UNITED STATES BANKRUPTCY COURT
FOR THE WESTERN DISTRICT OF MICHIGAN

In re:

AURORA OIL & GAS CORPORATION,

Debtor.
_______________________________________/

Case No. DT 09-08254
Chapter 11
Hon. Scott W. Dales

FRONTIER ENERGY, LLC,

Plaintiff,

v.

AURORA ENERGY, LTD,

Defendant.
_______________________________________/

Consolidated Adversary Pro. No. 09-80518
LEAD CASE

OPINION AND ORDER AFTER TRIAL

PRESENT: HONORABLE SCOTT W. DALES
United States Bankruptcy Judge

For several days from December 2010 to June 2011, the court conducted a trial during which it heard from numerous witnesses and admitted thousands of pages of exhibits regarding a natural gas royalty dispute between Frontier Energy, LLC ("Frontier" or "Plaintiff") and Aurora Energy, Ltd. ("Aurora"). At the close of the Plaintiff's proofs, and upon Aurora's Motion for Judgment on Partial Findings, the court dismissed several of Frontier's claims, leaving only the issue of whether Aurora breached an oil and gas lease (the "Hudson Agreement") by making unwarranted deductions from Frontier's royalty checks and miscalculating "Payout" -- a negotiated and unique term dramatically affecting Frontier's royalty rate.

I. JURISDICTION AND FORM OF RULING

The United States District Court has jurisdiction over Aurora's Chapter 11 bankruptcy case pursuant to 28 U.S.C. § 1334, but has referred the case and related proceedings to the United States Bankruptcy Court pursuant to 28 U.S.C. § 157(a) and LCivR 83.2 (W.D. Mich.). This adversary proceeding is a core proceeding pursuant to 28 U.S.C. § 157(b)(2)(A), (B) and (O) (administration of the estate; allowance and estimation of claims; and adjustment of the debtor-creditor relationship).

As the parties anticipated, this Opinion leaves certain issues unresolved and the court is therefore unable to enter a final judgment at this time. *See* FED. R. CIV. P. 54. Nevertheless, this Opinion constitutes the court's findings of fact and conclusions of law in accordance with FED. R. CIV. P. 52, made applicable to this adversary proceeding by FED. R. CIV. P. 7052.

II. PROCEDURAL HISTORY

This adversary proceeding arises out of, or is otherwise related to, a lawsuit that Frontier filed against Aurora in Michigan's Charlevoix County Circuit Court (the "State Court Action"). The State Court Action, which predated Aurora's Chapter 11 bankruptcy petition, was initially a dispute about royalty payments under two oil and gas contracts between the parties referred to as the Hudson Agreement and the Corwith Agreement.

On July 12, 2009, while the State Court Action was pending, Aurora filed a voluntary petition for relief under Chapter 11 automatically staying the State Court Action. In its bankruptcy case, Aurora objected to the amount of Frontier's claim related to the Agreements (DN 432) and filed a motion to estimate (DN 482) in connection with Aurora's plan confirmation. Shortly before the confirmation hearing, Aurora removed the State Court Action to the bankruptcy court under 28 U.S.C. § 1452, commencing the above-captioned adversary proceeding on November 12, 2009.

The parties agreed that their dispute should not delay the progress of the bankruptcy base case and were willing to resolve their differences after plan confirmation, which occurred on December 11, 2009. On April 28, 2009, Aurora filed the first in a series of motions for summary judgment (DN 73) asserting that there was no genuine issue of material fact regarding the Corwith Agreement. Frontier opposed the motion (DN 94). The court heard argument on June 2, 2010 and denied the motion in an order dated June 4, 2010 (DN 147).

On the same day the court denied Aurora's motion for partial summary judgment, Frontier filed two of its own motions (DN 118 and 124). The first motion asserted that Aurora had miscalculated Payout on the contracts and had also taken improper deductions from Frontier's royalties. Aurora opposed this motion (DN 181) stating that there were genuine issues of material fact regarding, among other things, contract interpretation, course of performance, and, more generally, the intention of the parties. Frontier's second motion for summary judgment asked for a determination that the oil and gas leases were unexpired leases or executory contracts and subject to assumption or rejection pursuant to 11 U.S.C. § 365. Aurora also opposed this motion (DN 182) contending that under Michigan law, an oil and gas lease conveys an ownership interest in the sub-surface minerals, and therefore does not qualify as a true lease within the scope of 11 U.S.C. § 365. In addition, Aurora argued that performance was not due from both parties, so the contracts were not "executory."

At the hearing to consider these issues on July 28, 2010, the court issued a bench ruling on the Plaintiff's motion for summary judgment involving the miscalculated Payout and improper deductions from royalties, finding that there were genuine issues of material fact that required a trial (DN 186). The court took the motion regarding the Section 365 issues under advisement. On August 13, 2010, the court issued an opinion and order determining that the contracts were in fact unexpired leases within the scope of Section 365 which Aurora, as the debtor, could assume or reject after the adversary proceeding was concluded (DN 188). Aurora filed a reconsideration motion (DN 191) which the court denied (DN 198).

On November 16, 2010, both parties filed motions *in limine* (DN 215 and 217) in an effort to exclude certain witnesses from testifying at trial. Before the hearing on these motions, Frontier withdrew the objectionable witness from its list, thereby rendering Aurora's motion moot. With respect to Frontier's motion, the court excluded some of Aurora's proposed witnesses from testifying (DN 232).

Trial commenced on December 9, 2010. On December 14, 2010, after several days of testimony, Frontier rested its case, except that the parties agreed to permit Kathie Piper to submit her testimony by declaration to accommodate her personal issues. Frontier filed Ms. Piper's declaration on February 2, 2011 (DN 248).

Aurora then moved for judgment on partial findings (DN 249) regarding Frontier's claims that Aurora: (1) breached a fiduciary duty owed Frontier; (2) breached its duty to act as a reasonably prudent operator; (3) underpaid royalties to Frontier as to the Corwith Agreement; and (4) breached the Hudson Agreement by improperly deducting charges for compression from Frontier's royalty. On March 2, 2011, the court granted the motion as to the fiduciary duty claim, the prudent operator claim, and the underpaid royalties regarding the Corwith Agreement, having concluded that Frontier did not meet its burden of proof with respect to these claims. The court denied without prejudice the motion on the compression claims regarding the Hudson Agreement (DN 261).

After some unsuccessful settlement negotiations between the parties, trial resumed on March 7, 2011, and continued on March 10, May 12, May 13, May 19, May 20, and June 6, 2011. The parties agreed to submit their closing arguments in writing no later than July 20, 2011, but later agreed to extend this deadline to July 22, 2011 (DN 276). Both parties submitted their closing arguments on that date (DN 278 and 279). Finally, the parties filed a joint stipulation (DN 281) agreeing that this court may enter final judgment under 28 U.S.C. § 157 despite the recent Supreme Court decision in *Stern v. Marshall*, 131 S. Ct. 2594 (2011).

III. FACTUAL BACKGROUND

Both parties contend they are sophisticated players in the oil and gas industry. Frontier's principals -- members of the Nielson family -- formerly owned North Michigan Land and Oil Company, an entity that controlled about 15% of the Antrim wells in Northern Michigan.[1] In 1997, the Nielsons decided to get out of the business of operating wells, and sold the assets of North Michigan Land and Oil to GE Capital, but retained the company's mineral rights by transferring them to Frontier. At about the same time, they formed Generations Management, LLC to manage those mineral rights (along with other Nielson family holdings). For its part, Aurora was a publicly-traded company with wide-ranging lease agreements throughout Michigan and elsewhere. Like Frontier, Aurora has a long history of activity in the oil and gas business.

In early 2001, Aurora contacted Frontier about leasing a large mineral estate in Charlevoix County. Trial Tr. Dec. 9, 2010, 35:19-36:3. Aurora normally used a form lease provided by the State of Michigan to document its agreements with lessors. Because Frontier wanted to modify some terms prescribed in the form, however, the parties entered into six or seven months of negotiations and propounded several proposed drafts before they agreed to a

[1] The Antrim Shale is a well-established, relatively shallow petroleum-producing underground formation in Michigan.

tiered royalty scheme in which royalties would increase with the price of natural gas after a negotiated point in time. Trial Tr. Dec. 9, 2010, 148:12-19; PX-1. To memorialize the agreement, the parties used the State of Michigan form lease but revised it to include a provision affecting the royalty rate, with one rate applying "before Payout" and another applying "after Payout." The parties then proceeded to draft a non-standard definition for the non-standard concept of "Payout," the interpretation of which now lies at the heart of this dispute. *See* PX-1 at p. 11, ¶ 5. The lease also limits the deductions Aurora can take from Frontier's royalty by enumerating three categories of deductions: CO_2 removal, third party transportation, and necessary compression.

The parties executed the final version of the Hudson Agreement on January 25, 2002. In October 2002, O.I.L. Energy Corporation ("OIL") and Aurora formed an area of mutual interest by combining lands leased by OIL with lands leased by Aurora, and subdividing them into six separate units -- Hudson 34, Hudson SW, Hudson NE, Hudson NW, Hudson 19 and Hudson 13 (the "Hudson Units"). Trial Tr. March 7, 2011, 185:12-186:1; PX-53 at pp.5-6. Aurora and OIL each operated three units.

Before producing gas for sale, Aurora and OIL had to complete several preliminary activities, including: geological assessments (Trial Tr. March 7, 2011, 39:16-40:4); lease acquisitions (*id.* 40:10-19); title confirmations (*id.* 40:23-41:2); location selection (*id.* 41:19-42:5); permit application and approval (*id.* 47:22-48:10); well-site preparation (*id.* 48:15-21); spudding the wells (*id.* 60:8-61:22); and production of division order title opinions (*id.* 180:18-181:16).[2]

[2] Testimony showed that even though the Antrim Shale is well-established, drilling for natural gas is a complex, interdisciplinary undertaking, even when everyone knows generally where to drill.

