XTO ENERGY, INC.

185 IBLA 219 Decided February 4, 2015

United States Department of the Interior
Office of Hearings and Appeals
Interior Board of Land Appeals
801 N. Quincy St., Suite 300
Arlington, VA 22203

XTO ENERGY, INC.

IBLA 2013-90 Decided February 4, 2015

Appeal from an Order to Perform Restructured Accounting and Pay Additional Royalties of the Director, Office of Natural Resources Revenue. 10-00872-002.

Affirmed.

1. Federal Oil and Gas Royalty Management Act of 1982: Royalties--Mineral Leasing Act: Royalties--Oil and Gas Leases: Royalties: Generally

   Where there is no evidence that appellant's gas could have been sold as it emerged from the field compressors, appellant has not established that a true market for the gas in its uncompressed state existed as shown by an established demand for it. The question in each case is whether the typical third party purchaser would accept the gas without the added compression, carbon dioxide removal, and/or dehydration required by the pipeline delivering it.

2. Federal Oil and Gas Royalty Management Act of 1982: Royalties--Mineral Leasing Act: Royalties--Oil and Gas Leases: Royalties: Generally

   While compression, dehydration, and sweetening may serve to facilitate transportation or processing, once it is properly determined that such costs were incurred principally to place the gas at issue in marketable condition and are therefore royalty-bearing, they cannot also be the subject of a transportation or processing allowance.

APPEARANCES: Bruce Bowers, Esq., Fort Worth, Texas, Jonathan A. Hunter, Esq., and Sarah Y. Dicharry, Esq., New Orleans, Louisiana, for XTO Energy, Inc.; Matthew J. Wheeler, Esq., Office of the Regional Solicitor, U.S. Department of the Interior, Lakewood, Colorado, for the Office of Natural Resources Revenue.

OPINION BY ADMINISTRATIVE JUDGE PRICE

XTO Energy, Inc. (XTO) has appealed from a July 31, 2012, Order to Perform Restructured Accounting and Pay Additional Royalties (Order) issued by the Director, Office of Natural Resources Revenue (ONRR), requiring XTO to pay additional royalties in the amount of $10,187.22 for the sample month of January 2006, and to perform restructured accounting and compute and pay any additional royalties due for January 2006 onward.[1] The Order pertains to all natural gas produced from XTO's Federal onshore oil and gas leases and transported by the San Juan Gathering System to the nearby processing Chaco plant.[2] Order at 1. The Director determined that XTO had erred in calculating royalties by failing to place the gas in marketable condition at no cost to the Federal Government, specifically by improperly deducting the costs of compressing the gas from the gross proceeds from sale of the gas in valuing it for royalty purposes.

Because XTO has not demonstrated any error in ONRR's determination to require it to perform restructured accounting and pay additional royalties, we will affirm the Director's July 2012 Order.

Background

From January 1, 2006, through December 31, 2010, there is no question that XTO produced and continues to produce natural gas from numerous wells on Federal leaseholds in the San Juan Basin, New Mexico, and has used and continues to use EFS's San Juan Gathering System to move it from the wellhead to EFS's processing plant. At the processing plant, the gas is subjected to a cryogenic process to extract natural gas liquid products (NGLPs), leaving residue gas, which are sold separately. The residue gas is returned to XTO at the tailgate of the processing plant and placed in the mainline pipeline to deliver the gas to XTO's ultimate purchasers.

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[1] Prior to 2010, the royalty management functions of ONRR were exercised by the Minerals Management Service (MMS). *See* 75 Fed. Reg. 61,051 (Oct. 4, 2010).

[2] The San Juan Gathering System is or was owned by Enterprise Field Services, LLC (EFS), or its predecessor-in-interest (El Paso Field Services Company (EPFS)). References to EFS, a subsidiary of Enterprise Products Partners L.P., include EFS and EPFS. EFS owns and operates the Chaco and San Juan processing plants in the vicinity of the leaseholds at issue. All of the gas at issue in this appeal has been and continues to be processed through the Chaco plant.

