<table>
<tr><td>DISTRICT COURT, LA PLATA COUNTY, COLORADO

Court address: 1060 E. 2nd Ave., Durango, CO 81301

Phone Number : (970) 247-2304
Fax: (970) 259-0258

RICHARD PARRY, et al.
Plaintiff(s)

v.

AMOCO PRODUCTION CO., a Delaware Corporation, n/k/a BP AMERICA PRODUCTION COMPANY
Defendant(s)</td><td>COURT USE ONLY</td></tr>
<tr><td>David L. Dickinson
District Court Judge
1060 E. 2nd Ave.
Durango, CO 81302</td><td>Case Number: 94CV105

Division: II Courtroom:</td></tr>
</table>

ORDER ON MARKETABILITY AND REASONABLENESS OF COSTS

Named Plaintiffs and the members of Plaintiff subclasses consist of royalty and overriding royalty owners[1] who received royalty payments from Amoco for production of gas

[1] A royalty owner is typically the lessor under an oil and gas lease, or an assignee of the lessor. An overriding royalty is a royalty carved out of the working interest of the lessee, typically when the lease is assigned by the original lessee or its successor in interest. As the

from June 1, 1991, and who acquired their interest prior to October 31, 2001 (see Order of May 21, 2002). Plaintiffs bring this action against Defendant ("Amoco"), alleging that Amoco wrongfully deducted gathering, treating and compression costs (in the interest of brevity the Court will refer to these costs hereinafter as "GTC costs") from their royalty payments. Amoco contends that GTC costs were properly deducted pursuant to the lease language in the royalty instruments and/or that the gas is marketable at the well head, arguing that the history of gas sales in the San Juan Basin, together with existing well head sales, show that gas is marketable at the well.

The primary issue before this Court is whether the gas is marketable, both in condition and location, at the well prior to GTC, or is marketable only after these processes have been completed and the gas is ready to enter the interstate pipeline.

Plaintiffs originally filed this action in 1994, and in August of 2002, a bench trial was held before this Court on the issues of marketability and reasonable costs (the damages phase of the action was bifurcated). Having considered the twenty-nine volumes of trial and pretrial

---

distinction between royalty and overriding royalty interests is not significant for purposes of this Order, the Court will, for brevity, occasionally refer to all such interests as lessors.

pleadings, fifteen days of testimony, deposition designations, expert reports, thirty volumes of exhibits offered, and arguments of counsel,[2] and being advised in the premises, the Court concludes that the gas in question is marketable only at the inlet to the interstate transmission pipeline (i.e., the tailgate of the processing plant), after completion of all GTC, and that Amoco's costs, with two exceptions, are reasonable and may be assessed on a "postage stamp" basis.

I. FACTUAL OVERVIEW AND CASE HISTORY

The gas wells at issue are located within what is known as the San Juan Basin, which extends from northwest New Mexico to southwest Colorado. The San Juan Basin is located in an area where there is no significant local consumptive demand for natural gas. Involved in this action are some 600 wells in which Amoco owns a working interest and which are located in La Plata or Archuleta Counties in Colorado. Both conventional and coal seam gas (also known as

---

[2] Citations to this record will be as Tr., followed by the date of the testimony and name of the witness, or to the witness and the date. Plaintiffs' exhibits will be cited as P.E. (or PE) ___; Amoco's, as Ex. ___.

"coal bed gas," "coal bed methane," or "CBM")[3] are extracted from these wells, although the majority of the gas at issue in this case is coal seam gas (see below for a discussion of the development of coal seam gas).

Plaintiffs are holders of royalty and overriding royalty interests in these gas wells. The Court considered the large number of royalty owners, commonality of their interests, typicality of the representative plaintiffs, and compelling reasons of judicial economy and certified this action as a class action by this Court's Order of September 6, 1996 (Hon. Timothy A. Patalan, Judge). The lease instruments that define the contractual relationships between the royalty owners and Amoco fall into three main categories, and the plaintiffs have been divided into three main subclasses, as discussed in more detail *infra*. This action was commenced after these royalty owners experienced deductions in their royalty payments for services which they now claim were inappropriately deducted.

II. HISTORICAL BACKGROUND

A. San Juan Basin Pipeline

---

[3] Wells producing CBM were often referred to as "coal degas wells," because the production process involves degasification of the coal in which the gas is found.

Although the presence of natural gas in the San Juan Basin was known in the 1920's, no development occurred, because there was no market for the gas in the Basin. Even today, there is virtually no commercial demand for gas in the Basin. Tr. 8-15-03 (White). In the early 1950's the El Paso Natural Gas Company ("El Paso") built an interstate pipeline linking the San Juan Basin with California, and development of conventional natural gas began. A few years later, the Northwest Pipeline Co. ("Northwest") constructed a pipeline connecting the San Juan Basin with the Pacific Northwest region. The interstate pipelines built by El Paso and Northwest spurred significant activity by exploration and production companies of conventional gas, including Amoco's predecessor (Stanolind Oil Co.) and other companies whose leases Amoco later acquired. Tr. 8/21/02 (Jack); Tr. 8/20/02 (Mueller).

In addition to their long-haul interstate pipelines, El Paso and Northwest also built, owned, and operated field transportation systems for conventional gas in the San Juan Basin. These systems connected individual wells with the various Central Points of Delivery ("CPD's"). The field transportation systems included compressor stations, dehydrators and plants for removal of natural gas liquids and delivered the processed gas to the inlet for the interstate transmission pipelines. Exs. 3024, 3042; Tr. 8/21/02 (Jack and Mummery)

From the early 1950's until the 1980's or early 1990's, gas producers in the San Juan Basin sold almost all of their conventional gas at the well head, and later coal seam gas, to the interstate or intrastate pipeline companies. Tr. 8/20/02 (Mueller); Tr. 8/19/02 (Mitchell); Tr. 8/21/02 (Jack); Exs. 2580, 3012.

B. Federal Regulation and "Open Access"

Beginning in 1954, oil and gas prices, as well as pipeline transmission companies, began to be regulated first in interstate commerce, and later in intrastate commerce. The federal government promulgated rules through the Federal Power Commission ("FPC"), and later the Federal Energy Regulatory Commission ("FERC"), which formed a pervasive regulatory scheme for control of well head prices, transportation charges, and charges to end users.

Between 1985 and 1992, the character of the natural gas industry underwent fundamental changes due to reform of these natural gas regulations, including deregulation of well head prices and transmission pipelines. Under open access, interstate pipeline companies were required to sell space in their pipelines to gas shippers, and thereby became transporters instead of purchasers of gas. The services previously provided by pipeline transmission companies (gathering, treatment, compression, and transportation) were, in industry parlance, "unbundled."

Interstate pipeline companies switched from being "merchant" companies that bought gas at the well and re-sold it downstream to "common carrier" companies much like railroads. Open access enabled gas producers to sell their gas downstream from the well. Mueller; Exs. 3007, 3008. This period of regulatory reform in the natural gas industry coincided with large-scale development of coal seam gas in the San Juan Basin. Tr. 8/20/02 (Mueller); Tr. 8/19/02 (Mitchell); Tr. 8/21/02 (Jack). For a detailed discussion of this regulatory reform, see *Associated Gas Distributors v. F.E.R.C.*, 824 F.2d 981 (C.A.D.C., 1987). For a discussion of the effects of deregulation, as well as repeal of depletion allowances, on natural gas producers, and the royalty litigation which resulted, see Anderson II (complete citation *infra*), at 553-571, theorizing that the net effect of open access and repeal of the depletion allowance was to give producers an incentive to "push profits downstream away from the well head and to push costs upstream toward the well head," *Id.*, at 554.

During the transition to open access, interstate pipeline companies often negotiated to be released from their contracts with oil and gas companies, as the contracts were no longer economically beneficial or even feasible. Once released, these producers were able to sell gas to alternative buyers at the well or at a downstream location. Tr. 8/20/02 (Mueller). Eventually, the interstate pipeline companies substantially ceased their "merchant" functions and terminated their long-term traditional well head sales contracts with San Juan Basin producers, including Amoco. Tr. 8/20/02 (Mueller); Ex. 2807. Amoco, along with the other major oil companies, began marketing gas downstream and moving towards vertical integration to access premium markets. This gas had previously been sold at the well head. Tr. 8/21/02 (Mueller, Jack); Tr. 8/27/02 (Parker).