Also in 2004, OIL and Aurora decided to form a midstream company, Hudson Pipeline and Processing Company ("HPPC"), to share capital and operating costs, such as gas treatment and transportation. Trial Tr. March 7, 2011, 120:2-19. OIL and Aurora hired Major Pipeline, LLC ("Major Pipeline") to oversee the construction and operation of the infrastructure associated with HPPC, including building, operating and/or obtaining the compressors, transportation lines, and other processing equipment, as well as the necessary regulatory approvals for the construction and operation of the pipelines. PX-63; Trial Tr. March 7, 2011, 127:7-17. Consequently, the Aspen pipeline was completed and approved on November 9, 2004; the Birch pipeline on January 25, 2005; and the Chestnut, Dogwood and Elm pipelines on December 12, 2006. PX-63, PX-64, PX-65, PX-66 and PX-67.

After the Michigan Public Service Commission approved the pipelines, HPPC was required to transport all of OIL's and Aurora's gas, as well as gas for others. *See* M.C.L. § 483.104 ("Every corporation . . . claiming or exercising the right to carry or transport natural gas by pipe line or lines, for hire, compensation, or otherwise, within the limits of this state . . . shall be a common purchaser thereof, and shall purchase all the natural gas in the vicinity of, or which may be reasonably reached by its pipe lines, or gathering branches, without discrimination in favor of 1 producer or 1 person as against another . . .").

HPPC also constructed central production facilities in each of the Hudson Units. Trial Tr. March 7, 2011, 61:14-62:5. Each facility housed "screw" or "booster" compressors which Aurora used to compress gas through the first of four stages of compression in order to increase pressure to the point that gas would move through the pipelines for processing and eventually to sale. A booster compressor also regulates back pressure at the wells, which tends to enhance production. *Id.*, 76:4-10. The other three compressors, all built by HPPC, were installed at the

Hudson 34 unit, along with dehydration towers and hydrogen sulfide removal towers. *Id.*, 79:5-20.

Although the parties signed the Hudson Agreement in 2002, wells on the Hudson Units did not begin producing until 2004, presumably because Aurora and OIL needed to complete the initial infrastructure to make production possible. From the time production started, gas began pumping from the wells and entering the compression process at Hudson 34. In general, gas covered by the Hudson Agreement typically runs through the dehydration and sulfide removal towers at Hudson 34, after which it travels from that facility and into the Aspen pipeline, and then into the North Elmira pipeline which is operated by an entity known as "Atlas." Trial Tr. March 7, 2011, 81:9-12. Once through the North Elmira pipeline, the gas flows into the Terra Hayes pipeline which is operated by DCP Midstream Partners. *Id.* After the gas leaves the Terra Hayes pipeline, it is stripped of carbon dioxide (or "CO_2") at the Warner CO_2 Treating Plant (Trial Tr. March 7, 2011, 81:19-82:3) operated by DTE Michigan Holding, Inc. ("DTE"). PX-53. Thereafter, the gas travels through the Jordan Valley pipeline and the Michigan Consolidated Petoskey pipeline to the point of sale. Trial Tr. March 7, 2011, 82:4-16.

In late November or early December 2006, after a dispute arose between Aurora and Major Pipeline regarding a shutdown at the Warner Plant, Aurora terminated Major Pipeline as HPPC's manager and assumed that role itself. Trial Tr. March 7, 2011, 131:5-17. Also in 2006, Aurora purchased OIL's interests in the Hudson Units and operated those, too. Aurora's ownership interest in HPPC, when HPPC was initially formed, was 48.5%. (Joint Pretrial Order, November 2, 2010, DN 210). From August 18, 2007 to March 1, 2009, Aurora's ownership interest in HPPC grew to 93.6% where it remained until March 1, 2009 when it rose to 96.1%. On December 11, 2009, Aurora became the sole owner of HPPC. *Id.*

Throughout this time, Aurora was largely mindful of the corporate lines between it and HPPC, although its books misallocated certain assets to Aurora and similar accounting problems persisted. Recognizing some of these difficulties, Aurora hired Russ Lawson to find solutions to the accounting issues and to prepare a business plan for HPPC. During his investigation, Mr. Lawson determined that HPPC was charging certain post-production costs ("PPCs") at the wrong rate, or not at all. Trial Tr. March 7, 2011, 145:10-25. After calculating the proper PPCs, Mr. Lawson worked with HPPC's accounting office to charge the royalty holders the appropriate amounts, using his business plan as a guide. *Id.* 147:11-148:2.

In the meantime at Frontier, Dale and David Nielson (the "Nielson Brothers"), then the officers at Generations Management, were in the process of handing the business over to Dale's daughter, Cori, and his son, Keith, as co-chief operating officers. Generations Management's sole purpose is to keep track of the Nielson Family assets including Frontier's oil and gas leases, by auditing and monitoring lease performance, and verifying and collecting royalties. Therefore, presumably just about everyone employed by Generations Management is involved in conducting some aspect of the audits and review of the royalties Frontier receives. Certainly, those in charge of Generations Management were also involved with comparing those royalty payments with Frontier's contractual rights. Trial Tr. May 13, 2011, 111:23-112:118.

In 2003, while the Nielson Brothers were still in charge, they hired Kathie Piper as a Project Leader. Trial Tr. May 13, 2011, 74:24-75:5. For over 20 years, Ms. Piper worked in the oil and gas development industry, specifically with respect to the Antrim Shale. *Id.* 77:6-18. She held the position of Project Leader until January 1, 2009, when she became the Vice President of Oil and Gas Development and Private Equity Acquisitions. *Id.* 74:15-17. Given this experience, the court fairly characterizes her as an industry veteran.

While she was a Project Leader, Ms. Piper was in charge of auditing Aurora's Payout statements in order to determine when Payout had been reached. Trial Tr. May 13, 2011, 80:21-81:23. In 2005, Ms. Piper and Terri DeJong, the Aurora accounting department employee assigned to the Hudson Agreement, met for the first time to discuss the form of the Payout statement and the information included therein. Ms. DeJong provided Ms. Piper with a sample, previously approved by Aurora's management, and Ms. Piper accepted it. PX-188; Trial Tr. May 12, 2011, 125:11-14.

Ms. DeJong began preparing Payout statements using expense and gross revenue numbers to show net revenue, with a detailed breakdown of what items were included in gross revenue, and the various PPCs that were deducted to determine net revenue. Trial Tr. May 12, 2011, 136:24-137:3. Frontier continued to receive Payout statements for a little over two years, showing net proceeds and an increasingly-detailed breakdown of post-production expenses. Ms. Piper and Ms. DeJong met five times between 2005 and 2007 to discuss the Payout statements. According to Ms. DeJong, Ms. Piper agreed in January 2005 that the net revenue figure (rather than gross revenue) was the correct figure to include in calculating Payout. *See* Trial Tr. May 13, 2011, 43:11-14. In addition to Ms. Piper, family patriarch Melvin Nielson, and Keith and Cori Nielson were also reviewing the Payout statements. No one at Frontier objected to anything contained therein. Trial Tr. May 13, 2011, 131:24-133:18. Ms. Piper did, however, request "backup" documentation regarding all information included in the Payout calculations. DX-10A; DX-21; DX-45; PX-135. Aurora generally provided this information as requested.

In addition to determining whether Payout had been reached, Ms. Piper was also responsible for verifying the accuracy of the royalty payments that Aurora made. Trial Tr. May 13, 2011, 86:16-18. Aurora sent Frontier its first royalty payment in February 2005.

DX-210A. Ms. Piper also requested additional information regarding the breakdown of this payment. Trial Tr. May 12, 2011, 127:5-10. Ms. DeJong sent Ms. Piper a detailed accounting of the revenue and PPCs regarding the calculation of the royalty check including identifying HPPC transportation as a post-production expense. DX-172F. Again, no one at Frontier objected.

Aurora continued to provide Frontier with Payout statements and Frontier continued to review them and accept royalty checks without objection until May 2007. In the Payout statement provided to Frontier on May 22, 2007, the net revenue column showed for the first time that the Hudson NE Unit had reached Payout about a year before. On May 29, 2007 -- within one week of receiving this statement -- Keith Nielson, showing that he was monitoring royalty and Payout statements closely, wrote a demand letter to Rebecca Abbott, a contract manager at Aurora, stating that Frontier's royalty payment should have increased on June 1, 2006, and that the additional revenue plus interest was due and owing. PX-20.

In response to this Payout statement and the letter by Keith Nielson, Aurora sent a letter enclosing a revised Payout statement adding $4,344,041.19 under the "Development Expense" column. On July 31, 2007, Keith Nielson sent another letter stating that Frontier disagreed with this revision and the additional expense. PX-22.

The parties met in August 2007, at which time Aurora explained that the May 2007 Payout statement was wrong because it incorporated only part of the costs associated with the OIL acquisition that took place in 2006. Trial Tr. Dec. 13, 2010, 45:16-47:24. In other words, when Aurora and OIL both had a working interest in the Hudson Units, Aurora was paying about 48% of the costs, which was proportionate to its ownership interest of 48%. When it bought OIL's share of the working interest in the Hudson Units, it increased its share of the revenue to 96%, which reflected its increased ownership percentage, but it was still showing costs in proportion to its previous ownership interest of approximately 48%. Aurora contended that the Payout calculation should have reflected costs of 96% in proportion to its increased ownership share of 96%. This discrepancy is what made Hudson NE look as if it had reached Payout.

After the meeting, the parties agreed to use only the pre-OIL acquisition interest of Aurora of about 48% in both the revenue and expense calculation to determine Payout. Trial Tr. Dec. 13, 2010, 52:7-10. But even with this understanding, Frontier was becoming suspicious of the way Aurora was calculating Payout. Consequently, sometime after receiving the erroneous Payout statement in May 2007, Frontier retained counsel. On February 4, 2008, Frontier filed the State Court Action, alleging that Aurora had breached various obligations under the leases. Frontier sought money damages and an accounting.

IV. BURDEN OF PROOF & APPLICABLE LAW

As the party asserting that Aurora breached the Hudson Agreement, Frontier bears the burden of proving, by a preponderance of the evidence, the terms of the agreement, the breach of that agreement, and the damages it incurred.[3]

The parties have cited Michigan law to assist the court in resolving this dispute, and the court agrees that Michigan law supplies the rule of decision because there is a nexus between the parties, the contract and Michigan, and there is no federal purpose requiring otherwise. *See also* 28 U.S.C. § 1652 (state law supplies rule of decision in civil actions).