Under a December 1, 2006, Gas Dedication, Gas Gathering and Production Area Services Agreement (Agreement), EFS charges XTO transportation fees (reported as gathering charges) and fees for the "field services" it provides that include, but are not limited to, the following: electrical compression fees, global compression fees, global compression electric fuel fees, global compression fuel fees, and lateral compression fees (field service fees). The State considered the services covered by these fees to be "part of transportation services that are necessary to place production into marketable condition." Audit Issue Letter, dated Nov. 30, 2011, at 3, (Administrative Record (AR)) at 452. In subsequently computing the royalty on the gas produced from its leases, XTO deducted a transportation allowance from its gross proceeds[3] for field service fees and therefore paid royalty on the value of the gas, less those costs.

The regulation at 30 C.F.R. § 202.150(b) (2006) required XTO, the lessee, to pay royalty on all gas produced from a Federal oil and gas lease, except gas unavoidably lost or used on or for the benefit of the lease.[4]

In valuing unprocessed gas sold under an arm's-length contract for royalty purposes, 30 C.F.R. § 206.152 (2006) required XTO to value the gas based on the gross proceeds accruing to the lessee from its sale, less appropriate deductions under 30 C.F.R. §§ 206.156 and 206.157 (2006) for the reasonable actual costs of transporting the gas to a point of sale outside the lease.

In valuing processed gas sold under an arm's-length contract for royalty purposes, 30 C.F.R. § 206.153 (2006) required XTO to value the gas based on the combined value of the residue gas and all gas plant products derived from processing the gas, less appropriate deductions under 30 C.F.R. §§ 206.156 and 206.157 (2006)

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[3] Under 30 C.F.R. § 206.151 (2006), "[g]*ross proceeds* . . . means the total monies and other consideration accruing to an oil and gas lessee for the disposition of the gas, residue gas, and gas plant products produced." It "includes, but is not limited to, payments to the lessee for certain services such as dehydration, measurement, and/or gathering *to the extent that the lessee is obligated to perform them at no cost to the Federal Government*." (Emphasis added.)

[4] The regulations for valuing Federal gas for royalty purposes at all relevant times were set forth in 30 C.F.R. §§ 206.150 through 206.159 (2006). They were promulgated effective Mar. 1, 1988. *See* 53 Fed. Reg. 1230, 1271 (Jan. 15, 1988), and were redesignated as 30 C.F.R. §§ 1206.150 through 1206.159, effective Oct. 1, 2010, without substantive change. *See* 53 Fed. Reg. at 1230; 75 Fed. Reg. at 61,069, 61,072-74.

for the reasonable actual costs of transporting the gas, and, under 30 C.F.R. §§ 206.158 and 206.159 (2006), for the reasonable actual costs of processing the gas.[5] The processing allowance was generally limited to 66-2/3% of the value of the gas plant products derived from processing the gas, unless the lessee requested and received authorization for a processing allowance greater than 66-2/3%, after demonstrating the actual, reasonable, and necessary processing costs exceeded that limit. *See* 30 C.F.R. § 206.158(c) (2006).

Whether valuing unprocessed or processed gas, it must be put in marketable condition[6] at no cost to the Federal government, in accordance with 30 C.F.R. §§ 206.152(i) and 206.153(i) (2006). *See Amoco Production Co. v. Baca*, 300 F. Supp. 2d 1, 7 (D.D.C. 2003), *aff'd*, 410 F.3d 722 (D.C. Cir. 2005), *aff'd*, 549 U.S. 84 (2006) ("The marketable condition rule is pivotal in the calculation of royalties because it affects the determination of a lessee's gross proceeds, and therefore the value of production."). Gathering, compressing, dehydrating, sweetening, and otherwise treating gas are costs incurred to place gas in marketable condition. XTO therefore was not entitled to deduct any of the costs incurred to place the gas in a marketable condition from the royalty value of the gas.

For royalty valuation purposes, when such costs are incurred by the lessee, either because the lessee undertakes the conditioning tasks and bears the expense or

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[5] The allowable transportation costs included the costs to transport the gas from the lease to the processing plant and then from the plant to a point of sale.

