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## WYOMING'S POWDER RIVER BASIN: A STUDY IN FEDERAL ROYALTY VALUATION

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### I. INTRODUCTION<sup>\*\*\*</sup>

The past several years have seen a proliferation of litigation relating to royalty valuation and the deductibility against royalty interests of certain post-production costs. This litigation has been driven by attorneys for private royalty owners attempting to find ways to shift costs onto producers that royalty owners have historically shared under their leases.

Private royalty owners have focused their arguments on lines exempted from Federal Energy Regulatory Commission ("FERC") jurisdiction as non-jurisdictional "gathering" lines. The focus of royalty litigation has been whether these lines and other costs incurred away from the lease line

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are production-related expenses not shared by private royalty owners, or whether they are post-production costs chargeable to royalty owners.

Like private royalty owners, the Minerals Management Service ("MMS") has recently demonstrated its desire not to share in certain downstream transportation costs. The MMS has not taken the position of private royalty owners that the "gathering" lines that find exemption from FERC jurisdiction are production related costs in which the MMS should not be required to share. Rather, the MMS argues that the transportation allowance applies to some transportation functions, but does not apply to other transportation functions like dehydration, some compression, and CO<sub>2</sub> removal. Under the MMS' regulations, the case law, and as a factual matter, the MMS' arguments for allowing certain downstream costs while disallowing others is not persuasive.

## II. PRODUCTION VS. POST-PRODUCTION COSTS

Within the terms of federal oil and gas leases is the requirement that the "royalty on production removed or sold from the leased lands (is to be) computed in accordance with the Oil and Gas Operation Regulations . . . ." The operating regulations governing the valuation of gas for the purpose of computing the federal royalties are now found in 30 C.F.R. §§ 206.150 *et seq.* (2003).<sup>1</sup> Section 206.151 contains definitions of "gathering" and of the "transportation allowance:"

"Gathering" means the movement of lease production to a central accumulation and/or treatment point . . . .

"Transportation allowance" means an allowance for the reasonable, actual costs incurred by the lessee for moving unprocessed gas, residue gas, or gas plant products to a point of sale or point of delivery off the lease, unit area, communitized area, or from a processing plant, excluding gathering, or an approved or MMS-initially accepted deduction for costs of such transportation, determined pursuant to this subpart.<sup>2</sup>

Also see § 206.156(a):

Where the value of gas has been determined . . . at a point (e.g., sales point or point of value determination off the lease), MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed

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1. 30 C.F.R. §§ 206.150 – 206.160 (2003).

2. 30 C.F.R. § 206.151 (2003).



gas, residue gas, and gas plant products from a lease or a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.<sup>3</sup>

These operating regulations have been in force since 1988.<sup>4</sup> The federal system does not allow a deduction for the costs of gathering, defined as gathering close to the lease line, but does allow a deduction of the costs of transportation of the gas from the lease. The federal regulations demonstrate that the MMS recognizes the clear distinction between what is meant by “gathering” for royalty valuation purposes, and how that term is applied by other agencies, such as how the term “gathering” is used by FERC in regulating the interstate transportation of natural gas, or as defined in the Pipeline Safety Act. In comparison, in Wyoming, and in other jurisdictions where natural gas is produced, costs of transportation of gas from the place of production to a processing plant or to a distant point of sale have likewise been shared by royalty owners.<sup>5</sup> Given the timing of the 1988 MMS rule revisions in which production related gathering was defined as the “central point of accumulation” and the 1989 amendments to the Wyoming Royalty Payment Act that included production related gathering as a non-deductible cost of production, it is hard to believe that the Wyoming Legislature meant that production related gathering included anything other than the central point of accumulation of the wells on or close to the lease line.