Open access also resulted in interstate pipeline companies "spinning down" the GTC facilities that they had built in the San Juan Basin to affiliates or independent companies, thereby creating opportunities for others to purchase or build and operate the GTC facilities themselves. Tr. 8-21-02 (Jack); 8-19-02 (Kelly); Ex. 3056.

After deregulation, some major gas producers in the San Juan Basin, including Amoco, chose to become "vertically integrated," providing all production and GTC services before sale of the gas at the plant tailgate or further downstream. In the New Mexico portion of the San Juan Basin and in portions of Colorado Amoco sold its gas at the well to Amoco Energy Trading Corporation ("AETC"), which contracted with third parties to gather, compress, dehydrate and process or treat the gas. AETC is a wholly owned subsidiary, formed to market Amoco's gas as well as an unknown quantity of gas from other companies. AETC then resold the gas at downstream locations. Also in Colorado, Amoco built the Florida System (described *infra* at p. 9), and AETC was charged a fee by Amoco for gas purchased by AETC at the well and moved through the Florida System. AETC then typically resold the gas downstream, either at the plant tailgate or to end users such as major industrial users or local distribution companies ("LDCs").

C. Development of Coal Seam Gas in the San Juan Basin

In the late 1980's, due to the incentive provided by a federal tax credit, gas producers began large-scale development of coal seam gas in the San Juan Basin. Under the federal tax credit, both working interest owners and royalty/overriding royalty interest owners were allowed a credit against federal income tax based on sales of CBM. Tr. 8/21/02 (Jack); Tr. 8/22/02 (Smith). As new CBM wells were drilled and existing conventional wells were re-completed to access the coal seam gas,[4] CBM wells were at first connected to the existing field pipeline systems owned by interstate pipeline companies, and the producers sold the gas at the well under

---

[4] Wells producing conventional gas usually passed through the Fruitland formation, which is the source of CBM. By recompleting the well, it could produce CBM gas from the Fruitland formation as well. In some cases, the conventional and CBM gas was commingled; in others, each was separately produced. Tr. 8-20-02 (Mueller).

existing traditional well head sales contracts. These contracts were still regulated by FERC. (See below for a discussion of why construction of an entirely new gathering and treatment system for CBM wells eventually became necessary.)

III. PRESENT OPERATIONS

A. Natural Gas Properties and Extraction

Normally the natural gas extracted consists mainly of methane, but other substances may be extracted along with the methane. For conventional gas wells, these additional substances include water vapor, "diluent" (non-combustible) gases, such as carbon dioxide (CO_2), hydrogen disulfide (H_2S), nitrogen, and natural gas liquids ("NGLs") such as butane and propane. For CBM wells, the additional substances include only water and diluent gases. At each well, any liquid water produced is removed by means of mechanical water separators. After the water is separated, the gas is moved to a measurement or "metering" station, also called a “custody transfer meter,” by means of a short pipeline called a "flow line". The gas moves away from the metering stations near the wells in various field pipeline or "gathering" systems. Most of the gas then moves to CPD's where it is compressed and, in most cases, water vapor is removed.

After leaving the CPD’s, conventional gas typically is required to have the NGLs removed and the diluent gases (H_2S and, in some cases, CO_2) reduced before it will be allowed to enter the interstate pipelines. Coal seam gas typically requires reduction in the concentration of CO_2, a non-combustible diluent gas, to the specification required by the interstate pipelines, then dehydration (the amine process used to remove CO_2 rehydrates the gas), then compression to interstate pipeline pressure. Conventional gas also contains CO_2 but usually in concentrations below the specifications of interstate pipelines. The interstate pipeline companies' specifications are imposed for profit, safety and operating reasons. Tr. 8-23-02 to 8-26-02 (Blauer); Exs. 2622 (Blauer) and 3005, 3006 (Mueller)

B. The Florida River System and other San Juan Basin GTC Systems

Most of the gas at issue in this case flows through the Florida River Field Transportation System ("the Florida System"), built by Amoco expressly to process CBM. The Florida System consists of field pipelines for both gas and the liquid or "free" water that is removed at the well sites, a water disposal system, CPD's, gas compressors, gas dehydrators, and the Florida River Plant. The Florida River Plant contains amine trains to remove CO_2, compressors to compress the gas to transmission pipeline pressure (approximately 800 p.s.i.), and dehydrators to remove the water added by the amine trains. All of these activities are necessary to bring the gas to pipeline specifications. Amoco has owned and operated the Florida System since construction began approximately thirteen years ago. At various times since then, Amoco has added to the system as the need arose for additional capacity.

Amoco bears all of the costs of the mechanical water separators, flow lines, metering stations, and well head compressors located at a small number of Amoco's wells. Amoco also bears all costs of the water disposal part of the Florida System. Those costs are not at issue.

The Florida River Plant is located near major interstate gas transmission pipelines owned and operated by El Paso, Northwest (a division of the Williams Companies), and Transwestern Pipeline Co. Gas is delivered into one or more of these interstate pipelines after it moves through the Florida River Plant.

Some of the gas from Amoco's wells moves away from the wells in field gathering systems owned and operated by third parties, including Red Cedar Gas Gathering Co., El Paso Field Services Co., and Williams Field Services Co. These third-party systems, like the Florida System, include field pipelines, CPD's, compressors, dehydrators, and plants. Amoco and the third parties have entered into field services contracts through which Amoco makes payments to the third parties, in the form of both money and gas, in exchange for the use of third party field transportation systems. Tr. 8/22/02 (Kyle); Exs. 2273-2287.

Similarly, some third parties purchase field services from Amoco. Pursuant to field service contracts, they pay Amoco for services provided to their gas in the Florida System. Tr. 8/22/02 (Kyle); Tr. 8/20/02 (Mueller); Exs. 2288-2294, 2539. Some gas produced by Amoco in this case moves between the well and an interstate pipeline using a combination of the Florida System and a system owned by a third party.

Under Amoco's Third Party Purchase Program, Amoco or AETC, Amoco's wholly owned subsidiary, transacts with parties who own working interests in wells operated by Amoco. Amoco or AETC either buys the third party's gas at the well or transports the third party working interest owner's gas in the Florida System for a fee. Tr. 8-20-02 (Mueller); Tr. 8-28-02 (Kalt); Exs. 3014, 2539.

IV. SPECIFIC FACTUAL ISSUES

A. Royalty Instruments

The royalty instruments at issue in this action have been categorized into three subcategories pursuant to the Court's Order of September 6, 1996, which the Court hereby incorporates by this reference. The categories were grouped according to their specific provisions in the leases relative to the payment of royalties and allocation of costs. There have been additional orders on categorization of royalty instruments that did not vary the subclasses themselves, but only categorized additional instruments. Additional motions were filed requesting the Court to modify the categories, which the Court ultimately denied, and therefore the subclasses remain as originally defined by Judge Patalan. See Order on Modifications to Subclasses entered June 26, 2002, as well as Orders of May 17, 2002, as amended, June 13, 2002. The Court reaffirms the findings of those Orders; in particular, the finding in the May 17, 2002 Order, as amended June 13, 2002, that leases containing "at the well" or "at the mouth of the well" language but containing no other language allocating post-production costs,[5] are silent as to allocation of costs, *Rogers v. Westerman Farm Co.*, 29 P.3d 887 (Colo. 2000), hereinafter "*Rogers*," at 897.

B. June 17, 1991 letter

From the outset, Amoco expected to be able to require lessors to bear a proportionate share of GTC costs. See P.E. 65 ("All post production costs are deductible from the private

---

[5] Throughout this Order, the Court will use "post-production" costs in the sense discussed in the May 17, 2002 Order, as amended June 13, 2002, at p. 3.

royalty owner unless the lease agreement specifically disallows them.").[6] The initial conflict between royalty owners and Amoco began when royalty owners received a letter dated June 17, 1991(P.E. 17), in which Amoco informed leaseholders that beginning that month, their royalty check would reflect deductions for "post production" costs. Amoco stated,

> Beginning with your June, 1991 settlement, your check will reflect your share of post production costs associated with processing your gas through the Amoco operated Florida River Compressor Facility. Processing your gas through the components of compression, gathering and treating at the Florida River Facility is necessary to make your gas meet pipeline quality specifications and to move your gas to market.