The over-arching purpose of contract interpretation is to determine the parties' intent at the time of contracting. *See* Aurora's Post-Trial Brief ("Aurora Br.") at p.42 (*citing Quality Prods. & Concepts Co. v. Nagel Productions, Inc.*, 666 N.W.2d 251 (Mich. 2003), *and Tenneco, Inc. v. Amerisure Mut. Ins. Co.,* 761 N.W.2d 846 (Mich. App. 2008)); *see also* Frontier Energy

[3] Given the complex nature of the calculations at issue, the parties agreed that the court's decision would primarily grant declaratory relief, rather than damages. After reviewing the court's decision, the parties' experts will calculate damages more specifically.

LLC's Post-Trial Brief ("Frontier Br.") at p.21 (*citing Klapp v. United Ins. Group Agency, Inc.*, 663 N.W.2d 447 (Mich. 2003)).

Because both Frontier and Aurora acknowledge that the Hudson Agreement is ambiguous in several material respects, they urge the court to apply varying contract interpretation principles. For example, Aurora relies heavily on the parties' "course of performance" as shedding light on their mutual interpretation of the Hudson Agreement. Aurora relies on *Detroit Greyhound Employees Federal Credit Union v. Aetna Life Ins. Co.*, 167 N.W.2d 274, 275 (Mich. 1969) (hereinafter "*Detroit Greyhound*"), wherein the Michigan Supreme Court gives more credit to the parties' course of performance before litigation than positions taken after a dispute arises and lawyers get involved.

Frontier, on the other hand, concedes that "course of performance" is relevant (Frontier Br. at p.23) but urges the court to apply the public-policy based rule, specific to oil and gas leases, that construes ambiguities in favor of the lessor. *See, e.g., J.J. Fagan & Co. v. Burns*, 226 N.W. 653, 681 (1929) ("[O]il and gas leases are to be construed for the benefit of the lessor and against the lessee," citing Summers, Oil and Gas (1927) 372); *McClanahan Oil Co. v. Perkins*, 6 N.W.2d 742, 743 (Mich. 1942); *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887, 892 (Mich. App. 1997); *Boyer v. Tucker & Baumgardner Corp.*, 372 N.W.2d 555, 556 (Mich. App.1985).[4] Aurora challenges Frontier's cases as outdated and abandoned by the authors of the cited texts. *See* Aurora Br. at p. 44, n.14 (criticizing the *J.J. Fagan* decision and citing 2 Summers Oil & Gas § 16:2 (3d ed. 2010)).

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[4] With less emphasis, Frontier also urges the court to consider trade usage and apply the well-worn principles of *ejusdem generis* (of the same kind or nature) and *expressio unius est exclusio alterius* (the expression of one thing is the exclusion of the other). *See* Frontier Br. at 21. Frontier also relies on a relatively recent Michigan statute, M.C.L. § 324.61503b (allowed deductions from lessor's royalties and postproduction costs in gas leases), as an additional interpretative aid with respect to some of the disputed payout issues. *Id.*

Federal courts, however, are not free to abandon the policy choices expressed by a state's highest tribunal, even if the academic community is not so constrained, and even if the court were inclined to make different choices. *See* 28 U.S.C. § 1652 (state law generally supplies rule of decision in federal civil litigation). Moreover, the parties expressly incorporated "applicable law" as a part of the Hudson Agreement, a term the court regards as including Michigan case law, but not academic writings. The court finds, therefore, that despite the evolving understanding of certain oil and gas scholars, Michigan case law continues to permit the court to construe ambiguous terms in the Hudson Agreement against Aurora, the lessee, as a matter of public policy.

That being said, however, the court does not interpret the rule in *J.J. Fagan* as "lessor always wins" or "other contract interpretation principles need not apply." *See McClanahan*, 6 N.W.2d at 743 ("Oil and gas leases have some terminology not found in other contracts but . . . ordinary rules of construction of contracts govern."). Furthermore, the court rejects Frontier's conclusion that *McClanahan* elevates the rule of construction in *J.J. Fagan* over other rules of contract interpretation. *See* Frontier Br. at 22 ("Ordinary rules of construction apply, but only after resolving any ambiguities strictly in favor of the lessor."). Frontier does not explain what role would remain for the other "ordinary rules of construction" after the *J.J. Fagan* rule is applied, if all ambiguities are reflexively resolved in a lessor's favor every time there is an uncertainty. More logically, the *J.J. Fagan* rule is but one of several rules the court may bring to bear in resolving this controversy. *See, e.g., Schroeder*, 565 N.W.2d at 892-94 (noting rule in *J.J. Fagan*, but construing ambiguity in favor of the Defendant-lessee in part "because it better conforms to the parties' intent as gleaned from the contractual language."); *Lomree, Inc. v. Pan Gas Storage, LLC*, 2011 WL 3498131, 4 (E.D. Mich., August 10, 2011) ("if after applying all other conventional means of contract interpretation, including the consideration of extrinsic evidence, the terms are still ambiguous, the rule of *contra proferentem* applies . . . ."); *City of Grosse Pointe Park v. Michigan Municipal Liability and Property Pool*, 702 N.W.2d 106, 113 (Mich. 2005) (*citing McIntosh v. Groomes,* 198 N.W. 954 (Mich. 1924) ("The cardinal rule in the interpretation of contracts is to ascertain the intention of the parties. To this rule, all others are subordinate."). Consequently, the court finds that the unique rule of *J.J. Fagan* must yield to other interpretive rules designed to ascertain the objectively manifested intent of the parties.

As a practical matter, this means the court will first apply the applicable rules of contract interpretation cited by the Michigan courts involving controversies between parties to oil and gas leases, such as trade usage and/or course of performance. Then, only if these interpretative aids fail, will the court resolve ambiguities in favor of Frontier as lessee.

V. THE HUDSON AGREEMENT

Case law from the oil and gas arena, as well as the testimony at trial, establish that oil and gas leases in Michigan differ from other contracts because there is a widespread use of standard oil and gas lease forms. The language in those forms has "evolved through the process of trial and error with careful attention being paid to judicial decisions interpreting the standard contractual verbiage." *See Schroeder*, 565 N.W.2d at 891 (*citing J.J. Fagan*, 226 N.W. 653, and *Michigan Wisconsin Pipeline Co. v. Michigan Nat'l Bank*, 324 N.W.2d 541 (Mich. App. 1982)).

Indeed, the Hudson Agreement relies to a considerable extent on a standard oil and gas lease form for many customary purposes, such as identifying Frontier as the "Lessor" and Aurora as "Lessee," and specifying the lands and acres leased by reference to an addendum. In addition, it includes many standard definitions, such as "Drilling Unit," "Gas," "Marketable Condition" and "Production Unit," among other terms. It specifies the term of the lease, rental payments, provisions for "shut-in wells," default, and a number of other aspects of the parties' relationship not directly involved in their dispute.

But then, at Frontier's insistence, the parties departed from the form lease in several material respects. More specifically, they undertook to abandon the form lease's straight-forward royalty provision in favor of one of their own creation that provides, in relevant part, as follows:

> Lessor's royalty shall be free of all costs excepting those costs incurred by lessee for CO_2 removal, third party transportation, and necessary compression. Also note that the state tax exception in paragraph C.2.g of this lease does not apply to Frontier Energy LLC.

PX- 1 at Exhibit A, ¶ 6.

The parties also departed from the standard lease when they developed the concept of "Payout" as an event that triggered Frontier's right to receive escalating royalties as a "function of the price" Aurora charges for gas, instead of at a fixed-rate of 15%. Perhaps not surprisingly, when they departed from the form lease in memorializing material provisions of their agreement, they opened the door to disputed interpretations of some of the key terms of their bargain.

VI. DISPUTED ROYALTY ISSUES

By including special terms within Exhibit A of the Hudson Agreement, the parties endeavored to prescribe permissible deductions from Frontier's initial 15% royalty. Although the "CO_2 removal" deduction did not generate any controversy in connection with the royalty calculation, the deductions for "third party transportation" and "necessary compression" have consumed thousands of hours and many thousands of dollars. In a nutshell, Frontier regards these two phrases as ambiguous, and urges the court to construe them in its favor as lessor.

A. Third Party Transportation.

Throughout the parties' relationship, Aurora has obtained services from HPPC to move gas from the various wells to processing facilities and, ultimately, to market. The evidence established beyond cavil that HPPC was at all relevant times closely related to Aurora as a subsidiary, although Aurora's ownership interest varied during the period at issue. While HPPC is a formally separate legal entity, it has in many ways been controlled by Aurora. Indeed, Aurora undertook to significantly reallocate HPPC's assets, and at one point even pledged HPPC's assets to secure its own debt without observing any corporate formalities. Trial Tr. March 7, 2011, 136:5-18; *id.*, 145:13-146:3; Deposition Tr. Nov. 18, 2010 (Russell L. Lawson), 15:25-16:12; *id.*, 19:24-20:6. Frontier has attempted to persuade the court to disallow deductions from its royalty for payments made to HPPC because of this close relationship with Aurora.

When interpreting contracts, Michigan courts must "determine the intent of the parties by examining the language of the contract according to its *plain and ordinary meaning*." *In re Smith Trust*, 745 N.W.2d 754, 757-58 (Mich. 2008) (emphasis added). The "plain and ordinary meaning" of the term "third party" is someone "other than the principals involved in a transaction." *See, e.g.,* American Heritage Dictionary (3d ed. 1996 Houghton Mifflin Co.). Here, HPPC was not a signatory or party to the Hudson Agreement.

The court rejects Frontier's argument as inconsistent with the commonplace meaning of "third party" even though the evidence showed a close nexus between the two entities. Nothing presented at trial persuaded the court to ignore the separate corporate identities of Aurora and HPPC. As such, the court finds that in a common sense, ordinary meaning of the term, HPPC is a "third party" with respect to Aurora. It is not a party to the Hudson Agreement.