[6] Under 30 C.F.R. § 206.151 (2006), "[*m*]*arketable condition* means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." A "*[f]ield*" is defined as the geographic region encompassing one or more subsurface oil and gas reservoirs, and an "*[a]rea*" is the geographic region, at least as large as a field, in which the "oil and/or gas lease products have similar quality, economic, and legal characteristics." *Id.*

The regulatory language requiring that gas from Federal leases be placed in marketable condition without cost to the Federal government dates from 1988, and reflects a longstanding principle of royalty valuation. 53 Fed. Reg. at 1275, 1277; *see, e.g.*, *Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030, 1036-38 (D.C. Cir. 2008), *cert. denied*, 558 U.S. 819 (2009); *California Co. v. Udall*, 296 F.2d 384, 387-88 (D.C. Cir. 1961); *The Texas Co.*, 64 I.D. 76, 79 (1957); 43 C.F.R. § 3162.7-1(a) ("The operator shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land.").

pays a third party to undertake the tasks, they may not be deducted from the gross proceeds accruing to the lessee. When such costs are incurred by the purchaser or any other party on behalf of the lessee and deducted from the amounts due the lessee, they must be added back into the gross proceeds accruing to the lessee under the sale, because such costs are "ordinarily . . . the responsibility of the lessee." 30 C.F.R. §§ 206.152(i) (unprocessed gas) and 206.153(i) (processed gas) (2006); *e.g.*, *Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 7 ("[R]oyalties are due on the value of the gas in a certain condition-marketable condition-whether or not the producer pays the necessary conditioning costs directly or indirectly."), 12 ("The marketable condition rule anticipates and prohibits the type of arrangements . . . wherein producers offer reduced prices to purchasers who in turn incur the costs of placing gas in marketable condition."); *AnSon Co.*, 145 IBLA 221, 226 (1998); *Branch Oil & Gas Co.*, 143 IBLA 204 (1998); *Texaco Inc.*, 134 IBLA 109 (1995); *R.E. Yarbrough & Co.*, 122 IBLA 217 (1992).

As stated, ONRR's July 2012 Order stems from the audit of XTO's royalty computations and payments conducted by the State of New Mexico pursuant to section 205 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. § 1735 (2006). The audit period was January 1, 2006, through December 31, 2010. The State considered the pressure of the gas before it entered EFS's transportation system "at the outlet of the . . . [field] compressors," and after it was processed at the Chaco plant, and before the gas entered the mainline pipeline for transmission to market. Order at 5. Based on its analysis, the State determined that the pressure at the compressor outlets was generally "less than 250 psi [pounds per square inch]," whereas the pressure at the tailgate of the processing plant ranged "from 700 to 1,100 [psi]." *Id.* The State concluded that if field compression raised the pressure above 700 to 1,100 psi, *i.e.,* the pressure required to enter the mainline pipeline, the costs of compressing the gas then would be considered transportation costs, noting that under 30 C.F.R. § 1206.157(f) (2010) (formerly 30 C.F.R. § 206.157(f) (2006)), ONRR permitted the deduction of "'[s]upplemental'" compression costs "'only if such services are required for transportation ***and*** *exceed the services necessary to place production into marketable condition.*'" Audit Issue Letter dated Nov. 30, 2011, at 3 (emphasis added), AR at 452 (quoting 30 C.F.R. § 1206.157(f) (2010)).

After the audit, by letter dated November 30, 2011, the State notified XTO of its preliminary determination that XTO owed additional royalties on gas produced in January 2006, in the amount of $10,187.22 as a result of applying the marketable condition rule. The State held that in valuing the gas for royalty purposes, XTO had properly deducted the costs of gathering the gas from the gross proceeds received on the sale of the gas as a transportation allowance, but owed additional royalties because it had improperly deducted the costs of compressing the gas as a transportation allowance.

By letter dated February 2, 2012, XTO challenged the State's determination that it had improperly deducted compression costs. XTO argued the State had not demonstrated an understanding of the engineering and other particulars associated with the compression process or the specific purpose being served by compressing the gas. Rather than being necessary to place the gas in marketable condition, XTO argued compression was necessary to transport the gas to the processing plant. It explained that because of increased production, a bottleneck in the existing transportation system developed, and responding to that circumstance, EFS installed over 50 miles of new pipelines and more compressors to increase its capacity in order to transport production.