V. COMMERCIAL REALITIES OF THE SAN JUAN BASIN

A. Production and Marketing of Gas

Amoco stated to its royalty owners that "the gathering fee is primarily for compression and dehydration of the gas to make it marketable" (See Plaintiffs' Exhibit 69 at JM000797) and thus specifically acknowledged that their ability to market gas depends upon that gas being able

---

[6] In other words, Amoco expected Colorado to adopt the so-called "severance rule." Amoco made a "blanket assumption" that post-production costs were deductible without review of lease agreements, P.E. 66. The GTC facilities were designed to generate revenue by charging a fee to the leases, P.E. 58, and Amoco began accounting for the Florida River and Bayfield Gas Gathering Systems as an independent profit center in April 1991, P.E. 61.

to enter the transmission pipeline(s) leading out of the San Juan Basin.

Amoco controls most of the acreage from which CBM gas is being extracted in southern Colorado. Tr. 8/13/02 (Graham).[7] When Amoco began developing the CBM reserves in the 1980's, the interstate pipeline "takeaway capacity" was not adequate to handle such additional production, Tr. 8/14/02 (White), and the conventional gas GTC facilities had insufficient capacity to handle the additional production and could not treat CBM efficiently because CBM did not need NGL removal but did need treatment to lower CO_2 content. Tr. 8-19-02 (Kelly); 8-21-02, (Jack). To help address this problem, El Paso extended its interstate pipeline within 1 ½ miles of the future site of Amoco's Florida River Treatment Plant. Tr. 8/13/02 (Graham). Until additional capacity was added, large volumes of gas could not be processed, and many wells were "shut-in" or production from them was curtailed. Tr. 8/14/02 (Graham). Where possible, Amoco chose to curtail the production of conventional rather than CBM gas in order to

---

[7] One of the factors which distinguishes this case from other cases, such as *Rogers, Garman v. Conoco*, 886 P.2d 652 (Colo. 1994), hereinafter "*Garman*," and the *Savage* case in Garfield County (discussed *infra*) is that Amoco does not produce all of the gas in the San Juan Basin. While Amoco conducted an aggressive program of lease acquisition, some working interest owners and small independent producers elected to retain their interests. Also, other "majors" have both conventional and CBM production interests. Thus, in addition to Amoco,

maximize its federal tax credits. Tr. 8/13/02 (Graham). Amoco could not market all of the CBM gas it was planning to produce in southern Colorado without expansion of the takeaway capacity nor without construction of separate GTC facilities to meet the different requirements for CBM gas. Tr. 8/14/02 (White)

Before construction of the Florida System, production of CBM gas was limited by pipeline specifications; even to produce what it did, Amoco asked for (and received) waivers on CO_2 content. Had deregulation not occurred, El Paso or Northwest would have constructed GTC facilities to Amoco's wells as they had traditionally done, and Amoco would have sold gas at the well head. Tr. 8/21/02, Mueller.

All parties agree that Amoco developed superior technology and took considerable risk in the development of CBM and that lessors benefited from increased production. Tr 8/13/02 (Bell).

Amoco initially sought proposals from third parties for construction of GTC facilities in Colorado but eventually elected to construct the gathering and treatment facilities "required to market production from our core development area." (P.E. 45 at AMC000560). When obtaining a local land use permit for these facilities, including the Florida River Treatment Plant, Amoco

---

gas is produced by both major oil companies and small independent producers.

told La Plata County officials that, "[i]n order for the coal seam gas to meet market quality, it must be treated to remove excess carbon dioxide and the gas has to be compressed to transmission pipeline system pressures."(Plaintiffs' Exs. 410, 413, 414, 77; Kelley Depo. 7-10-02, p. 65, l.12 to p.67, l.16; p. 100, 1.5 to p. 104, 1.17).

As shown on Exhibit A to Plaintiff's proposed findings of fact, the gas involved in this case enters one of three interstate pipelines (Northwest Pipeline, Transwestern Pipeline or El Paso Natural Gas). Tr. 8-13-02 (Bell). These pipelines have tariffs and delivery specifications that require Amoco to deliver the gas at the pressure necessary to access the pipeline and in a condition that meets the following requirements: (1) not more than 7 pounds of water per million cubic feet; (2) not more than 2 or 3 percent CO_2; and (3) not more than 3 to 5 percent total inerts. Tr. 8-13-02 (Bell); Tr. 8-15-02 (White); Plaintiffs' Ex. 90 at AM02904; Plaintiffs' Ex 91 at PL02060, PL02062; Plaintiffs' Ex. 92 at PL02063, PL02068.

The facilities depicted on Exhibit A, including the treatment plants, enable Amoco's gas to meet these specifications and thereby gain access to the pipelines that transport the gas to out-of-basin markets. Mummery Depo., 6-18-99, pp. 92-93, p. 117, ll. 12-14; 10-26-00, p.71, l.25 to p.72, l.4; Tr. 8/22/02 (Mummery); Plaintiffs' Ex. 44 at ADU002007; Plaintiffs' Ex. 45. "The treatment of the gas and compression of the gas was to bring the gas to the quality and pressure required to get into the main line systems, and from there the main line system would move the gas to either markets or that would be a market itself." Jensen Depo., 12/4/01, p. 284, ll. 7-12 emphasis added.

B. Amoco's Disposition of CBM gas.

Amoco presently produces approximately 275 MMCF/day of CBM gas in Colorado. Tr. 8-13-02 (Graham). Plaintiffs' Exhibit 601 describes what happens to that gas.

As shown by the row labeled "AETC" on Plaintiffs' Exhibit 601, over 90% of Amoco's CBM gas was sold by its affiliate, AETC, by delivery to the interstate pipeline. The Court notes that Amoco asserted in pre-trial motions that payment of royalties based upon well head sales to AETC satisfied Amoco's obligation under the "at the well" language of the leases. The Court rejected that assertion in its August 2, 2002 Order relative to various pre-trial motions, as this contention was squarely rejected in *Rogers* . However, the Court in its August 2, 2002 Order allowed Amoco to admit at trial evidence of sales to AETC relative to the issue of marketability of gas.

The other 10% breaks down into 6% field uses and 4% local sales.[8]

VI. CONCLUSIONS OF LAW

Central to the Court's decision in this case is the Colorado Supreme Court's opinion in *Rogers*, as well as its decision in *Garman*.

The Court has also considered the writings of Owen L. Anderson, Eugene Kuntz Professor of Oil, Gas & Natural Resources at the University of Oklahoma College of Law. Anderson is cited with partial approval several times in *Rogers*, though the *Rogers* court declines to adopt his views *in toto*, *Id.*, at 898, 899, 901, 904-06. The writings involved are a series of articles, beginning with *Calculating Royalty: "Cost" Subsequent to Production– "Figures Don't Lie, But . . ."* 33 Washburn L. J. 591 (1994) ("Anderson I"); *Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 1 Why All the Fuss? What Does History Reveal?*, 37 Nat. Resources J. 547 (1997) ("Anderson II");

---

[8] "Free gas" provided from "gas taps" accounted for 0.02% of the total. "Field uses" for compression accounted for 6.3% of the total. "Post-1-1/90 Contract Sales" accounted for 0.2% of the total. The "Duke Sales" accounted for 0.23% of the total. The "Greeley Gas Sale" accounted for 0.002% of the total. The "Vastar Sale" accounted for 0.3162% of the total. The "POI Sale (CO Portion only)" accounted for 0.1478% of the total. The "La Plata Airport Sale" accounted for 0.0061% of the total. The "PSCo CO Corridor" accounted for 2.34% of the total.

Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, or Realistically? Part 2 Should Courts Contemplate the Forest or Dissect Each Tree?, 37 Nat. Resources J. 611 (1997) ("Anderson III")[9]; *Royalty Valuation: Calculating Freight in a Marketable-Product Jurisdiction*, 20 Energy & Min. L. Inst. 10-1 (1999) ("Anderson IV"); and *2001: A Royalty Odyssey*, 53rd Annual Institute for Oil and Gas Law, 2002 ("Anderson V"). Anderson I through IV are pre-*Rogers*; Anderson V, post-*Rogers*. Amoco notes that Anderson V is critical of the *Rogers* analysis and suggests that Anderson's criticism, since *Rogers* is based upon Anderson in part, allows this Court to revisit the issue of the "severance" rule.