Frontier's argument is also inconsistent with the language within the Hudson Agreement because the parties used the related but distinct term "independent nonaffiliated third party" in the standard lease form's royalty provisions of their agreement. *See* PX-1, § C.2.e. and C.2.f. This use, especially within the royalty section of the main document, confirms that the parties knew how to distinguish related and unrelated third parties, and from the language of the contract, they in fact did so. The court is unwilling to use the pre-contractual drafts that Frontier offered into evidence, or the Nielson Brothers' undisclosed intention to limit the deduction to "independent nonaffiliated" third parties, to create an ambiguity in the agreement as executed. Because the Hudson Agreement uses the term "third party" (unmodified in one section but modified in another), the court does not regard the contract as containing either a patent ambiguity -- one evident from the face of the document itself -- or a latent one -- apparent from some extrinsic fact. *Shay v. Aldrich*, 790 N.W.2d 629, 641 (Mich. 2010).

Furthermore, to the extent Frontier is actually arguing that the Hudson Agreement should be reformed to reflect Frontier's true intent, the court rejects the argument as not pled and unpersuasive. Reformation of written instruments is a matter of equity, and generally involves fraud or mutual mistake of fact not proven here. *Najor v. Wayne Nat'l Life Ins. Co.*, 178 N.W.2d 504, 511 (Mich. App. 1970). At most, the testimony of the Nielson Brothers, if credited, would establish that the Agreement did not accurately reflect the subjective intent of Frontier, but that mistake was not mutual.[5]

Because the Hudson Agreement contains limitations for "independent nonaffiliated" third parties in some, but not all, parts of the document, the court assumes each term has a distinct meaning in context, and will not infer that Aurora was mistaken in executing the Hudson

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[5] The court doubts the trial testimony of David and Dale Nielson because it is at odds with their prior deposition testimony in which they lacked a specific recollection of the negotiations. In addition, David Nielson's testimony at trial showed that he served more as a messenger, which makes his earlier lack of recollection infinitely more credible than his recovered memory just in time for trial.

Agreement with Exhibit A as drafted. Therefore, all deductions from Frontier's royalty for costs incurred by HPPC for third party transportation are allowed.

B. Necessary Compression.

Frontier also contends that the Hudson Agreement precludes Aurora from deducting "first stage" compression expenses on the theory that Aurora located the booster compressor at the wellhead because it affects back pressure at the well and helps to induce the gas to leave the ground. Therefore, its primary purpose is to stimulate gas production rather than compress it and consequently it does not qualify as a PPC. On Frontier's theory, first stage compression is a cost of production that Frontier, as a royalty owner, should not bear. Aurora contends, in contrast, that the booster compressor is necessary for first stage compression, and that compression must take place in stages lest the gas heat up too much all at once. The booster compressor must be located at the wellhead because that is where the first stage of compression takes place. Further, argues Aurora, by definition, the first stage of compression is necessary to any compression, and the fact that it stimulates production is just a happy coincidence.

Frontier is correct in that, as a general matter of industry custom, lessees or operators (such as Aurora) bear the cost of producing natural gas and lessors (such as Frontier), bear certain, negotiated PPCs. Trial Tr. Dec. 9, 2010, 190:6-13. Indeed, the royalty clause in the Hudson Agreement lists three permissible deductions, two of which are indisputably PPCs -- CO_2 removal and third party transportation -- suggesting under the interpretative principle known as *ejusdem generis* that Aurora may deduct only *post-production* compression costs, and then, only necessary compression costs. This is a fair reading of the Hudson Agreement and the one the court adopts.

The question then becomes whether the so-called "first stage" compression costs associated with the "screw" or "booster" compressors located closer to the well-heads constitute lease operating costs (*i.e.,* production costs), or PPCs. Aurora may not deduct the former from Frontier's royalty, but may deduct the latter.

At trial, the court gave Aurora's witness, John Hunter, considerable latitude to describe the role and effect of compression in Aurora's Antrim projects. He explained that the first-stage compressors differ from the compressors located at the central processing facility in that the former use a screw or auger-like mechanism and the latter use mechanisms more akin to pistons, as in an automobile engine. In addition, and more significant than the type of compressor, is the suggestion that Aurora located the first-stage booster or screw compressors close to the various well-heads in part because of difficulties that it experienced with negative back pressure or vacuum at the well. As Mr. Hunter explained, gas flows from higher pressure to lower pressure, and the court infers that negative pressure at the well-head would impede the progress of the gas from the ground into the processing chain. To some extent, the booster compressors have a positive impact on Aurora's removal of the gas from the ground, suggesting that they play a role in production, rather than post-production. Standing alone, however, this incidental effect on the pressure at the well does not persuade the court to regard first stage compression as a lease operating expense.

Frontier points out, however, that for the first four years of the parties' relationship, Aurora itself treated first-stage compression as a lease operating expense rather than a post-production expense. *See, e.g.*, PX-69 (Midstream Asset Project Progress Report and Proposed Business Plan).[6] The documents included in PX-69, which describe Mr. Lawson's efforts to

[6] Frontier cites PX-69 in its post-trial brief, *see* Frontier's Br. at p.50, even though the court did not admit that exhibit.

reform the accounting practices of Aurora and HPPC and rationalize the asset allocation between the entities, plainly recite that for several years Aurora treated first stage compression as a lease operating expense, rather than a PPC. Mr. Lawson notes, however, that "Aurora has not been appropriately segregating these costs and has been reporting a significant amount of post-production cost as lease operating expense." *Id.* Frontier is attempting to seize on this early and reportedly erroneous accounting treatment as evidence that the first-stage or booster compression is not, in fact, a PPC, and that the "course of performance" dictates a similar conclusion from the court.

As the court noted above, the "course of performance" is generally an aid in interpreting an ambiguous contract term, but here the court has already concluded that only PPCs may be deducted from Frontier's royalty. Therefore, rather than asserting course of performance as an aid in contract interpretation with respect to the first-stage compression issue, Frontier is actually asking the court to infer from Aurora's early accounting treatment that the booster compressors are in fact used in the production, rather than the post-production phase of Aurora's business. The evidence, however, does not preponderate in Frontier's favor on this point.

First, the parties agree (and the Hudson Agreement confirms) that compression costs are generally PPCs. Second, the very document upon which Frontier relies (PX-69) as evidence that Aurora did not initially deduct first-stage compression costs describes the prior treatment as an accounting mistake. Testimony from Bill Deneau, Aurora's former CEO, confirms that Aurora had engaged Mr. Lawson to rationalize the accounting and asset allocation among Aurora and HPPC, and the court has no reason to believe that Mr. Lawson's accounting changes were driven by this litigation or anything other than Mr. Deneau's charge to clean it up. Third, the fact that the compressors had an incidental effect on back-pressure at the well-head does not preclude a finding that the costs are post-production. There was general agreement among the witnesses that compression must take place in stages given the nature of the process, and that compression must take place to move the gas after it leaves the ground. To a considerable extent, first-stage compression serves a post-production function.

Having reviewed the record, the court is not inclined to treat an accounting mistake as persuasive evidence that compression -- presumptively a PPC under the parties' own agreement -- as a lease operating expense. *Schroeder*, 565 N.W.2d at 896 (mistakes not relevant to interpretation). The evidence shows that Aurora was aware of accounting errors affecting its bottom line, and was taking steps to correct them, systematically, without regard to its dispute with Frontier.

For these reasons, the court finds that Frontier has not met its burden of proving that Aurora inappropriately deducted first-stage compression expenses from the royalty and the court will allow them to stand.

C. Rates for CO_2 and Compression.

While working for HPPC, Russ Lawson calculated the rate for CO_2 removal to be $0.20 per Mcf. He based this on comparable rates charged at the Warner Plant. Deposition Tr. Nov. 18, 2010 (Russell L. Lawson), 41:4-12. Later, Mr. Lawson discovered that this rate was far below market price and that HPPC was actually losing money by charging this price. *Id.* at 43:4-44:11. Even so, Aurora continued to charge Frontier CO_2 processing at this rate.

Nevertheless, Frontier believes that the rates HPPC charged Aurora for CO_2 removal and compression were above-market price, and because of the relationship between Aurora and HPPC, Aurora should have discounted its charges by 20%. Frontier asserts that the charges are above market rates because DTE, the operator of the Warner Plant, charges $0.11 per Mcf for firm processing and $0.20 per Mcf for interruptible processing. Frontier claims that the processing provided by HPPC is more akin to firm processing and should therefore be charged at or closer to that price. As far as the amount of the discount, Mr. Martindale, Frontier's expert, says the 20% discount is "a means of estimating actual costs," at least in the joint venture context, based on the Counsel of Petroleum Accountants Societies ("COPAS") model for joint operating agreements.

The court is not persuaded that $0.11 per Mcf is an appropriate measuring rate because, as Mr. Russell credibly explained, DTE arrived at this rate in order to settle a lawsuit. Trial Tr. May 19, 2011, 139:2-140:2. The court is also not willing to infer an appropriate market rate based only upon a figure that likely reflects reasons other than market factors, such as costs and risks of litigation, and other non-market considerations. Moreover, testimony from Mr. Russell, based upon his discussions with Mr. Lawson, explains how Aurora arrived at the $0.20 per Mcf, after calculating the costs of the compressors, the maintenance costs, useful life, forecasting the volume of gas to be processed, and amortizing the costs and benefits over the life of the asset. Trial Tr. May 19, 2011, 136:19-137:18.

The court also notes that the royalty provision of the Hudson Agreement includes no "market rate" limitation, but instead requires only that the CO_2 removal cost be a cost "incurred by the Lessee." Frontier does not dispute that Aurora incurred costs at this rate, but rather because Aurora exercised control over the rate-setter, the rates charged should have been lower.

To the extent that Frontier is suggesting a reasonably prudent operator would have charged less than $0.20 per Mcf, the court has already rejected those claims in its Rule 52 ruling after the close of Frontier's proofs. As noted then, the Plaintiff offered no evidence of a yardstick or standard against which the court might evaluate whether Aurora was a prudent operator.