In his July 2012 Order, the Director upheld the State's audit findings. He agreed XTO had improperly deducted compression costs because such costs were incurred to place the gas in marketable condition. He acknowledged compression served to transport the gas from the wellhead to the processing plant and, ultimately, to the mainline pipeline, but compression costs could be considered an allowable transportation expense only to the extent they covered the costs of raising the pressure above that necessary for transportation in the mainline pipeline after the gas was processed. The Director found the State's comparison of the pressure of the gas at the compressor outlets to the pressure at the plant tailgate before the gas entered the mainline pipeline persuasive, concluding "the pressure at the compressors *did not reach or exceed* pressure at [the] mainline pipeline." Order at 5 (emphasis added). As field compression did not exceed what was necessary to satisfy "the marketable condition requirements of the mainline pipeline," the costs of compressing the gas before it entered EFS's transportation system constituted part of the process of rendering the gas suitable for marketing: "XTO must compress the gas *to meet the requirements of the mainline pipeline market* for the gas to enter that pipeline which delivers the gas to the purchaser." *Id.* at 3, 4 (Emphasis added); *see id.* at 4 ("[T]he mainline [pipeline] required specifications determine the gas quality at marketable condition."), 5 ("[T]he law defines the pressure at the mainline pipeline[] . . . as marketable condition for XTO's gas."). The Director concluded the compression costs were not an allowable transportation expense (citing, *e.g.*, *Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030 (D.C. Cir. 2008); *J-W Operating Co. Inc.*, 159 IBLA 1 (2003)). *Id.* at 4-5.

The Director therefore required XTO to pay the additional royalties determined by the State audit to be due for the sample month of January 2006 and apply the appropriate royalty computation methodology. In addition, he required XTO to perform restructured accounting for the period after January 1, 2006, within 60 days of receipt of the Order and compute and pay any additional royalties, noting that failure to comply with the Order would subject XTO to civil penalties under section 109 of FOGRMA, 30 U.S.C. § 1719 (2006), and 30 C.F.R. Part 1241, Subpart B (2012). He required XTO to continue to report and pay additional royalties as specified in the Order, stating that a future violation would be deemed to be a willful violation under 30 C.F.R. Part 1241, Subpart B (2012). Finally, the Director stated that, after receiving all of the additional royalties, ONRR would bill XTO for the applicable late payment charges required by 30 C.F.R. § 1218.102 (2012).

XTO timely appealed from the Director's Order.[7]

Discussion

Under section 17(b)(1)(A) and (c)(1) of the Mineral Leasing Act, 30 U.S.C. § 226(b)(1)(A) and (c)(1) (2006), royalty on oil and gas produced from an onshore Federal oil and gas lease is properly computed as a percentage of the "amount or value of the production removed or sold from the lease." The statute does not designate a particular methodology for valuing production for royalty purposes, but it is now well established that the Secretary of the Interior or her delegate is vested with "considerable latitude" in determining that value. *Branch Oil & Gas Co.*, 144 IBLA 304, 306 (1998) (citing *Hoover & Bracken Energies, Inc.*, 52 IBLA 27, 33 (1981), *rev'd, Hoover & Bracken Energies, Inc. v. U.S. Department of the Interior*, No. 81-461-T (W.D. Okla. Nov. 18, 1981), *rev'd*, 723 F.2d 1488 (10th Cir. 1983), *cert. denied*, 469 U.S. 821 (1984)).

A party challenging an order issued by ONRR "must show not just that the results of . . . [ONRR's analysis and conclusion] *could be* in error, but that they *are* erroneous." *Id.*; *see Exxon Corp.*, 118 IBLA 221, 246, 98 I.D. 110, 122 (1991) ("When valuation of production is challenged, an appellant must not merely show that the methodology is susceptible to error, but that an error did, in fact, occur. *Phillips Petroleum Co.*, 109 IBLA [4,] 7 [(1989)].") While XTO faults ONRR for failing to show the costs of compressing the gas were not a transportation cost, the burden is on the lessee to demonstrate error in ONRR's decision by showing the costs were not incurred to place the gas in marketable condition. *See, e.g.*, *Burlington Resources Oil & Gas Co.*, 183 IBLA 333, 352 (2013) (citing *Exxon Corp.*, 118 IBLA at 246, 98 I.D. at 122).