Under the Wyoming Royalty Payment Act,<sup>6</sup> the lease controls the payment of royalties.<sup>7</sup> In the rare instances in which no express lease terms govern royalty payments, royalty interests are defined to mean a “share of production, free of the costs of production . . .”<sup>8</sup> Under Section 30-5-304(a)(vi), “Costs of production” is defined as,

all costs incurred for exploration, development, primary or enhanced recovery and abandonment operations including, but not limited to lease acquisition, drilling and completion, pumping or lifting, recycling, gathering, compressing, pressurizing, heater treating, dehydrating, separating, storing or transporting the oil to the storage tanks or the gas into the

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3. 30 C.F.R. § 206.156 (2003).

4. 30 C.F.R. §§ 206.150 – 206.160 (2003).

5. See *State of Wyoming v. Davis Oil Co.*, 728 P.2d 1107, 1109 (Wyo. 1986); *Kretzni Development Co. v. Consolidated Oil Corporation*, 74 F.2d 497 (10th Cir. 1934) (a case arising in Wyoming). For decisions on this point from other jurisdictions, see, e.g., *Heritage Resources, Inc. v. NationsBank*, 939 S.W.2d 118, 122 (Tex. 1996); *Johnson v. Jernigan*, 475 P.2d 396, 399 (Okla. 1970); *Sternberger v. Marathon Oil Co.*, 894 P.2d 788, 799-800 (Kan. 1995).

6. WYO. STAT. ANN. §§ 30-5-301 to -305 (LexisNexis 2003).

7. *Id.* § 35-5-301.

8. *Id.* § 35-5-304(a)(vii).

market pipeline. "Costs of production" does not include the reasonable and actual direct costs associated with transporting the oil from the storage tanks to market or the gas from the point of entry into the market pipeline or the processing of gas in a processing plant.<sup>9</sup>

The use of the term "gathering" under the definition of "Costs of production" presents the question of whether the Wyoming Legislature intended the term to include transportation off the lease to a distant point downstream or gathering occurring in connection with the production function that takes place on the lease or unit. Since it is a cost of production that the statute seeks to define under the umbrella of "exploration, development, primary or enhanced recovery and abandonment operations," transportation many miles downstream of the terminus of the producer's facilities cannot be considered a "cost of production." Royalty owners, however, have attempted to be excused from costs they have traditionally shared in by attempting to force long distance FERC related gathering into the cost of production definition.<sup>10</sup>

The term "gathering" has different meanings in different contexts. Pipeline facilities on a lease transport oil and gas to and from lease equipment such as separators, heater treaters and dehydrators and also transport oil to storage tanks on the lease and gas to an interconnection with the pipeline facilities of the first transporter who will transport the gas off the lease. However, the term "gathering" is also used to describe the facilities of certain transporters (usually the first transporters) of natural gas to signify that these facilities are exempt from federal regulation by the FERC under § 1(b) of the Natural Gas Act (the "NGA"), 15 U.S.C. § 717(b). Section 717(b) of the NGA provides that, "The provisions of this chapter shall apply to the transportation of natural gas in interstate commerce . . . but shall not apply . . . to the production or *gathering* of natural gas."<sup>11</sup> Under the NGA, "gathering" is distinct from "production" and both are exempt from federal regulation.<sup>12</sup>

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9. *Id.* § 35-5-305(a)(vi).

10. The Wyoming Supreme Court is presently considering the meaning of the word "gathering" under title 30, chapter 5, section 305(a)(vi) of Wyoming Statute, in a case before the Wyoming Supreme Court on questions certified by the United States District Court for the District of Wyoming (J. Downes). See *Followwill et al v. Cabot Oil and Gas Corporation*, No. 02-283 (Wyo). See also WYO. STAT. ANN. § 30-5-305(a)(vi) (LexisNexis 2003).

11. 15 U.S.C. § 717(b) (2000) (emphasis added).