Similarly, with respect to Frontier's proposal to reduce the royalty deduction by 20% based on the COPAS standard in the joint-venture setting, the court is not persuaded. First, there is no basis in the Hudson Agreement for the discount that Frontier proposes or for incorporating the COPAS standards to begin with. If Aurora incurred the costs, even if they were charged by its subsidiary, and even if Aurora might eventually derive a benefit from those charges, it still incurred the costs. Frontier did not bargain for any special protection with respect to charges for CO_2 and compression. Although joint venturers certainly may agree to discount charges they pass on to each other to account for affiliate transactions, there is no evidence that Aurora and Frontier ever contemplated this sort of discount or protection, and the court will not incorporate the COPAS standard simply because, in retrospect, Frontier wishes it had.

Accordingly, the court finds that the charges by Aurora for CO_2 and compression were reasonable and proper.

VII. DISPUTED PAYOUT ISSUES

Although "payout" clauses are not unknown in the oil and gas industry, they tend to be idiosyncratic and non-uniform. The Payout Clause in this case is no exception. Determining what point in time Aurora achieves Payout has a dramatic effect on the parties' rights because Frontier may be entitled to a higher royalty rate after Payout, depending on the market price for gas. Frontier described the concept of Payout, generally, as "the point at which a group of wells (called a 'Unit') becomes profitable." *See* Brief in Support of Plaintiff's Motion for Partial Summary Disposition at p. 4 (DN 118-1). Because the Payout Clause is central to understanding this controversy, the court sets it out in full:

5. Notwithstanding anything contained in this lease to the contrary, lessor's royalty on production from any Antrim Unit established under the terms of this lease shall be determined in accordance with this paragraph.

Before Payout

Lessor's royalty on production occurring Before Payout shall be fifteen percent (15%) of the proceeds of sale.

After Payout

Lessor's royalty on production occurring After Payout shall be a function of the price for which the gas is sold by lessee as specified below:

a) Fifteen percent (15%) of the proceeds of sale attributable to a price up to and including $2.50 per MMbtu.

b) Twenty-Five percent (25%) of the proceeds of sale attributable to a price greater than $2.50 per MMbtu and up to and including a price of $3.50 per MMbtu.

c) Fifty percent (50%) of the proceeds of sale attributable to a price in excess of $3.50 per MMbtu.

Note: as clarification, 15% royalty is to be applied to the first $2.50 per MMbtu regardless of the total sales price.

Lessee covenants and agrees to use its commercially reasonable best efforts to sell the gas at the best price obtainable under the circumstances, or Lessor may receive its royalty in kind to market at a higher price. For purposes of this paragraph, the term "Payout", with respect to a given Antrim Unit, shall mean the point in time that the proceeds of production attributable to the interest of lessee in all wells drilled upon the Antrim Unit, less royalties and other lease burdens and production or similar taxes, equals the costs incurred by lessee for drilling, testing, completing and equipping all wells, constructing and installing all necessary gathering lines, facilities and pipelines, including meters, plus the cost of operating the Antrim Unit prior to Payout. Payout for royalty determination purposes shall be deemed to have occurred as of the first day of the calendar month succeeding the month in which payout occurs.

PX-1 at Exhibit A, ¶ 5. To summarize, the parties agreed that before Payout, Frontier's royalty rate would be 15% of the *proceeds of sale*, and after Payout, it would be between 15-50%, depending upon the sale price of the gas. For purposes of determining when Payout occurs, however, the parties used the phrase "proceeds of production" (rather than "proceeds of sale") as the measuring point. Frontier contends that the two phrases are synonymous; Aurora disagrees.

They also disagree about the precise percentages of costs and revenues to use in calculating Payout, given that Aurora leased some of the land comprising the various Hudson Units from entities other than Frontier. This dispute also presents a question of contract interpretation.

In addition, Frontier challenges Aurora's effort to deduct numerous expenses, such as lease-related expenses, legal and landman expenses, and certain engineering and other technical expenses when determining whether any of the Hudson Units has reached Payout.

A. The Effect of M.C.L. § 324.61503b on Payout.

Frontier argues that M.C.L. § 324.61503b requires the court to construe the Payout Clause against Aurora. Frontier's theory is that the Payout Clause affects the royalty payment, and therefore M.C.L. § 324.61503b applies. It provides in relevant part as follows:

> (1) A person who enters into a gas lease as a lessee after March 28, 2000 shall not deduct from the lessor's royalty any portion of postproduction costs unless the lease explicitly allows for the deduction of postproduction costs. If a lease explicitly provides for the deduction of postproduction costs, the lessee may only deduct postproduction costs for the following items, unless the lease explicitly and specifically provides for the deduction of other items:
>
> (a) The reasonable costs of removal of carbon dioxide (CO_2), hydrogen sulfide (H_2S), molecular nitrogen (N_2), or other

> constituents, except water, the removal of which will enhance the value of the gas for the benefit of the lessor and lessee.
>
> (b) [specified] Transportation costs . . .

M.C.L. § 324.61503b(1). It appears that Michigan's legislature may have intended to address a specific oil and gas lease drafting problem by overruling the decision of the Michigan Court of Appeals in *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887 (Mich. App. 1997) with this statute. The legislative history is silent regarding any response to *Schroeder*.

Regardless of the actual legislative history or purpose of the statute, the court cannot accept Frontier's broad view of the statute's effect. First, and most generally, statutes in derogation of the common law are narrowly construed. *Rusinek v. Schultz, Snyder & Steele Lumber Co.*, 309 N.W.2d 163 (Mich. 1981). Second, the somewhat unusual concept of "Payout" is simply not addressed within the text of the law, which is concerned with permissible deductions for royalty payments. The Payout Clause in the present case is not intended to reduce Frontier's royalty, but to augment it, depending upon market prices for natural gas. In short, the language of the statute does not restrict the parties' ability to negotiate for an escalating royalty rate that serves to benefit lessors. The language simply does not stretch as far as Frontier's novel argument would take it.

B. <u>Calculating Ownership Percentages for Payout Purposes</u>.

At the most basic level of the dispute, the parties disagree about the appropriate ownership percentage to be used in making the Payout calculation. At trial, they sparred regarding the actual acreage that Frontier has leased to Aurora with respect to the Hudson Units. The court heard from Rebecca Abbott, Aurora's "landman," who persuasively testified about the amount of acreage within each Hudson Unit, including Frontier's share of leased property, and the resulting net revenue interest ("NRI") that Frontier has in each Unit. Trial Tr. March 7, 2011, 190:10-191:7; 196:20-25. She explained the detailed and meticulous process she used to determine Frontier's share (and calculate its NRI), by reviewing land records, leases, surveys, legal descriptions and related data to arrive at her conclusions regarding Frontier's NRI for each unit. Frontier did not offer any comparably persuasive evidence for its view of the NRI percentage. Ms. Abbot impressed the court as an experienced, knowledgeable, and credible witness. The court credits this testimony, and shall accept Ms. Abbot's conclusions as summarized in the following table:

Hudson Unit:	H34	HSW	HNE	H19	HNW	H13
Frontier NRI %	41.336724	30.851004	46.869758	78.143438	57.672945	22.710336

See PX-55, § IV.B.1.

Closely related to Frontier's NRI in each Hudson Unit is the corresponding interest of Aurora, sometimes referred to as its gross working interest. This is the figure, expressed as a percentage that the oil and gas accountants use to allocate revenues and expenses derived from each of the Hudson Units. It is also the figure that the parties agreed to use in calculating Payout. In their agreement, they used the following language to describe Aurora's share: "the interest of the lessee in all wells drilled upon the Antrim Unit." *See* PX-1, p. 11, ¶5..

According to Frontier, however, "the gross revenues and expenses for each unit must be multiplied by the percentage of the Hudson Lease's acreage in each unit." *See* Frontier's Br. at 75; *see also* Trial Tr. May 19, 2011, 104:17–105:8. Mr. Russell helpfully explained Frontier's position as follows: "Mr. Martindale had taken the approach that the payout should be limited -- the ownership interest included in payout should be limited to a calculation of only Frontier's acres divided by the total unit acres." *Id.*, 104:21-24. On the other hand, Aurora argues that the gross revenues and expenses for each unit should be multiplied by the percentage of all acreage Aurora has leased in each unit, not just acres leased from Frontier. *Id.,*105:1-8. In support of its position, Aurora reminds the court that, on the revenue side, the Payout Clause refers to "the proceeds of production attributable to the interest of lessee in *all* wells drilled upon the Antrim Unit . . . ." PX-1, p.11 (emphasis added). In other words, the use of the term "all" includes wells on land leased from lessors other than Frontier. On the expense or deduction side of the Payout equation, the parties also employed the word "all" when they permitted deductions for "costs incurred by lessee for drilling, testing, completing and equipping all wells." *Id.* According to Aurora, "all" means "all."

Frontier, however, takes a different tact, relying on the following clause, found at paragraph 7 of the addendum to the Hudson Agreement: "[t]his lease covers only those lands that are specifically described and no provision of this lease shall operate to extend coverage of the lease to contiguous or appurtenant lands that are not specifically described." *See* PX-1, p.2; Trial Tr. May 12, 2011, 78:4-5; Trial Tr. May 19, 2011, 106:17-24.

Frontier's argument completely misses the mark. First, the credible testimony of Mr. Russell explained that this is a so-called "anti-Mother Hubbard clause," widely used in Texas and elsewhere to address a problem of inaccurate property descriptions. Even without crediting this explanation, the court has no difficulty concluding that paragraph 7 to the addendum will not bear the weight that Frontier places on it. The Payout Clause simply measures an event -- "Payout" -- by reference to revenues and costs associated with "all" of its wells in a particular Hudson Unit. It does not purport to extend the lease to Frontier's contiguous or appurtenant lands, and its effect is confined to the lands described in Exhibit B to the Hudson Agreement. PX-1. The plain language of the Hudson Agreement makes Payout contingent upon Aurora's revenue and its expenses associated with "all wells" within each Hudson Unit. There is nothing ambiguous about the word "all."

Even if there were some ambiguity, the fact that Aurora consistently included revenues and expenses from other wells within each respective unit, and that Frontier was aware of this, confirms the parties' mutual and reasonable understanding of the Payout Clause. Like so many disputes in this adversary proceeding, the origins of discrete controversies seem to coincide with the retention of legal and accounting professionals, hearkening back to the Michigan Supreme Court's perceptive remark in the *Detroit Greyhound* case: courts favor inferences drawn from the parties' own conduct occurring "before new and technical interpretative thoughts reared themselves for litigatory controversy." *Detroit Greyhound*, 167 N.W.2d at 278.