While Amoco is correct in saying that Anderson is critical of *Rogers*, Anderson V, at pp. 13-22, 24-26, the Court notes that this criticism is directed in large part to the "location" portion of the marketability test,[10] *Id.*, in particular, the *Rogers* court's refusal to distinguish between

---

The "Williams Contract" accounted for 0.025% of the total.

9 Anderson II and III are cited in *Rogers* as Anderson, Part 1 and Part 2.

10 Anderson also criticizes the opinion for basing the first marketable condition rule on the implied covenant rather than on the plain meaning of "production" and terms of common royalty clauses when construed as a whole. *Id.*, at 17.

long-distance transportation and gathering, Anderson V, at 16-17. Long distance transportation is not involved in this case, as Plaintiffs concede that transportation costs after delivery to the pipeline terminal are properly deducted before royalty calculations.[11] Further, while Amoco argues at length that production ceases at the well head, even Anderson, while disagreeing with the definition of "marketable product" as adopted by Colorado, continues to urge some form of "marketable product" rule, Anderson II; see also Anderson IV, at 336 and V, at 17, 25. Finally, the "severance rule" advocated by Amoco was expressly rejected in *Rogers*, at 901; see also *Garman*, at 657-61. The Court declines to reconsider the specific holdings of *Rogers* and *Garman*.

A. Implied Covenant to Market

The *Rogers* court interpreted "at the well" or "at the mouth of the well" language in royalty instruments to be silent with respect to allocation of costs, *Id.*, at 896-902. Under *Rogers* this Court must begin its analysis with the implied covenant to market, which obligates the lessee to incur costs necessary to render the gas marketable. *Id.*, at 902. This analysis applies equally

---

[11] That portion of *Rogers* addressing long-distance transportation would appear to be *obiter dictum*, as the only issues in *Rogers* were costs incurred before delivery to the interstate

to royalty interest owners as to overriding royalty interest owners. *Id.* The *Rogers* court relied on its earlier decision in *Garman* as a framework in stating,

> In defining whether gas is marketable, there are two factors to consider, condition and location. First, we must look to whether gas is in a marketable condition, that is the physical condition where it is acceptable to be bought and sold in a commercial marketplace. Second, we must look to location, that is, the commercial marketplace, to determine whether the gas is commercially saleable in the oil and gas marketplace.

Rogers, at 905. [footnotes omitted]

B. Marketability is a Question of Fact

While the *Rogers* court noted that gas may have reached the first-marketable product status when it is in the physical condition and location to enter the pipeline, *Id.*, at 905, marketability is a question of fact, *Id.*, at 905, 907. Post-production costs are not deductible as a matter of law: "[W]e disagree that certain costs are deductible in calculating royalties as a matter of law because this view fails to recognize that similar types of costs may be deductible in some circumstances and not deductible under other circumstances". *Id.*, at 906. The costs discussed in *Rogers* included gathering, compressing, dehydrating, and transporting the gas into the

---

pipeline, *Id.*, at 892.

interstate pipeline. Whether costs are deductible is based on whether a first-marketable product has been obtained, not on the label associated with any particular cost. *Id.* at 907:

> Once gas is deemed marketable based on a factual determination, the allocation of all costs can properly be determined. Absent express lease provisions addressing allocation of costs, the lessee's duty to market requires that the lessee bear the expenses incurred in obtaining a marketable product. Thus, the expense of getting the product to a marketable condition and location are borne by the lessee. Once a product is marketable, however, additional costs incurred to either improve the product, or transport the product, are to be shared proportionately by the lessor and lessee. All costs must be reasonable.

The *Rogers* court repeatedly emphasized that to determine the marketability of natural gas, a factual inquiry into the physical condition of the gas and the commercial realities of the oil and gas marketplace is required, *Id.*, at 905, 906, 907 , 909, 910, 911, and 912. The determination of marketability is to be made by the trier of fact, *Id.*, at 906.

C. Standard to be Applied in Determination of "Marketability"

The *Rogers* court noted that *Garman* did not define "marketability" and held that "marketability must be defined to . . . provide guidance to lower courts confronted with litigation addressing these issues," *Id.*, at 903. The *Rogers* court discussed the definition of marketability at length:

> "Among the facts and circumstances which are to be considered in the determination of the lessee's diligence in marketing are, the availability of marketing facilities, such as

pipe lines and the efforts of the lessee in securing the extension of pipelines into the field; the pressure and quality of gas as affecting its marketability; the cost of pumping oil, the amount produced, and the prevailing market price therefor; and the time and manner of the performance of such acts as might result in marketing."

Id., at 903-04, quoting 2 W. L. Summers, *The Law of Oil and Gas*, §415, at 634.

In determining whether a lessee has met the obligations imposed by the implied duty to market, we look to the nature of the lessee's duty to market, and, implicitly, how a determination of marketability is made. In a footnote in *Garman*, we referred to two definitions of marketable condition. We said that "marketable means 'fit to be offered for sale in a market; being such as may be justly and lawfully bought or sold .. wanted by purchasers.' " *Garman*, 886 P.2d at 660 n. 26 (quoting *Webster's 3rd New International Dictionary* 1383 (1986)). We next stated that "Williams and Meyers define marketable condition as gas 'sufficiently free from impurities that it will be taken by a purchaser.' " *Garman*, 886 P.2d at 660 n. 26 (quoting 8 Williams & Meyers at 692). Although seemingly helpful, those definitions were not incorporated into our discussion in *Garman* in defining the lessee's duty under the implied covenant to market, nor did we explain the meaning of those broad definitions. Certainly, these definitions could be interpreted as supporting our view here that in order to be marketable, gas must be in a certain physical condition, as well as being fit for sale in a commercial market. Accordingly, we consider these definitions consistent with our holding in this case. However, in order to fully understand the concept of marketability, we must go beyond those definitions.

We believe that the theory of the first-marketable product is helpful in guiding our definition of marketability, and what is meant by gas being in a marketable condition. Thus, in defining marketability, we look to the first-marketable product rule for guidance, but do not adopt it in its entirety. The first-marketable product rule states that "the point where a marketable product is first obtained is the logical point where the exploration and production segment of the oil and gas industry ends, is the point where the primary objective of the lease contract is achieved, and therefore is the logical point for the

> calculation of royalty." Anderson, Part 2, *supra*, at 637. Thus, this rule provides that royalty calculations should be made at the point where a first-marketable product has been obtained. *Id.* at 639-40. Under this theory, "the point at which gas first becomes a marketable product would be established on the basis of a known and real market." *Id.* at 640-41. "Production," and thus, the lessee's duty to produce a marketable product, would end when a first- marketable product has in fact been obtained. *Id.* at 642. Thus, depending on the factual scenario, "production" could end at the point of extraction, or elsewhere. *Id.*

Rogers, at 904. [footnotes omitted]

> There is a distinction between acts which constitute production and acts which constitute processing and refining of gas extracted by production. 3 [Eugene] Kuntz [*The Law of Oil and Gas*], § 40.5 at 351.
>
>> "Unquestionably, under most leases, the lessee must bear all costs of production. . . . It is submitted that acts which constitute production have not ceased until a marketable product has been obtained. . . . " *Id.*
>
> In looking to the first-marketable product rule for guidance in defining marketability, we must look to the practical implications of such a rule. In defining whether gas is marketable, there are two factors to consider, condition and location. First, we must look to whether the gas is in a marketable condition, that is, in the physical condition where it is acceptable to be bought and sold in a commercial marketplace. Second, we must look to location, that is, the commercial marketplace, to determine whether the gas is commercially saleable in the oil and gas marketplace.
>
> A market is a "[p]lace of commercial activity in which goods, commodities, securities, services, etc., are bought and sold." Black's Law Dictionary 970 (6th ed.1990). It is also defined as "[t]he region in which any commodity or product can be sold; the geographical or economic extent of commercial demand." *Id.* Thus, the determination of when gas is

