant pursuant to arm's length transaction and one such transaction accounts for an annual average of ten percent or more, or all such transactions collectively account for an annual average of thirty percent or more of the gas being processed in such plant, the royalty shall be based on the gross proceeds of sale that would accrue to lessee if the gas were processed under the terms of the most remunerative third party transaction for processing gas in such plant. Respective royalties on residue gas and on liquid hydrocarbons where the requirements for using third party transactions cannot be met shall be determined by

a. The highest market price paid for any gas (or liquid hydrocarbons) of comparable quality and quantity under comparable conditions of sale in the general area F.O.B. at the plant after processing;

b. The gross proceeds of sale for such residue gas (or the weighted average gross proceeds of sale for the respective grades of liquid hydrocarbons), F.O.B. at the plant after processing; or

c. The gross proceeds of sale paid to a third party processing gas through the plant, whichever is greater. Lessee shall furnish copies of any and all third party gas processing agreements pertaining to the plant upon lessor's request.