The language of the Hudson Agreement favors Aurora's interpretation on this issue.

C. Proceeds of Production: Gross or Net?

The next aspect of the parties' Payout dispute requires the court to determine whether the term "proceeds" as used in the Payout Clause is ambiguous, *i.e.,* whether it means proceeds net of PPCs as Aurora argues, or "gross" proceeds, as Frontier insists. The court concludes that the term is ambiguous because the language is susceptible to more than one meaning. Therefore, the court must resort to interpretive aids, such as the parties' course of performance among other tools.

Frontier's argument is premised on the *expressio unius est exclusio alterius* principle: by expressing certain deductions – "royalties and other lease burdens and production or similar taxes" -- the parties excluded others, such as PPCs. Indeed, the structure of the clause tends to support Frontier's interpretation, unless the phrase "proceeds of production" itself imports the concept of netting-out PPCs. Thus, the court must determine the meaning of "proceeds of production."

Mr. Russell credibly testified that the term "proceeds of production" is a term of art the industry coined to describe the value of the gas "at the wellhead." Trial Tr. May 20, 2011, 42:7-23. According Mr. Russell's plausible explanation, gas in its natural or unprocessed state at the wellhead is worth less than gas at the point of sale because the latter has been improved for marketing through post production activities. By referring to the point of production -- at the wellhead -- the phrase means before adding the value that industry players know as PPCs. Therefore, the phrase "cost of production" itself imports the concept of netting out PPCs to segregate the value added through the refining process from the value at the well.

Dale Nielson's trial testimony in which he said the terms "proceeds of sale" and "proceeds of production" meant the same thing, rings hollow for a number of reasons. The evidence shows that the Hudson Agreement was the product of much negotiation between sophisticated players. So, the court is naturally inclined to infer under these circumstances that the parties chose their words carefully. When different phrases occur within the same paragraph, a court should hesitate to equate their meaning. Moreover, the Nielson Brothers' trial testimony was surprisingly more detailed and complete than their deposition testimony on these points, leading the court to doubt their veracity, or at least attribute their testimony more to trial preparation than actual recollection of historical fact.

Again, the manner in which the parties conducted themselves before this dispute arose speaks volumes about what they meant when they inked their deal. Specifically with respect to the propriety of deducting post-production and other costs in calculating Payout, the documentary evidence shows that Aurora consistently deducted such costs from the outset, and

Frontier received the statements for three years without complaint. Trial Tr. May 12, 2011, 123:9-124:4; 135:8-136:20; 145:1-15; 147:10-20; 148:4-21; 153:2-12; 157:24-158:15; 179:4-13; 182:20-183:17; 188:6-14; 190:7-16; 194:6-22. Ms. Piper, the experienced oil and gas professional charged with reviewing the statements, "pored over" the documents and was familiar with the Hudson Agreement. She also shared the information with her superiors. Yet, for several years, Frontier never complained.

Indeed, Ms. Piper repeatedly requested documentation of the PPCs, confirming that she accepted the fact of the deductions while seeking to verify the amounts. From the evidence, the court finds that the primary role of Frontier's management company, Generations Management, and its oil and gas accounting specialist, Ms. Piper, was to track royalty payments and Payout to ensure that Aurora hewed closely to its obligations under the Hudson Agreement.

Frontier's later interpretation of the Payout Clause in a manner inconsistent with its pre-litigation conduct is precisely the sort of *post hoc* rationalization that the Michigan Supreme Court criticized in *Detroit Greyhound* where it favored reliance on "mutually agreeable performance" that took place long before someone, with an eye on the courthouse, put a new spin on the agreement. *Id.*, 167 N.W.2d at 278.

The court finds that the phrase "proceeds of production" means proceeds of sale, minus PPCs, and therefore Aurora's deductions of PPCs in calculating Payout was consistent with the Hudson Agreement.

D. <u>Lease Bonus, Lease Rental, Lease Extension Payments</u>.

Aurora has also deducted costs associated with lease bonuses, lease rentals, and lease extension payments made in connection with other leases within the Hudson Units. Frontier and its expert, however, contend that these expenses do not qualify as "costs incurred by lessee for drilling, testing, completing and equipping all wells, constructing and installing all necessary gathering lines, facilities and pipelines, including meters . . . ." PX-1, Exhibit A at ¶ 5.

At the threshold of this discussion, the court notes that this phrase is broad and ambiguous. To resolve the ambiguity, the court will once again look to the parties' course of performance, and other interpretative aids.

The record establishes that Aurora included these charges in its payout calculation from the outset suggesting that, before litigation, Aurora regarded these charges as appropriate deductions. This early performance, even though unilateral at that point, is entitled to some weight as evidence of pre-litigation interpretation -- before the lawyers and other professionals got involved. For its part, Frontier requested and received documentation from Aurora in October 2005. *See* DX-10A #5 (Ms. Piper asks for documentation regarding 100% of LOE and Development Expenses in October 2005); DX-172G; DX-211 (supporting documents supplied in October 2006). The parties met several times after Frontier received this information, and there is no evidence that Frontier expressed any disagreement regarding these sorts of expenses being included in the Payout calculation, suggesting that before the parties' hardened their positions, they jointly regarded the Hudson Agreement as permitting Aurora to deduct a broad variety of costs in calculating Payout. The course of performance supports Aurora's decision to include these expenses, as does the nature of the costs.

Concededly, lease bonuses, lease rentals, and lease extension payments are costs generally associated with securing and preserving oil and gas leaseholds prior to commencement of actual production. From an accounting perspective, according to Mr. Martindale, these are "capital expenses for the leasing of the mineral interests, not drilling expanses [sic]." PX-53, Exh. B, Exception 1. But, as Rebecca Abbott and John Hunter credibly explained, the process of drilling a well involves numerous tasks: researching real estate records and land titles, surveying and engineering, obtaining permits, clearing land, building roads, and similar activities ancillary, but closely related, to the act of "spudding" or boring the drill bit into the ground. From time to time during the process, working interest owners must obtain leaseholds or other real estate interests in nearby parcels in order to meet geological, practical, and regulatory demands as a prerequisite to drilling.

Although the term "drilling" perhaps conjures images of the discrete act of plunging a drill bit into the ground, according to credible testimony the term and the drilling process is infinitely more complex. The court infers that Frontier, as a self-proclaimed sophisticated participant in the oil and gas business, understood this.

Moreover, the rather narrow interpretation of the drilling-related costs that Frontier urges the court to adopt is utterly inconsistent with Frontier's own general description of the concept of "Payout" as the point at which a unit becomes profitable. *See* Brief in Support of Plaintiff's Motion for Partial Summary Disposition at p. 4 (DN 118-1). Indeed, the word "Payout" itself is imbued with the notion of investment-recapture. Adopting Frontier's restrictive view would not effectuate the obvious intent of the parties -- to entitle Frontier to share in the market upside *after* Aurora recovers its investment in each of the Hudson Units. Honoring contractual intent, the court finds that these charges were contemplated in the contract and will be allowed to stand.

E. Landman, Legal, Title, and Engineering Charges.

The court regards the parties' dispute over the propriety of landman, legal, title and abstracting charges as virtually identical to their dispute about including engineering, geological, geophysical charges, and the lease bonuses and extension payments just discussed. Each disputed cost must qualify as a cost "incurred by lessee for drilling, testing, completing and equipping all wells, constructing and installing all necessary gathering lines, facilities and pipelines, including meters . . . ." PX-1, Exhibit A at ¶5.

As with lease bonus, rental, and extension payments, Aurora's witnesses explained that as lessee. Aurora incurred real estate-related expenses throughout the drilling process, including expenses for landmen, lawyers, abstracting, title commitment, division order title opinions and the like. Trial Tr. March 7, 2011, 174:15-181:14.

Similarly, as Mr. Hunter explained, through the life of a particular unit, and closely related to actual drilling, working interest owners must call upon the services of geological and geophysical professionals to determine where, precisely, to locate wells so as to comply with the physical requirements of a particular site and the regulatory requirements of the State. Credible testimony established that the Antrim Shale has an idiosyncratic feature described as "glacial scours." As Mr. Hunter explained, these scours are close to the bedrock where glaciers or pre-historic riverbeds have eroded the gas producing materials in isolated sections of the substrata, creating a Russian-roulette-drilling situation -- many wells could reach productive members without incident, but occasionally the driller might encounter a scour. The possibility that Aurora might expend considerable resources "spudding" or "boring into the ground only to find the unhappy surprise of a glacial scour prompted the company to pay for gravity and electromagnet surveys and similar geological testing to avoid this result. Trial Tr. March 7, 2011, 44:2-4; 96:15-21.

Although Mr. Hunter had not relocated to Traverse City from Texas until 2007, he was employed by Aurora in 2005 and "shuffled back and forth" for the early years of his employment, familiarizing himself with the Hudson Units as the supervisor of those Aurora employees more directly involved in the project. The court regards his testimony as helpful and persuasive.

Frontier, on the other hand, challenges Mr. Hunter's involvement in the Hudson Units as remote in time and location, but fails to offer any persuasive evidence of its own to establish that these engineering and geophysical charges are more closely-associated with exploration (a more speculative antecedent activity) rather than drilling. Mr. Martindale's accounting background and general understanding that engineering and geophysical services are associated with wildcatting and exploration do not persuade the court on the record presented to exclude these charges. Therefore, they are appropriate.

F. Overhead.

The disagreement regarding overhead differs slightly from the other disputes just described because Aurora changed its treatment of overhead over the course of the parties' relationship. In addition, overhead is, to a considerable extent, a cost that Aurora would incur simply by opening its doors, running its business, and developing wells other than those within the Hudson Units. The indirect and inescapable nature of overhead expense and the difficulty in measuring such expense also contributes to the conceptual challenges that the parties have experienced in grappling with this issue.

The parties' experts, both accountants, agree that overhead is a true cost of doing business, albeit an indirect one, including the business of developing and operating natural gas wells. The experts differ, however, regarding whether Aurora may properly deduct overhead charges in calculating Payout.