> first- marketable is driven in part by the commercial realities of the marketplace. . . .
>
> It may be, for all intents and purposes, that gas has reached the first- marketable product status when it is in the physical condition and location to enter the pipeline. See *TXO Prod. Corp.*, 903 P.2d at 262-63 (implying that the standard for determining when gas is marketable is when it is fit to enter the pipeline, because costs of dehydration and gathering, which are required in order for the gas to enter the pipeline, are expenses borne by the lessee as part of the duty to market gas, and are not deductible expenses from royalty payments); *R.E. Yarbrough & Co.*, 122 IBLA 217, 223 (1992)(gas not in marketable condition until prepared for delivery into pipeline); Wyo. Stat. § 30-5-304 (2000)(lessee pays all non-deductible costs of production including costs of gathering, compressing, dehydrating, and transporting the gas into the market pipeline); Jay G. Martin, *Summary of Significant Gas Market and Transportation Changes Affecting Producers in the 1990's*, 37 Rocky Mtn. Min. L. Inst. § 16.01 (1991)(production function of gas industry includes producer being responsible for "putting the gas into a marketable state by removing its impurities and gathering the gas from the various points of production (well head), and delivering it via gathering lines to a common point for delivery into the large diameter transmission lines").

Id., at 904-05.

> Under the implied covenant to market, the lessees have a duty to make the gas marketable. In analyzing that duty, we look to the first- marketable product rule as guidance and adopt a definition of marketability to include both a physical condition such that the gas would be acceptable for sale in a commercial market, and a location-based assessment, such that it would be saleable in a commercial marketplace. The determination as to when gas is marketable is a question of fact.

Id., at 912.

D. Evidence of Sales as Establishing "Marketability"

The *Rogers* court, while recognizing that a "sale" of gas is evidence of the existence of a market, held that a single sale does not conclusively establish the existence of a market:

> [W]hile we agree that a single purchaser, in a good faith purchase of gas, is evidence that there is a market for the gas, we do not agree that such a purchase conclusively establishes a market. The determination of whether a market exists is an issue of fact to be decided by a jury, based on the facts and circumstances, which may include factors other than a single purchase of gas. The jury instruction here erroneously implies that one sale to a purchaser in good faith establishes marketability. Instead, under our definition of marketability, the gas must be in such a physical condition and location that it is available for commercial exchange, in a viable market, i.e., a commercial marketplace. . . .

Id., at 910.

E. Law on Reasonableness of Costs

Colorado law provides no definition of "reasonable costs"; see *Rogers*, at 906: "Once a product is marketable, however, additional costs incurred to either improve the product, or transport the product, are to be shared proportionately by the lessor and lessee. All costs must be reasonable." See also *Garman*, at 661:

> Upon obtaining a marketable product, any additional costs incurred to enhance the value of the *marketable* gas, such as those costs conceded by the Garmans, may be charged against nonworking interest owners. To the extent that certain processing costs enhance the value of an already marketable product the burden should be placed upon the lessee to show such costs are reasonable, and that actual royalty revenues increase in proportion with the costs assessed against the nonworking interest. [emphasis in original]

Plaintiffs argue that *Garman*, by its reference to "reasonable actual costs," at 661, requires deduction only of actual out-of-pocket operating and maintenance costs and prohibits deductions for cost of capital, rate of return, and depreciation. This Court does not believe that *Garman* can be so read. The reference is to a federal regulation that, by its terms, applies only to contractual or fee processing arrangements, where such costs would not be an issue. Further, the regulation would apply only to the so-called "federal method" leases; see discussion of *Fina*, *infra*.

Anderson argues that "marketable product" jurisdictions should not allow a lessee to take profit on post production costs but should be allowed to recover operating and maintenance expenses, overhead, depreciation, and the cost of money charge for undepreciated capital. Anderson suggests use of Council of Petroleum Accountant Societies ("COPAS") procedures in these calculations. Anderson IV, at 345-58.[12] Anderson cautions, however, that the lessee should not be allowed to deduct a profit rate of return in addition to or in lieu of a cost of money charge and that gathering and transportation expense, whether incurred directly by the lessor or

---

[12] Anderson contrasts the marketable product jurisdiction with a well head value jurisdiction; for well head value jurisdictions, he advocates only actual out of pocket costs and,

by paying a third party, should be treated as a cost item for royalty accounting, not a separate profit center, *Id.*, at 357. Anderson also advocates a "postage stamp" approach that levies the same charge per Mcf. or Btu., regardless of a particular well's location in the field, arguing that a postage stamp rate "is simple to calculate and is fair to all royalty owners," *Id.*, at 342-43.[13]

In *Atlantic Richfield Company v. Farm Credit Bank of Wichita*, 226 F.3d 1138 (C.A. 10, 2000), the Tenth Circuit looked to Anderson IV, at 354-55, and to *Garman* in holding that reasonable costs could include costs of depreciation, including cost of interest during construction, and cost of capital, though it limited the cost of capital to the lessee's actual expenditure and not on the capital expenditure of others, *Id.*, at 1147-48.[14] The Court finds the

---

perhaps, a cost of money charge. Anderson IV, at 335; Anderson I, at 637.

13 Anderson is discussing only transportation costs, or freight, in this article; however, there would seem to be no logical reason why this analysis would not apply to any cost in which the lessor is required to bear a proportionate share, including dehydration, compression, or treatment. Note that Anderson, consistent with his views, would include gathering costs in transportation unless *de minimis*; this "matter of law" approach to allocation of costs is expressly rejected in *Rogers*.

14 *Atlantic Richfield* is cited in *Rogers*, at fn. 11, for its holding that "at the well" language is either silent or allocates transportation costs, *Atlantic Richfield*, at 1150. *Rogers* does not discuss the "reasonable cost" analysis of Atlantic Richfield. To the extent that *Atlantic*

analysis of Professor Anderson and *Atlantic Richfield* to be persuasive.

F. Burden of Proof

The Court agrees with Amoco that Plaintiff has the burden of proof on the issue of marketability. See Amoco's Trial Brief on Marketability.

The writings of Professor Anderson, Anderson V at 23-24, as well as the language of *Garman*, at 660-61, suggest that the burden is on the lessee to show that post-production costs are reasonable. This is contrary to the usual rule for burden of proof, as cited in Amoco's brief. As the Court finds the evidence on reasonableness of costs to be established by a preponderance of the evidence, it is unnecessary to determine who has the burden of proof on this issue.

G. Supplemental Authority

Both parties have cited supplemental authority to the Court, contending that it supports specific parts of their proposed findings and orders. This authority will be discussed briefly.

Plaintiffs cite the decisions of Judge Ossola in *Savage v. Barrett Resources Co,* now captioned as *Savage v. Williams Production RMT*, Case No. 98CV161, District Court, Garfield

---

Richfield holds that leases which are silent require lessors to share in transportation costs as a matter of law, it is of course inconsistent with *Rogers*; however, the Court does not believe that this affects the "reasonable cost" analysis.

County. As correctly stated by Amoco, such decisions are not *stare decisis*. Moreover, as this Court has repeatedly observed, "The determination of whether gas is marketable is a question of fact, to be resolved by a fact finder." *Rogers*, at 906. Factual inquiry is required, and the decision is to be based upon "facts and circumstances" of the case at bar, *Id.*, at 906, 910. Thus, the Court finds the *Savage* decision to be neither persuasive nor instructive.

Amoco relies on *Fina Oil & Chemical Co. v. Norton*, 332 F.3d 627 (D.C. Cir. 2003), as support for the proposition that sales to AETC are valid and that royalties are properly calculated based upon sales to AETC. *Fina*, however, turns expressly upon the statutory definition of "lessee" and the regulations requiring the calculation of royalties based upon gross proceeds to the lessee, *Id.*, at 676. Thus, *Fina* has application only to the so-called "federal method" leases. Plaintiffs also point out, correctly, that a well head sale does not establish the existence of a "market" nor that the gas is "marketable"; see discussion *supra*.