XTO in general contends ONRR's characterization of the costs at issue is not conclusive. SOR at unpaginated (unp.) 2. It alleges ONRR has often incorrectly

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[7] XTO's notice of appeal included a statement of the reasons (SOR) for its appeal and a supplemental SOR (SSOR), each of which will be cited as appropriate.

determined the deductibility of costs in cases involving coalbed methane by relying on the fact that the gas is sold downstream of the well, using that circumstance as a "pretext for treating the gas as not marketable" at the wellhead. XTO contends in such cases ONRR has not recognized that gas is often marketable at the wellhead even if it is transported from the well before it is sold, since "[t]he quality of the gas does not change." Therefore, according to XTO, the costs incurred to transport the gas are properly deductible as a transportation allowance. *Id.* XTO argues the Federal circuit court in *Independent Petroleum Association of America v. Dewitt*, 279 F.3d 1036 (D.C. Cir. 2002), *cert. denied*, 537 U.S. 1105 (2003), acknowledged that ONRR has "improperly treated some true transportation costs as marketing expenses," and mislabeled the costs under the marketable condition rule.[8] *Id.*

XTO further asserts that, under longstanding Board precedent, compression costs are deductible from the gross proceeds received upon the sale of the gas, "as part of the lessee's transportation allowance," when such costs are incurred *for the purpose of moving the gas to market*. SSOR at 1 (citing *Shell Offshore Inc.*, 142 IBLA 71 (1997) (compression); *Exxon Corp.*, 118 IBLA 221, 98 I.D. 110 (1991) (dehydration); *Mobil Producing Texas & New Mexico, Inc.*, 115 IBLA 164 (1990) (compression); *Phillips Petroleum Co.*, 109 IBLA 4 (1989) (gathering and compression)).[9] XTO maintains this is the situation in this case. It states ONRR recognized compression was necessary to transport the gas in the July 2012 Order, when ONRR acknowledged that compression was undertaken because of "the need for greater transportation

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[8] The Federal circuit court addressed the question of the deductibility of particular types of costs in terms of the "usual distinction" between non-deductible marketing costs and deductible transportation costs. It concluded fees incurred in aggregating and marketing gas for downstream sale and intra-hub transfer fees charged by pipelines for assuring the correct attribution of gas quantities to particular transactions are not properly deductible as marketing costs, affirming ONRR, but that unused pipeline demand charges paid to secure firm service for gas quantities in excess of actual shipments were deductible as transportation costs, to that extent reversing ONRR. 279 F.3d at 1041.

[9] We find no substantive disposition of the question of the deductibility of compression costs in *Shell Offshore*, where the Board merely acknowledged that the costs of compression had "already been allowed," 142 IBLA at 74, in *Mobil Producing*, where the Board remanded the case for ONRR to address "which [compression] costs are attributable to transportation," 115 IBLA at 177, or in *Phillips Petroleum*, where the Board remanded the case for ONRR to determine "the amount of th[e] [compression] expenses which may be deducted as reasonable transportation costs," 109 IBLA at 13.

capacity" to eliminate the bottlenecks in the existing transportation system: "[T]he function of the new compression facilities was to enable transportation." *Id.* at 1, 2. XTO therefore contends the Board should reverse the Director's Order as arbitrary and capricious. *See* SSOR at 3.

XTO maintains the requirements of mainline pipelines are "irrelevant to the third-party compression charges XTO deducted," because there is no factual support for the conclusion that compression was necessary to satisfy "'the required quality specifications of the mainline [pipeline] interconnects'" at the tailgate of the plant, and unprocessed gas in the field is "categorically different" from processed gas at the plant tailgate. SSOR at 4 (quoting Order at 5). XTO explains the unprocessed gas is compressed to transport it to the plant, and at the plant the gas experiences a "significant drop in pressure" as the NGLPs are extracted during the cryogenic process, which renders the pre-processing global compression irrelevant to the 'condition' of the residue gas." *Id.* XTO concludes the compression performed by EFS is not intended to place the gas in marketable condition.