As Mr. Russell conceded, Aurora "did not consistently include all overhead costs in its earlier payout calculations." PX-55 p. 16. In her testimony, Ms. DeJong confirmed that Aurora had not been including certain overhead expenses under the "LOE" or lease operating expense column on the various spreadsheets she prepared, but she maintained that Aurora had been including some overhead charges as part of the development costs column. Trial Tr. May 13, 2011, 15:23-17:2; 19:21-23. She explained on cross-examination that there are several types of overhead, and conceded that initially Aurora neglected to include a considerable portion in its Payout calculation, including so-called "workover" expenses. When Mr. Russell reviewed the situation, he concluded as an accounting matter that Aurora was entitled to include more overhead than it had previously charged against Payout.

This issue, like the others, involves contract interpretation. The Payout Clause does not expressly refer to overhead by that name, so including it would necessarily require the court to draw an inference that the parties intended to include overhead within the costs incurred by Aurora "for drilling, testing, completing and equipping all wells, constructing and installing all necessary gathering lines, facilities and pipelines, including meters, plus the cost of operating the Antrim Unit prior to Payout." PX-1.

As with other aspects of this dispute, the court turns to the parties' course of performance especially because Frontier has highlighted Aurora's post-litigation change of position on this issue, as personified in Ms. DeJong and expressed in her deposition and trial testimony. On Aurora's end, Ms. DeJong was Ms. Piper's counterpart, the person within the organization charged with calculating Payout and conforming the calculation to the parties' understanding as expressed in the Hudson Agreement. The fact that Ms. DeJong modified her testimony or changed her position after consulting with Mr. Russell raises some doubt, not about Ms. DeJong's veracity, but about the merits of Aurora's post-litigation position on the overhead issue.

Thus, the court finds that Ms. DeJong's view of the proper role of overhead as expressed in the various pre-litigation Payout statements and in her deposition testimony is persuasive evidence of the extent to which overhead may be included in the Payout calculation. When the court combines this course of performance with the default rule of construction in *JJ Fagan* that requires oil and gas leases to be construed in favor of the lessor, the court concludes that Aurora's pre-lawsuit treatment of overhead as included only in development expense shall control. If the court were writing on a clean slate, it might be inclined to adopt Mr. Russell's *post-hoc* interpretation, but the parties' pre-suit performance is more persuasive evidence of their actual intent. This relevant and undisputed conduct, coupled with the rule in *J.J. Fagan, supra*, tips the scale in Frontier's favor on this issue.

G. Profits from Bach Enterprises, Inc. and HPPC.

Striking a recurring theme about Aurora's use of affiliates in developing the Hudson Units, Frontier asks the court to exclude from the Payout calculation the profit component implied in the Bach Enterprises, Inc. ("Bach") and HPPC invoices. Frontier's theory, attributable to Mr. Martindale, finds its best explanation in his testimony:

> We had a circumstance where somewhere during the audit time period, Aurora had purchased Bach Enterprises who had been doing work for them as a third party prior to that. Once they bought them and incorporated them into Aurora, the nature of those costs changed for payout purposes. The payout provision says that when the proceeds of production equal the cost incurred by Aurora or the lessee, then payout occurs and it lists which types of costs.
>
> But the problem with Bach Enterprises is they continued with the -- what would now be an intercompany billing instead of the actual payroll costs and the costs of the trucks. So, those actual costs incurred would be the cost attributable to payout but the -- just the billing from Bach services, the internal billing, would not necessarily represent that.

Trial Tr. Dec. 13, 2010, 135:15-136:5. From this testimony and the subsidiary relationships, Frontier argues that the court should not permit Aurora to deduct the "intercompany profit." To do so, Frontier borrows accounting practices from joint operating agreements where, as a matter of convenience, some joint working interest owners agree to reduce charges by 20% to take into account the profit component included within their market-rate billings. For the same reasons the court gave with respect to the HPPC compression rates, it rejects the argument with respect to Bach and HPPC. While joint venturers may agree to this limitation, and while this limitation may be reasonable, there is no indication in the record that the parties bargained for this reduction. Moreover, a subsidiary is, in the court's view, a third party, a distinct though related entity. In the absence of contractual language or fraud requiring the court to disregard the corporate veil, the court will not re-cast the parties' bargain simply because, in the very different setting of joint operating agreements, some commercial actors have struck that bargain as a matter of convenience and accommodation.

Aurora shall be permitted to deduct the full amount of the Bach and HPPC charges, without regard to the profit component, if any, included therein.

H. 2004 Hudson 34 Leasehold Costs.

The parties appear to have narrowed their dispute about costs Aurora previously deducted and described as "leasehold" and central processing facility costs. This controversy evidently relates to Mr. Martindale's exception for unsupported costs associated with the Hudson 34 Unit. *See* PX-53 (Martindale Report at Exh. A, Exception 7). Mr. Russell responded in his own report as follows:

> . . . [T]he portions of the "'unsupported"' 2004 costs that have been confirmed as HPPC CPF equipment asset costs have been excluded from the Unit payout calculations through NorthStar's October 2008 CPF asset transfer credit. The CPF costs totaled $591,669.91 net ($1,258,872.15 gross).

> My Exhibit DMR-3 revision of Mr. Martindale's Hudson 34 payout schedule and the Updated Payout Statement attached as Exhibit DMR-4 include the credit for the CPF equipment asset costs.

PX-55 at p. 19 of 30. According to Frontier, after Mr. Russell's $1,258,872.15 concession (arising from the accounting adjustments between Aurora and HPPC), the issue has been distilled to $180,277.00 in disputed costs. These remaining disputed costs, according to Mr. Russell, include $7,937.25 in intangible drilling costs and the rest as leasehold costs "incurred . . . in the drilling and development of the Units." *Id.* In its closing brief, Frontier argues that the court should address and resolve this issue using the same analysis the court applies to landman, attorney and title-related costs.

As the court previously explained, the landman and real estate title-related costs fall within the parties' agreement as permissible deductions from Payout, ancillary to drilling but closely-related (and therefore contemplated) in the Payout Clause. For the same reasons, the court will permit Aurora to deduct the balance of the 2004 Hudson 34 Unit expenses in calculating Payout, amounting to $180,277.00.

I. <u>Turnkey Duplicate Charges</u>.

Next, Frontier objects to charges of $256,521.04 made against Payout for cementing services and well site and road construction.[7] It argues that these costs were part of certain fixed-price turnkey contracts and were not properly charged against Payout as separate expenses, citing the turnkey contract language, "Supplying cementing services for all strings of casing." PX-53. Aurora asserts that these charges were not part of the fixed-prices negotiated in the turnkey

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[7] Frontier identified three separate categories of overpayments which it alleges should have been covered under "turnkey" contracts: $18,781.86 and $20,115.97 to BJ Services Company for cementing that Arrow Energy Services, Inc. was supposed to provide, and $217,623.21 to various vendors for constructing well-sites and access roads.

contracts and were properly included in the Payout calculation as "costs incurred by lessee for drilling."

At trial, Ms. Abbott testified that when the invoices for these services came in to Aurora, they were compared to the turnkey contracts to determine whether they were within the scope of the respective agreements. Trial Tr. May 12, 2011, 40:24-41:7. She confirmed that all of the costs of these services fell outside of the turnkey contract price and were properly included in Payout. Frontier, on the other hand, offered no evidence or testimony, other than Mr. Martindale's exception to these charges. The court credits Ms. Abbott's report of her review of the turnkey contracts and the challenged invoices.

Consequently, the court finds that Frontier has failed to meet its burden of proof regarding the charges against Payout that it claims were within the turnkey contracts.

J. Duplicate Casing Charges.

Frontier took exception to several charges for metal casings to two wells on the Hudson NE unit, alleging that these charges were duplicates. Trial Tr. Dec. 13, 2010, 135:5-8. At trial, Mr. Russell explained that what appeared to be a duplicate charge was really a description error on the face of the invoice. Trial Tr. May 19, 2011, 77:3-6; PX-53, Exh. A, Report of David M. Russell, p. 5-6, DMR-3R, Exh. C, Schedule 2D. Testimony from John Hunter established that drilling in the Antrim Shale involves "spudding" followed by placing a "conductor" pipe into the hole. Aurora then inserts the "surface casing" -- a smaller diameter pipe -- within the conductor and pours concrete into it to fill the gap and form a "concrete sheath" to protect the casing. The court infers that using two casings facilitates the concretization of the well, while preserving space through which the natural gas and water are removed from the ground. Thus, two casings of different sizes are required for each well.

According to the invoices, two of the same size casings were inserted into one well and two of a different size were put into the other well. In fact, according to the supporting documents to the invoice, one pipe of each size went to each well because the smaller casing fits inside the larger one. Therefore, each well needed one of each size, as Mr. Hunter explained, which in reality is what they received. Trial Tr. May 19, 2011, 76:21-24.

Again, other than Mr. Martindale's exception to these charges, Frontier showed no evidence to dispute that this was simply an invoice error and that Aurora's vendor correctly delivered the properly sized casings to each well. Therefore, Frontier did not meet its burden as to this issue.

K. <u>Development Adjustment for Hudson 34</u>.

This aspect of the parties' dispute involves corrections or additions that Aurora made to account for pre-2005 development costs associated with the Hudson 34 unit. In the course of this litigation, Aurora provided accounting information for Mr. Martindale's onsite audit, representing on several occasions and in several spreadsheets that Aurora had calculated gross development costs allocable to the Hudson 34 unit through June 2005 in the amount of $4.3 million. In preparing his expert report for this litigation, Mr. Martindale relied on this figure to determine net development costs for this unit (based on Frontier's ownership percentage), and ultimately to calculate Payout for this particular unit.