Plaintiffs' citations to *Amoco production Co. v. New Mexico Taxation & Revenue Dept.*, 2003 WL 2180227, __ P. 3d ___ (N.M. Ct. App. 2003) and *Marlin Energy, Inc. v. Sorling, Norturup, Hanna, Cullen & Cochrane, Ltd.*, 243 F.Supp.2d 835 (C.D. Ill. 2003) are not persuasive, for similar reasons. While discussing what is necessary to make gas "marketable," *New Mexico* applies the statutory definition of “processor,” *Id.*, at 3; *Marlin* is based upon the definition of “operator” and “operating,” *Id.*, at 840-41.

VI. APPLICATION OF LAW TO FACTS—LOCATION AND CONDITION AND THE DETERMINATION OF MARKETABILITY.

A. Gas Sold to AETC

Initially, the Court will discuss the 90% of the gas that was sold to Amoco's marketing affiliate, AETC, and finds that these sales were not arm's length sales. Tr. 8/15/02 (White, Hultin). The Court relies on testimony relative to the purposes underlying the formation of AETC and the decision that transfer of title to the gas would take place at the well head rather than at the interstate pipelines. Until April 1991, the historic transfer point had been the interstate pipelines. The title transfer point was moved to the point at which the gas was received into the gathering systems to maximize recovery of post-production costs from the Minerals Management Service of the federal government. P.E. 61. In addition, Defendant's expert Parker testified that only sales of gas between unaffiliated parties are evidence of marketability of gas. Tr. 8/27/02 (Parker). Defendant's expert Kalt relied only on sales between parties acting at arms-length. Tr. 8/28/02 (Kalt). Thus, the Court finds that the sales to AETC are not evidence that the gas is marketable at the well.

B. The 10% Not Sold to AETC

Regarding the 10% of the gas not sold to AETC and as referenced above in Section V.B., The Court finds that this disposition of this 10% is not indicative of a market at the well head for the following reasons:

"Free gas" or "gas taps" does not constitute a sale. Tr. 8/21/02 (Mueller).

"Field uses" for compression require sophisticated technology not available to the ordinary consumer. No sale is involved. Mummery Depo., 10/26/00, p. 14, l. 12 to p. 17, l. 23; Tr. 8/15/02 (White).

"Post-1-1/90 Contract Sales" accounted for only 0.2% of the total.

The "Duke Sales" were arranged by Amoco's defense team, after this action was commenced, to demonstrate that "gas behind Florida River [Plant] could be sold at the well head." Tr. 8/20/02 (Mueller); Tr. 8/21/02 (Mueller). The sale commenced on January 1, 2002, and lasted only four months. Tr. 8/20/02 (Mueller). Amoco provided all of the services depicted on Exhibit A to Plaintiffs' proposed findings of fact necessary to deliver the gas to Duke at the interconnection of the interstate pipeline system. While AETC generally sells gas above the San

Juan Index, Tr. 8/21/02(Mueller); Tr. 8/27/02 (Miller), Amoco agreed to accept the San Juan Index, less gathering costs and an additional 7 cents. Amoco understood that the 7 cents represented a "discount price," Defendant's Ex. 2199, and the "[d]iscount should cause [Duke] to make the gas flow." Defendant's Ex. 2201; Tr. 8/27/02 (Miller).

The "Greeley Gas Sale" was also arranged by Amoco's defense team to show "the usability of this gas.. and the fact that it could be burnt and sold at or near the well." Tr. 8/20/02 (Mueller). That sale began in March, 2002. Amoco offered San Juan Index, less 55 cents/mcf to induce Greeley to purchase the gas. Tr. 8/21/02 (Mueller). Greeley's system is not nearly large enough to take the total volume of CBM gas Amoco produces in southern Colorado. Tr. 8/21/02 (Mueller). The gas comes from one well with a CO_2 content of 1% and must be dehydrated and compressed before delivery. Tr. 8/15/02 (White); Tr. 8/20/02 (Mueller).

The "Vastar Sale" involves two Amoco-operated wells. Tr. 8/20/02 (Mueller), Vastar is now an affiliate of Amoco. Tr. 8/21/02 (Mueller). The gas is eventually dehydrated, compressed and treated for delivery and consumption outside the Basin. Tr. 8/15/02 (White).

“Post 1-1/90 Contract Sales” were made to El Paso while Amoco was constructing the Florida River Plant and ceased when the plant went on line. Amoco was unable to sell all gas it could produce, because the gas had to be blended with conventional gas to meet El Paso's CO_2 requirements, and the gas was also compressed and dehydrated to meet pipeline specifications. Tr. 8/15/02 (White).

The "POI Sale (CO Portion only)" represents fuel consumed by compressors operated by POI on Amoco's gathering systems. Tr. 8/20/02 (Mueller). Such fuel is a cost of Amoco's operations and is not evidence of a market. Tr. 8/21/02 (Mueller)

The "La Plata Airport Sale" covers sales from 1987 through 2000 (other testimony says ten years) off of Amoco's gathering system from wells with a CO_2 content of 2.5%. Tr. 8/20/02 (Mueller); Tr. 8/21/02 (Mueller). The gas was dehydrated before the airport used it. Tr. 8/15/02 (White). The price of the gas was 100% of the San Juan Basin Index. Tr. 8/21/02 (Muller), "The airport took everything it needed from that tap". Tr. 8/21/02 (Mueller).

The "PSCO Bayfield Sale" covers gas sold to PSCO for the Town of Bayfield, Colorado, during the winter of 1995-96. It was delivered off the Red Cedar gathering system adjacent to the town. The contract has terminated. The gas was priced at 100% of the San Juan Index. Mummery Depo. 10-26-02, p. 40, l. 6 to p. 42, l. 23; Tr. 8-21-02 (Mueller); Defendants' Ex. 3017. The contract identified seven conventional wells located 10 miles from Bayfield as the source of the gas. Tr. 8/20/02 (Mueller); Tr. 8-21-02 (Mueller).

The "PSCo Central CO Corridor" represents a four-well field that Amoco developed. Amoco sold the gas, which had a 5% CO_2 content, to Public Service and the CO_2 treatment was installed to comply with Public Service's quality specifications. Tr. 8/22/02 (Mummery).

The "Williams Contract" represents sales lasting for only one month in November, 1991. Tr. 8/21/02 (Mueller); Defendant's Ex. 2806.

While all of these sales were at San Juan Index or below, Amoco usually gets a premium to index. Tr. 8/21/02 (Mueller).

The above described 10% is not conclusive to establish a market existing at the well head because: 1) sales for consumptive use within the San Juan Basin were minimal; 2) in the case of the sales arranged by Amoco’s defense team, these sales did not demonstrate the existence of a "[p]lace of commercial activity in which goods, commodities, securities, services, etc., are bought and sold," *Rogers*, at 905, on any kind of ongoing basis; and (3) GTC services still had to be provided within the basin for the overwhelming percentage of the gas, and (4) most gas was delivered to transmission pipelines.

C. Third-Party Sales

Amoco introduced evidence that there are working interest owners and independent third-party producers, both on its system and others, who either sell their gas to Amoco or AETC at the well or pay Amoco to treat their gas. These producer-owners account for about 2 Mmcf./day. Tr. 8-21-02 (Mueller); Ex.2539. On Amoco's system, there are 21 such owners or producers. To produce their gas, they must either sell it to Amoco or AETC or enter into a gathering agreement with Amoco. *Id.* Again, the Court finds that, both because of the small amount and the requirement that they deal with Amoco, these sales are not indicative of a market at the well head.

Amoco also relies on evidence of well head sales for producers not connected to its GTC facilities (i.e., on another gathering system, such as Red Cedar or Williams Field Services). These sales are discussed *infra*.

D. Acts Constituting "Production"

Both parties presented considerable evidence as to whether the gathering system was necessary to maintain low well head pressure and thus to efficiently produce the wells and maximize CBM production (e.g., Plaintiffs, testimony of Bell and Graham; Amoco, testimony of Mueller). While on balance the Court is inclined to agree that Plaintiffs are correct in this assertion, at least up to the CPD's, the Court finds it unnecessary to resolve the issue. Rather, as discussed above, the issue is the point of marketability, both as to physical condition and location.