The case now before us is distinguishable from that in *Xeno, Inc.*, 134 IBLA 172 (1995), where the Board allowed the lessees to deduct the costs of compressing the gas as a transportation allowance on the basis that such costs were not considered necessary to place the gas in a marketable condition. There, gas at the wellhead was sold by the lessees to a gathering system operator with other gas gathered from the field, and was compressed and resold to a pipeline company at a higher price. The Board was persuaded by evidence that "the pressure of the gas from the wellheads was adequate to gain access to the pipeline market," which was supported by evidence that the lessees had "competing offers to purchase the gas at the wellhead" from two pipeline companies. 134 IBLA at 183, 184. The uncompressed gas therefore was in marketable condition. *See Xeno, Inc.*, 134 IBLA at 182-84; *Amoco Production Co. v. Watson*, 410 F.3d 722, 730 (D.C. Cir. 2005), *aff'd*, 549 U.S. 84 (2006) ("Central to *Xeno* . . . was the fact that the gas was suitable for pipeline access *before* gathering and compression."); *Amerada Hess Corporation v. Department of the Interior*, 170 F.3d 1032, 1037 (10th Cir. 1999) ("*Xeno* reached a different result because the producer company in that case showed that its gas was in marketable condition and could be sold directly from the wellhead."); *Amoco Production Co v. Baca*, 300 F. Supp. 2d at 11; *Bailey D. Gothard*, 144 IBLA 17, 22 (1998), *aff'd*, *Gothard v. United States*, No. CV 98-103-BLG (D. Mont. 1999) ("In *Xeno, Inc.*, the Board found that there was evidence that the gas was under sufficient pressure to be marketable at the time it was first sold by the lessees to [the gathering system operator], and that competing offers to purchase the gas at the wellhead were made.").

In *Exxon Corp.*, 118 IBLA 221, 98 I.D. 110 (1991), the Board similarly allowed the lessee to deduct the costs of dehydrating the gas, again because such costs were not considered necessary to place the gas in a marketable condition. *See Exxon Corp.*, 118 IBLA at 233-35, 240-42, 98 I.D. at 116-17, 119-20. We specifically noted that because no market for the dehydrated gas existed, "[dehydration] was not performed to satisfy market specifications." *Exxon Corp.*, 118 IBLA at 242, 98 I.D. at 120.[10] Dehydration was not necessary to place the gas in marketable condition because it was marketable when it emerged from the wellhead.

[1] In this case, however, there was no evidence of a competitive market for uncompressed gas at the wellhead before ONRR and none has been proffered on appeal. More specifically, there is no evidence that the gas could have been sold at a pressure lower than 250 psi, as it emerged from the field compressors, without which XTO has not established that a "true market" for the gas in its uncompressed state actually existed as shown by an "'established demand'" for it. *Branch Oil & Gas Co.*, 143 IBLA at 206 (quoting *California Co. v. Udall*, 296 F.2d at 388), 207.

Only after the gas was compressed to meet the mainline pipeline's specifications was it acceptable to the ultimate third party purchaser. *See, e.g., Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 10 ("[Although] there was a very limited [local] market for gas in its natural condition, . . . the actual [distant] market was for gas having low levels of CO_2 [carbon dioxide]."). ONRR therefore was justified in concluding, in the words of 30 C.F.R. § 206.151 (2006) ("*Marketable condition*"), that with compression the gas was in "a condition that will be accepted by a purchaser under a sales contract typical for the field or area," and thus rendered marketable. *See, e.g., Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 8-9 ("[M]ost of the gas produced by Plaintiffs from the field or area was conditioned to reduce the level of CO_2 because it was sold for use in distant markets. . . . This was true, the Assistant Secretary noted, whether gas was purchased at the wellhead in its natural state and subsequently conditioned by the purchaser, or purchased at the tailgate of a treatment plant after conditioning."), 12 ("The Court finds that, under the particular circumstances in this case, the Assistant Secretary's decision is a reasonable application of the marketable condition rule. Therefore, Plaintiffs must pay royalties on the cost of conditioning the gas to reduce CO_2 levels.").

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[10] *See Amoco Production Co. v. Watson*, 410 F.3d at 731 ("*Exxon Co.*, 118 I.B.L.A. at 242 (deductible dehydration of gas "was not performed to satisfy market specifications")); *Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 13 ("[I]n *Exxon Corp.*, 118 I.B.L.A. 221 (1991), the Interior Board of Land Appeals determined that dehydration of the gas at issue was not necessary to satisfy market specifications but rather was performed for the sole purpose of facilitating transportation.").