Closer to trial, while reviewing the spreadsheet that Ms. DeJong prepared, however, Mr. Russell became concerned that the $4.3 million figure was not correct. What caught his attention was that the net development figure of $3.2 million was patently larger than roughly 47% of the $4.3 million gross figure, based upon what the court characterized during the trial as his "back-of-the envelope, eyeball calculation." Mr. Russell explained how he discovered the discrepancy between the $6.7 million gross figure upon which Aurora now relies and the $4.3 million figure that Frontier advocates:

> Q. Okay, how do you know 6.7 million is the correct number?
>
> A. Again, I had asked Ms. DeJong to identify all of the support documentation that supported the net number of 3.2 [million dollars]. Originally, Mr. Martindale hadn't been provided anything but a summary of the net number, the 3.2 million. So when I saw 4.3 as a gross versus 3.2 and I knew that the entered ownership percentage was supposed to be forty-seven percent, 3.2 is way more than forty-seven percent of 4.3. So I knew there was some kind of a disconnect there. So what I did was I asked Ms. DeJong again to go back and find the documentation that showed what the actual gross numbers should be. There had been a question about whether or not it was impacted by Aurora sharing more than forty-seven percent, but this disconnect seemed to be too big to me to explain that.

Trial Tr. May 19, 2011, 89:6-19. In other words, 47 % of $4,353,577.62 was considerably lower than Ms. DeJong's net figure of $3,222,217.01.

Upon further investigation at Mr. Russell's request, Ms. DeJong credibly explained that she incorrectly inputted $4,353,577.62 in the pre-2005 gross development expense column on the spreadsheet (PX-62B) that she shared with Mr. Martindale. Trial Tr. December 13, 2010, 34:7-37:17; Trial Tr. May 12, 2011, 198:8-202:2; Trial Tr. May 19, 2011, 86:14-93:21; *compare* PX-62B with DX-200. In March, 2010, Aurora provided an updated payout statement reflecting gross development costs of $6,746,498.64, a figure she confirmed by examining the voluminous joint interest billings from Aurora's former partner, OIL, for the relevant period. At trial, Mr. Martindale refused to accept this figure, presumably based on his theory that audit numbers must be fixed as of a specified point in time, and not revised, in order to avoid a "moving target." Trial Tr. June 6, 2011, 35:13-36:15.

The truth-seeking function of a trial, however, does not permit the court to wear blinders. It plainly appears, based upon the credible testimony of Mr. Russell and Ms. DeJong, that Ms. DeJong made a clerical error by inputting the $4.3 million figure in a cell on a spreadsheet where she should have inputted $6.7 million, based upon the OIL joint billing statements. The court will not enshrine this error affecting substantial rights based on nothing more than "audit protocol." Frontier had the updated information several months before trial. The evidence on this point is "reflective of no more than a mistake on defendant's part and thus . . . ultimately irrelevant," in the absence of evidence to support an estoppel or similar relief. *Schroeder v. Terra Energy, Ltd.*, 565 N.W.2d 887, 896 (Mich. App. 1997).

Finally, Frontier also complains, in its closing brief, that "Aurora cannot be allowed to increase the gross development costs by $2.4 million by pointing to a stack of papers which do not even represent the actual invoices for these new costs." *See* Frontier Br. at 82. This derogatory summary of the record ignores the fact that Frontier had the burden of proof. In addition, although the joint billing statements are not the actual invoices, the court has no reason to doubt Ms. DeJong's testimony that they represent the costs of developing the Hudson 34 unit.

In short, the court is satisfied that Aurora properly relied upon the gross development costs of $6,746,498.64, or at least that Frontier has not met its burden of showing that the number is incorrect.

VIII. POST-PAYOUT ROYALTY CALCULATION

The parties agree that after Payout, Frontier is entitled to an escalating royalty of between 15-50%, depending upon the price per MMBTU that Aurora obtains for its gas. They disagree, however, regarding Frontier's appropriate share of PPCs after Payout.

Frontier asks the court to permit it to receive the amount of revenue associated with the higher, post-Payout royalty rate, but to fix Frontier's share of PPCs at the lower 15% rate; Aurora, in contrast, contends that Frontier must bear its share of post-Payout production costs commensurate with its escalating royalty rate.

As Aurora's expert explained, after Payout, Aurora must pay Frontier at a "blended rate" which recognizes that the rate on gas sold at prices at or below $2.50 per MMBTU remains constant at 15%, the rate on gas sold at prices between $2.50 and $3.50 per MMBTU is 25%, and likewise, 50% for gas sold for more than $3.50. Because a different rate applies at each pricing tier, it makes sense to think of the royalty rate, in practice, as blended.

Before Payout, the parties evidently agree that Frontier's share of PPCs depends upon, or is "a function of," its pre-Payout 15% royalty rate. Dale Nielson agreed that, in general, a lessor's royalty rate determines its share of PPCs. Trial Tr. Dec. 9, 2010, 114:2-115:1. Indeed, Frontier has borne 15% of the PPCs in the pre-Payout era, presumably for this reason. After Payout, however, Frontier asks the court to fix its share of the PPCs at 15%, even though it asks for an escalating royalty. Its expert attempted to justify the position as follows:

> . . . [P]ost-production costs are based on volume and allocated accordingly, like we talked about at the beginning of my testimony. They are not allocated in the same way that sales are allocated. That's number one. So they're volume based.
>
> Well, we already have a distinction of ownership of the volumes under this lease. We have . . . 15 percent Frontier and 85 percent Aurora. And Mr. Russell and I agree on this following point, and that is this tiered royalty does not affect volume; it affects the increased value of that same volume of gas sold.
>
> And so when you look, as we obviously had the opportunity to do in hindsight, those post-production costs have already been allocated to the parties based on volume. They've paid their share, Aurora by paying them in

> the first place and Frontier by having them deducted from their royalty check that was paid to them. That's already taken care of, and that's a volumetric assessment and allocation.

Trial Tr. Dec. 14, 2010, 101:15-102:9. Aurora's expert, Mr. Russell, disagrees.

Mr. Russell originally argued that Frontier should bear its share of PPCs at the highest of the tiered rates, but after considering Mr. Martindale's criticism, he modified his position to advocate for a blended rate on both the revenue and PPC sides of the royalty equation. Trial Tr. May 19, 2011, 155:1-157:3. He explained that, according to the industry, deductions are always taken in the same proportion as the royalty rate:

> If the royalty fraction is fifteen percent and that's all it says, the deductions are taken at fifteen percent. If the royalty fraction is twenty-five percent, you always take deductions at twenty-five percent.

Id. 156:13-17.

The court favors Aurora's position for several reasons, first of which is the language of the Hudson Agreement itself. The language that the parties specifically bargained for says that the royalty after Payout "shall be a function" of the price of gas, as described in their enumerated tiers. Frontier's "royalty" -- the payment it receives each month on account of its interest in a particular well -- depends upon, or "is a function of," the royalty rate and the PPCs. Prior to Payout, Frontier evidently bore 15% of the PPC, corresponding precisely with its pre-Payout royalty rate. The lease does not specify the 15% portion of the PPCs pre-Payout any more or less than it specifies the post-Payout portion of PPCs that Frontier bears, yet the parties agreeably inferred a 15% rate for PPCs pre-Payout.

After Payout, the royalty remains dependent upon, *inter alia*, the PPCs, but now the royalty is also a "function" of the price for gas that Aurora sells. The word "function" connotes a relationship between variables: after Payout, the price of gas. But, even before Payout, from the parties' course of performance, it would appear that the share of the PPCs was also a function of the royalty rate -- 15%. The court sees nothing in the language of the Hudson Agreement to modify that aspect of the equation or, in the parties' words, the "function" of the royalty rate, whether fixed (pre-Payout) or escalating (post-Payout). The direct correspondence between the royalty rate and the lessors' share of the PPCs finds support in the industry custom, as testimony from Dale Nielson, David Russell, and Patrick Martindale confirms. Trial Tr. Dec. 9, 2010, 114:2-115:1 (Nielson); Trial Tr. May 19, 2011, 156:5-158:14 (Russell); Trial Tr. Dec. 14, 2010, 62:20-63:23 (Martindale).

Mr. Martindale assumes that the 15% represents a division based upon volume rather than royalty rate, even though the pre-Payout allocation of PPCs is the same as the pre-Payout royalty rate. Given other testimony, however, the court does not believe this obvious correlation between the royalty rate and the pre-Payout share of PPCs is a mere coincidence. Rather, the share of the PPCs is indeed a "function" of the royalty rate, before and after Payout.

Because the text of the Hudson Agreement and the course of performance (at this point pre-Payout) confirms the relationship between the royalty rate and Frontier's share of the PPCs, the court has no occasion to resort to the default rule of contract interpretation described in *J.J. Fagan, supra,* which might otherwise direct the court to construe the agreement in favor of Frontier as lessor. Aurora has the more compelling interpretation based upon the evidence adduced at trial, and the evidence does not preponderate in favor of Mr. Martindale's supposed volumetric premise.

IX. CONCLUSION AND ORDER

This Opinion resolves discrete issues of interpretation, but under the circumstances falls short of decreeing a specific amount of unpaid royalties or declaring that any particular unit has reached Payout. Instead, as the court and counsel accurately predicted during trial, it appears that the parties will have to meet and confer, with the help of their experts, to make new calculations based on the direction the court has endeavored to provide in this Opinion. The issues the court has resolved are complex, and given the inventiveness of counsel, it seems likely that the Opinion will generate new questions, but with luck fewer than those the court regards as resolved. The court encourages counsel to focus their considerable talents and attention on negotiating a resolution of the remaining issues, rather than searching the Opinion for new ones.

Regardless, it makes sense to give the parties time to digest this Opinion, caucus with their experts and confer with each other, before the court calls them back to the courthouse to discuss the next steps in the case.

NOW, THERFORE, IT IS HEREBY ORDERED that the parties shall appear at a status conference to be held on January 25, 2012 at 1:30 p.m.to consider further proceedings consistent with this Opinion including, but not limited to, additional hearings if indicated, the form of a final judgment if possible, or a deadline for Aurora to propose a cure of lease defaults (if Aurora intends to assume the Hudson Agreement under 11 U.S.C. § 365), and a deadline to assume or reject the Hudson Agreement and the Corwith Agreement.

IT IS FURTHER ORDERED that the Clerk shall serve a copy of this Opinion pursuant to FED. R. CIV. P. 9022 and LBR 5005-4 upon Timothy A. Fusco, Esq., D. Andrew Portinga, Esq., Charles N. Ash, Jr., Esq., and David R. Whitfield, Esq.

END OF ORDER

IT IS SO ORDERED.

Scott W. Dales
United States Bankruptcy Judge

Dated: October 28, 2011