E. Amoco's Statements Regarding Markets, Marketing, and Marketability

Plaintiffs point to numerous statements by Amoco as to the need to develop these facilities to market the gas, to get the gas to market, or to make the gas marketable. See, e.g., P.E 17, 18, 26, 40,69, 162, 279, 413, 481, 490. See also P.E. 44, in which Amoco states that low well head pressure requirements, produced water, and CO_2 content prevent direct sales of CBM at the well head. Amoco's use of these terms was consistent with industry practice. Tr. 8-14-03 (White); 8-19-02 (Jensen).

In response, Amoco argues, at length, that these documents and statements refer only to marketing opportunities.

While the Court does not consider these statements to be conclusive, it does consider them to be evidence that Amoco itself considered the only commercial market for natural gas in the San Juan Basin to be at the pipeline terminal. See, e.g., P.E. 17; see also P.E. 26, in which Amoco, in responding to a complaint from Petrogulf Corporation, responded, "The gathering fee is primarily for compression and dehydration of the gas to make it marketable."

F. Evidence of Well head Sales in the San Juan Basin

Amoco introduced evidence at trial regarding historical sales of gas at the well head, dating back to the 1950's. Tr. 8-21-02 (Mueller, Jack). Plaintiffs moved to strike, asserting that this was evidence of industry practice and custom, rejected in *Garman*, at 660. To the extent that Amoco offers this evidence as extrinsic evidence to modify "at the well" lease language, the objection is well taken. The Court finds, however, that the evidence is admissible, along with the evidence regarding deregulation and open access, to explain the history of the ways in which gas was marketed and whether deregulation, open access, changing industry practice, and transmission pipeline requirements have changed the point of marketability. The motion to strike is DENIED.

The evidence established that, at the present time, independent third-party producers or working interest owners in the San Juan Basin, who are not large enough to construct GTC facilities and/or elect to have someone market gas for them, typically sell the gas at the well head to Amoco (or AETC) or, if on another gathering system, to the owner/operator of that system, sell it at the well head to an independent marketing company (in industry parlance, an "aggregator"), or retain title to the gas, enter into a gathering agreement with Amoco or another company providing GTC services, and sell it at the transmission pipeline inlet. Prices for such well head sales are based upon San Juan Index[15] less a deduction charged by the aggregator or purchaser for treatment, administration, etc. Tr. 8/27-28/02, Gosney, Bennington, McCleod, Stewart. Such sales contracts or gathering agreements were at "take it or leave it" prices based upon San Juan Index price, Stewart.[16]

G. Evidentiary Issues

Both parties designated substantial amounts of deposition testimony, 30(b)(6) and otherwise, with counter-designations, objections, supplemental designations, etc.; eleven pleadings were filed on this issue. In addition to line by line objections, each party also incorporates its objections made on the record of the deposition itself.

While at least some of these objections may have technical merit, at least in part, this was

---

[15] The San Juan Index is a published high, low and average of prices for gas at in the inlet to the transmission pipeline. Tr. 8/21/02 (Mueller).

[16] The "take it or leave it" was true even though Stewart, somewhat unusually, had access to two separate gathering systems.

a trial to the Court; given the volume of evidence before the Court, the Court does not find it necessary to address specific objections, with two exceptions. As to the counter and supplemental designations, the Court finds that the doctrine of completeness applies. As to the specific objections to any deposition testimony cited in this Order, the Court finds that, as the trial was to the Court, the objections go to weight, not to admissibility, and the objections are therefore overruled.

VII. THE OPINIONS OF THE EXPERT WITNESSES

Both parties presented experts to testify as to the marketability issue. Plaintiffs' experts both relied upon statements in documents provided by Amoco and the testimony of its witnesses in deposition. Some of Amoco's experts, on the other hand, have disagreed with Amoco's own assessment of what must be done to produce the gas and place it in marketable condition. As is explained below, the Court finds Amoco's attempted use of expert testimony regarding marketing and marketability to be unpersuasive.

Based on information supplied by Amoco and their own knowledge and experience, Plaintiffs' experts concluded that the gas involved in this case is not in marketable condition until it enters the transmission pipeline system. Graham testified that the interstate pipelines constitute a commercial marketplace. (Graham, 8/14/02). Consistent therewith, he opined that the CBM at issue in this case first becomes marketable after it meets all of the tariff specifications of the transporting pipeline and exits the booster compressors at the tailgates of the treatment plants. (Graham, 8/13/02).

Plaintiffs' principal expert on this subject, Mr. White, testified that "marketable" and "merchantable" are synonyms. (White, 8/14/02). He also stated that a "commercial marketplace is where there are buyers and sellers that trade in an identifiable product that is prepared for market", *Id.*, and that the purpose of Amoco's facilities is "to improve the quality of the gas and make it marketable" (White, 8/15/02). Consistent with Amoco's statements in internal documents and to third parties, he also expressed the opinion that its CBM gas must be treated, dehydrated and compressed to reach the market and there is no commercial demand for its raw coalbed gas. *Id.* Consistent with Amoco's previous determination, White also testified that in the San Juan Basin, commercial demand exists only for conditioned gas, at the inlet of the interstate pipelines, where trading, negotiation, and open bidding is taking place between a large number of buyers and sellers for the gas, which has then become a fungible product. *Id.* White concluded that the well heads involved in this case do not constitute a commercial marketplace.

Id.

Amoco introduced evidence through its expert, Dr. Parker, of well head sales currently taking place in the San Juan Basin in Colorado and New Mexico for both conventional and CBM gas. Based on his survey of producers of CBM gas in the San Juan Basin, Dr. Parker testified that the gas involved in this case is "marketable" at the well. The premise underlying both his opinion and his survey is that, if gas can be sold, it must be marketable. (Parker, 8/27/02). Because Dr. Parker's survey methodology was admittedly incomplete,[17] the Court attaches little weight to his testimony. Even were his figures to be reliable, however, Dr. Parker conceded that, if the affiliate sales are not "arm's length" transactions, his data may have no relevance to whether gas is marketable at the well head. Moreover, he made no investigation to determine whether the well head sales were idiosyncratic, although he had previously testified that such sales would not constitute evidence of a market (Parker, 8/27/02). According to Dr. Parker, about 88% of CBM gas is sold at the well head. If sales to affiliates were excluded, about 10%

---

[17] He conceded that data from the Colorado Oil & Gas Conservation Commission was not complete and that he was not able to contact every company for which he did have data. Further, he disclosed to the entities contacted that he was working for Amoco and read them a statement which arguably indicated to the respondent that its interest could be

of the gas was sold at the well head, which in Dr. Parker's opinion was still "significant." Tr. 8/27/02; Ex. 2574. As discussed above, such sales are based upon San Juan Index and are “take it or leave it” transactions; thus, the Court finds that Dr. Parker’s opinion is not supported by the evidence.

Amoco also presented testimony by Dr. Joseph Kalt, an economist, in support of its contention that a commercial marketplace exists at the well head. Dr. Kalt defined a "commercial market" as "activity of buying, selling, negotiating [and] offering between buyers and sellers such that arm's length transactions can bring the forces of supply and demand [and] the marketplace to bear in establishing prices, contracts [and] volumes in that commercial activity” (Tr. 8/28/02).

Kalt based his conclusion that there was a commercial market at the well head solely on the existence of some "commercial activity" at the well head in the San Juan Basin, without considering the extent of such activity or whether commercial demand is present or whether competitive bidding among buyers and sellers, reflecting market forces, is actually taking place at that location. Dr. Kalt also testified that participants in well head sales typically use the San

---

affected by the litigation. See. Ex. 605. The surveys included CPD sales as well head sales.

Juan Index price, less GTC costs, to establish the well head price because the parties have no other basis to set well head prices. Tr. 8/28/02 (Kalt). Thus, the Court concludes that, under Dr. Kalt's definition, there is no evidence of market forces, supply and demand, or buyers and sellers to support his opinion that there is a commercial marketplace at the well head.

Amoco's witnesses conceded that when Amoco used the term "marketable" or terms of equivalent import, it was referring to pipeline-quality gas, and that the gas industry as a whole has commonly used the term "marketable" in that way. (Kelley Depo., 7/10/02, p. 26, l. 10 to p.29, l. 7; p. 49, l. 9 to p. 50, l. 23; p. 53, ll. 3-16l p. 65, l. 21 to p. 67, l. 16; Mitchell, 8/19/02; see also PE 89 at PL02172; PE 35 at PL03180; PE 458 at PL01832).