In this situation, we must agree that the costs of the field services enumerated above are properly viewed as costs incurred to place the gas in marketable condition and are therefore royalty-bearing. *See, e.g., Amoco Production Co. v. Watson*, 410 F.3d at 729-30; *California Co. v. Udall*, 296 F.2d at 388 ("In the record before us there is no evidence of a market for the gas in the condition it comes from the wells. The only market, as far as this record shows, was for this gas at certain pressure and certain minimum water and hydrocarbon content."); *The Texas Co.*, 64 I.D. at 79 ("The lessee has not shown that the gas can be marketed at the pressure with which it comes from the wells."). It is the market served by the mainline pipeline that determines the primary purpose of the costs incurred. *Encana Oil & Gas (USA), Inc.*, 185 IBLA 133, 141-42 (2014). The courts and this Board have held more than once that "the question in each case is whether the typical third party purchaser would accept the gas without the added compression, carbon dioxide removal, and/or dehydration required by the pipeline delivering it." *Id.* at 141; *see Burlington Resources Oil & Gas Co.*, 183 IBLA at 354-55, and cases cited.[11]

[2] While compression, dehydration, and sweetening may serve to facilitate transportation or processing, once it is properly determined that such costs were incurred principally to place the gas at issue in marketable condition and are therefore royalty-bearing, they cannot also be the subject of a transportation or processing allowance. *See Devon Energy Corp. v. Kempthorne*, 551 F.3d at 1037 ("[Although] the costs of dehydration and compression can reasonably be interpreted to fall within the compass of 'transportation costs[,]'" ONRR properly held they "are not deductible if their primary function is to prepare the gas to move through the pipelines to the point where gas is purchased."); *Amoco Production Co. v. Watson*, 410 F.3d at 731 ("The logic of the regulations bars an expenditure to place gas in marketable condition from also being an expenditure deductible from gross proceeds as a transportation cost."); *Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 13 ("CO_2 removal is essential in the instant case to place gas in marketable condition. That there exists a corollary benefit in [transporting and] reducing the level of CO_2 [at the treatment facility] does not

[11] In *Burlington Resources*, the appellant argued that compression, dehydration, and sweetening of the gas were not necessary to place the gas in marketable condition, but rather to render the gas suitable for processing, noting that separation of the NGLPs from the residue gas required a significant pressure drop, the water in the gas would freeze and shut down processing, and hydrogen sulfide is corrosive and destructive to the plant. ONRR agreed, but nonetheless concluded that compression, dehydration, and sweetening were necessary, first and foremost, to place the gas in marketable condition, *i.e.*, a condition desirable to typical third-party purchasers of processed gas. *See* 183 IBLA at 354-55.

transform what is a marketing cost into a transportation cost."); *Encana Oil & Gas (USA), Inc.*, 185 IBLA at 139-43.

In valuing processed gas for royalty purposes, a lessee is permitted to deduct from gross proceeds not only the reasonable actual costs incurred by the lessee to process the gas, but also the reasonable actual costs incurred by the lessee to transport the gas to the processing plant and then to a point of sale outside the lease. *See* 30 C.F.R. §§ 206.153(a) and (b)(1)(i), 206.156(a), and 206.157(a)(1)(i) (2006). The processing allowance may not include any costs associated with field compression, which are not considered part of processing.[12] The transportation allowance may include "[*s]upplemental costs for compression, dehydration, and treatment of gas*," but "only if such services are required for transportation and exceed the services necessary to place production into marketable condition," as required by 30 C.F.R. § 206.152(i) (2006). 30 C.F.R. § 206.157(f) (2006).[13]

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[12] *See* 30 C.F.R. § 206.151 ("*Processing*" is defined to exclude "[f]ield processes which normally take place on or near the lease, such as . . . compression.").

[13] In proposing the applicable language in 30 C.F.R. § 206.157(f) (2006) regarding supplemental costs, ONRR explained:

> [ONRR] proposes allowing certain supplemental costs for compression, dehydration, and treatment of gas *only if the transporter requires such services as part of the transportation process*. [ONRR] does not allow any costs for compression, dehydration, and treatment of gas for the purpose of placing gas in marketable condition. It is clear that Federal and Indian lessees must put production in marketable condition at no cost to the lessor . . . . Therefore, [ONRR] requires the lessee to compress, dehydrate, sweeten, and otherwise treat the gas to place it in the condition necessary to meet typical requirements for gas purchase contracts or pipeline standards. [ONRR] recognizes, however, that there may be unusual circumstances where *the pipeline performs **additional** compression, dehydration, or other treatment of gas to remove impurities during the transportation process*.
>
> Under the proposed rule, if the lessee demonstrates that the costs it incurs for these treatment purposes are not related to the treatment required to put the gas in marketable condition, then the lessee can include these costs in its transportation allowance.

61 Fed. Reg. 39,931, 39,934 (July 31, 1996) (emphasis added). In finalizing the proposed rule, ONRR reiterated: "The costs addressed in the rule are costs that may occur in unusual circumstances where *the pipeline performs **additional** compression, dehydration, or other treatment of gas for transportation purposes*. These costs exceed

(continued...)

XTO has not shown that the field service fees at issue exceeded what was necessary to place the gas in marketable condition. *See* Order at 3 ("If [EFS's] compressors raised the pressure beyond the requirements of the mainline pipeline, the compression costs exceeding those requirements can be an allowable transportation deduction under § 206.157(f)[]. In this case, XTO's gas at the outlet of the . . . compressors did not reach or exceed the marketable condition [at 700 to 1,100 psi].").

In sum, we agree with the Director that *Devon* is based on comparable facts and "sets the precedent" for applying the marketable condition rule in this case.[14] Order at 3.

(...continued)
the services necessary to place production in marketable condition." 62 Fed. Reg. 65,753, 65,759 (Dec. 16, 1997) (emphasis added).

[14] In *Devon*, the Federal circuit court detailed the process by which the gas is gathered in the field, processed, and sold:

> The gas produced from the wells is gathered at central delivery points ("CDPs")[.] . . . After the gas leaves a CDP, it goes through a complex series of compression and dehydration processes [starting with screw and reciprocating compressors in the field] as it travels "downstream" to the Buckshot processing plant in preparation for eventual sale. . . . When the gas arrives at the Buckshot Gas Plant [after losing approximately one-third of its highest pressure of 1,200 psi], excess carbon dioxide is removed, the gas is dehydrated, and the gas is compressed from approximately 800 psi to 1,100 psi. At that pressure, Devon delivers the treated gas into one of two lateral pipelines. The gas is transported to various purchasers through these pipelines.

Devon Energy Corp. v. Kempthorne, 551 F.3d at 1034. The court affirmed ONRR's Valuation Determination, finding Devon's deductions of the costs of dehydration and of compression performed at the screw compressors, the reciprocating compressors, and plant were inconsistent with the marketable condition rule, because compression and dehydration were necessary to put the production into marketable condition: "[ONRR's] interpretation of the marketable condition rule to require lessees to compress and dehydrate gas to meet the requirements of the pipelines that serve its typical purchasers is not 'plainly erroneous or inconsistent with the regulation.'" *Id.* at 1035, 1037 (quoting *Thomas Jefferson University v. Shalala*, 512 U.S. 504, 512 (1994)). The court in particular noted Devon's failure to demonstrate its gas was actually sold "at pressures less than 1,200 psi" under contracts typical for the field or area that failed to undermine ONRR's application of the marketable condition rule. 551 F.3d at 1038.

XTO's final contention is that ONRR's conclusion that compression costs are deductible as a transportation expense only when the pressure of the gas after field compression and before the gas enters the processing plant equals or exceeds the pressure acceptable to the mainline pipeline effectively adopted a "precise, unwavering rule that applies across the board to a regulated industry," leaving no room for agency discretion based on the facts of a particular case. According to XTO, ONRR's construction constitutes the adoption of a substantive rule of law, without first complying with the notice and opportunity-for-comment rulemaking requirements of the Administrative Procedure Act (APA), 5 U.S.C. § 553 (2006), and moves the Board to overturn the Order on that basis. SSOR at 5; *see id.* at 4-8 (citing, *e.g.*, *Phillips Petroleum Co. v. Johnson*, 22 F.3d 616 (5th Cir. 1994)).

We do not agree ONRR adopted a substantive rule of law regarding the deductibility of compression costs. To the contrary, ONRR considered the facts and determined the State audit's findings and conclusions should be upheld under relevant case law and regulations cited in the Order.

We hold that the Director properly required XTO to pay additional royalties in the amount of $10,187.22 for the sample month of January 2006, and to perform restructured accounting and compute and pay any additional royalties found to be due from January 2006 onward.

Therefore, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 C.F.R. § 4.1, the decision appealed from is affirmed.

/s/
T. Britt Price
Administrative Judge

I concur:

/s/
James F. Roberts
Administrative Judge