VIII. FINDING ON MARKETABILITY

This case presents factual issues present in no reported case of which this Court is aware. Amoco argues, correctly, that for many years all gas in the San Juan Basin was sold at the well head and that aggregators and small producers are evidence of a marketplace at the well head. The Court does not find this to be dispositive, for the following reasons.

Even were the Court to find that gas, either conventional or CBM, was marketable at the well head from the 1950's through the 1980's (as to which the Court makes no finding), the Court believes that “open access” resulted in a fundamental change in the commercial marketplace for gas. While it is true that independent producers do make well head sales to Amoco, aggregators, or other GTC operators, everyone is looking downstream to the sales taking place at the plant tailgate, and such well head or intermediate sales are based upon San Juan Index, with a very limited number of potential buyers. These buyers then market the gas (after GTC) at the plant tailgate or even further downstream.

Having considered the evidence and the opinions of the experts, the Court finds that gas in the San Juan Basin (Colorado portion) is marketable, both as to physical condition and location, only after gathering, compression and treatment and delivery to the inlet for the interstate pipeline.

Amoco argues that such a finding unfairly penalizes Amoco for vertical integration and efficient operation and that other producers, who do not have their own GTC facilities, can still pay royalty based upon well head sales. This conclusion does not follow. The same analysis of marketability, both as to physical condition and location, would apply whether the producer is vertically integrated or not.[18]

The foregoing finding of marketability is applicable to the so-called “federal method” leases in Subclass 2; however, any costs expressly deductible pursuant to the CFR and cases interpreting same, e.g., *Fina*, *supra*, would be deductible notwithstanding the finding of marketability. See Orders of October 23, 1997 and June 28, 2002.

IX. REASONABLENESS OF COSTS

Plaintiffs argue that where GTC costs can be deducted, in whole or in part, pursuant to express lease provisions, Amoco overcharged the lessors by including profit on equity capital investment and by including capital and depreciation for facilities not paid for by Amoco, specifically, a booster compressor installed by El Paso and power line constructed by La Plata Electric Association ("LPEA"). Plaintiffs also argue that the "postage stamp" approach[19] should

---

18 Other producers in the basin are not before the Court in this case; thus, this decision is not binding upon them. However, were such producers before this Court, on the identical evidence, the finding as to marketability would be the same.

19 By "postage stamp", the parties refer to a procedure whereby a fee was established for each set of GTC facilities and deducted from royalty payments at a uniform charge per Mcf. for all wells on the system. See Tr. 8-14 and 15-03 (Hultin); P.E. 73.

not be used because it charges wells that do not have CO_2 content in excess of pipeline standards for removal of CO_2. Finally, Plaintiffs argue that the lessors should not be charged for excess plant capacity and that the charges should be reduced based upon actual plant throughput; i.e., that capital and depreciation should be reduced by the proportion that throughput bears to capacity. Tr. 8-15-02 (Hultin); P.E. 602. Amoco argues that it should recover a reasonable rate of return on its investments of 12%. Tr. 8/23/02 (Lukens); Ex. 2641.

The Court agrees in part with Plaintiffs as to capital investments not made by Amoco (El Paso compressors only). While Amoco testified that El Paso agreed to provide such compressors in settlement of a rate dispute, there was no evidence before the Court which showed that these charges were related to GTC facilities at issue here. As to the LPEA transmission line, however, subsequent testimony showed that Amoco did pay $12MM to LPEA, to be recouped in reduced operating rates (Tr. 8/23/02, Lukens; Tr. 8-26-02, Jensen); both the capital investment and reduced electrical rates are properly included in reasonable costs. The Court also agrees that a rate of return on equity capital and, if borrowed, the actual interest paid on borrowed funds, are reasonable and necessary costs; see Anderson IV and *Atlantic Richfield*, discussed *supra*. As to CO_2 content, it was not economically practical to isolate wells with $C0_2$ content above and below

2%, Tr. 8/22/02 (Mummery), and accounting for individual wells would be a nightmare, Tr.8/23/02 (Lukens). The Court believes that the "postage stamp" approach, which Plaintiff's expert, Hultin, conceded to be generally appropriate, is an reasonable method of assessing costs; see also Anderson IV, *supra*. Finally, with respect to throughput, the Court finds that in the plant capacity design, Amoco was exercising reasonable, good-faith business judgment. See Anderson IV, at 358 ("assessment of operator's prudence should be based upon the circumstances and outlook existing at the time the downstream marketing decision was made, not on hindsight") and 359 ("a court should not be quick to second-guess the good-faith business judgments of the lessee without some objective reason").

Plaintiffs also argue that Amoco has failed to show that the costs incurred "enhance" the value of the marketable product, citing *Garman,* at 660-61:

> Our answer is limited to those post-production costs required to transform raw gas into a marketable product. As we explained at the outset, many different types of expenses may be involved in the conversion process. Upon obtaining a marketable product, any additional costs incurred to enhance the value of the marketable gas, such as those costs conceded by the Garmans, may be charged against nonworking interest owners. To the extent that certain processing costs enhance the value of an already marketable product the burden should be placed upon the lessee to show such costs are reasonable, and that actual royalty revenues increase in proportion with the costs assessed against the nonworking interest.

The Court rejects Plaintiffs' argument, for two reasons. First, the costs are incurred to make the gas "marketable" (though, if to be borne proportionately by the lessor pursuant to express lease language, the Court agrees that they must still be "reasonable"). Second, as there is no market at the well, except that dictated by Amoco, other operators of GTC facilities, or aggregators who are basing this price upon San Juan Index less GTC, there is nothing to enhance.

Thus, the Court concludes that (1) the "postage stamp" approach is reasonable; (2) Amoco improperly included a capital investment which it did not make; and (3) Amoco is entitled to actual interest on that portion of undepreciated capital financed by borrowing and a reasonable cost of money charge for that portion financed with equity capital. As the determination of damages is bifurcated, and the various financial information before the Court does not calculate these charges according to this exact methodology (e.g., P.E. 602, Ex. 2641), the Court reserves determination of the amount of overcharge for the damages phase of this case.

X. AMOCO'S AFFIRMATIVE DEFENSES

Amoco has pleaded the affirmative defenses of waiver, estoppel, and acquiescence.

There is no evidence that any royalty owner knowingly or intentionally waived or relinquished any rights in regard to any claims against Amoco. Waiver is the intentional relinquishment of a known right. *Universal Resources Corp. v. Ledford*, 961 P.2d 593 (Colo.App. 1998).

Likewise, there is no evidence that Amoco was in any way misled or harmed by, or that it relied upon, any statement or conduct by any royalty owner. Amoco cites *O'Hara v. Coltrin*, 637 P.2d 398 (Colo. App. 1981), for the proposition that the lessors' acceptance of underpayment of royalties estops them from asserting a claim for underpayment. The Court finds *O'Hara* factually and legally distinguishable. *O'Hara* involved one delay rental payment, not royalties, that was two days late and was accepted without protest. Delay rental payments for all other years were timely paid and accepted and the action to terminate the lessee's interest was not brought until eight years after the late payment.

Finally, the Court agrees with Plaintiffs that, even setting aside the evidence of questions, challenges and objections by royalty owners to Amoco's royalty deductions, a royalty owner's acceptance of underpayments does not constitutes ratification, waiver, estoppel, or acquiescence, *Holmes v. Kewanee Oil Co.*, 233 Kan. 544, 664 P.2d 1335, 1341 (1983).

Thus, the Court finds that Amoco has not established its affirmative defenses, either by a preponderance of the evidence or as a matter of law.

X. FINDINGS AND ORDER

1. The detailed findings as to marketability and reasonableness of costs, *supra*, are adopted as the order of the Court on these issues.

2. Preliminary status conference to discuss course of further proceedings is set for 4:00 p.m on Oct. 16, 2003 (1 hour). Out of town counsel may appear by telephone.

3. In view of the complexity of this case, the Court finds *sua sponte* that the time for filing of C.R.C.P. 59 motions should be extended to 60 days from the date of this Order.

IT IS SO ORDERED.

Done in Chambers this 6th day of October, 2003.

David L. Dickinson
District Court Judge

Xc: All counsel–e-file