12. The factors that FERC considers in determining whether particular pipeline facilities constitute interstate pipeline facilities or NGA-exempt gathering facilities have changed over the years in response to changes in regulatory objectives as well as various court decisions. *Amerada Hess Corporation*, 52 F.E.R.C. ¶ 61,268, 1990 WL 1241336 (1990). As the factors have evolved, systems that were once classified as jurisdictional may be reclassified as exempt gathering and vice versa. Thus, pipeline facilities in Wyoming and elsewhere have been



The distinction between “production” gathering and “post-production” gathering or transportation is illustrated by the decision of the Interior Board of Land Appeals, *Enron Oil & Gas Co.*<sup>13</sup> The issue before the IBLA was whether Enron was required to obtain rights of way for certain pipeline systems on the lease. The Board recognized the distinction between production facilities maintained on the lease and the transportation pipeline, stating,

We believe that a reasonable dividing point between “production” and “transportation” is the point at which the lease operator completes his final processing or storage of the product or, in the case of gas, the point of delivery to the transportation pipeline. Thus, “production facilities” include an operator’s storage tanks and processing equipment, and oil and gas pipelines upstream from the operator’s tanks and equipment or, in the case of gas, upstream from the point of delivery.<sup>14</sup>

Further,

The function served by Enron’s lateral lines falls within this definition (of gathering), as they move lease production to a central accumulation point on each lease. That point . . . is the interconnection with Northwest’s gathering system, where the lines meet other lateral lines from other wells on the lease.<sup>15</sup>

Accordingly, the IBLA held that no rights of way for on-lease production facilities were required.<sup>16</sup> The IBLA specifically noted that its references to Northwest’s gathering system did not imply that it was also a “gathering line” within the meaning of the right-of-way regulations.<sup>17</sup> The IBLA clearly recognizes the distinction between on-lease gathering and transportation off the lease in pipelines that may be classified by FERC as gathering for purposes of NGA regulation.

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reclassified by FERC in both directions. For example, in 1996, FERC re-functionalized certain Wyoming facilities of Colorado Interstate Gas Company from gathering to interstate pipeline facilities. See *Colorado Interstate Gas Company*, 75 F.E.R.C. ¶ 61,325, 1996 WL 355523 (1996). Conversely, in 1997, FERC reclassified the Wyoming pipeline facilities of Western Transmission Corporation as gathering even though those facilities had been classified as an interstate pipeline since the mid 1960s. *Western Transmission Corporation*, 80 F.E.R.C. ¶ 61,194, 1997 WL 438866 (1997).

13. *Enron Oil & Gas Co.*, 122 I.B.L.A. 224 (1992).

14. *Id.* at 233.

15. *Id.* at 236.

16. *Id.* n.4.

17. *Id.*

The same issue was before the IBLA in *Phillips Petroleum Co.*<sup>18</sup> in which the issue was whether certain costs of gathering and compression were deductible in calculating royalty payments. The IBLA held that, “we set aside the Director’s decision to the extent he concluded that the costs of gathering and compression were non-deductible expenses incidental to the marketing of the gas and remand for a determination of the amount of those expenses which may be deducted as reasonable transportation costs.”<sup>19</sup>

The decision again illustrates that the “gathering and compression” label placed on a transportation function does not dictate a conclusion that such costs are nondeductible. Rather, one must look to the actual location and function of the facilities to make this determination.

The facilities commonly found in the Powder River Basin for the production of coalbed natural gas could not make application of the MMS rules more straightforward. The basic operational structure of each field is quite similar. Typically, gas produced from individual wells is gathered to one of several “central delivery points” (or “CDPs”). A CDP may serve from two to thirty wells and there are several CDPs in each field. The CDP removes free water and serves as the initial metering point by a third party. Production functions end at the CDP and gas typically leaves the producer’s control at this point. The CDP meets the classic definition of “gathering” found in 30 C.F.R. § 206.151 (“‘Gathering’ means the movement of lease production to a central accumulation and/or treatment point . . .”). After the CDP, the gas passes to a larger diameter pipeline. At this point, the gas has been delivered into a transportation pipeline. The costs for movement of the gas downstream of the CDP are transportation costs that Section 206.151 permits under the “transportation allowance.” That section allows deduction of the costs for the reasonable and actual costs incurred by the lessee for moving unprocessed gas, residue gas, or gas plant products to a point of sale or point of delivery off the lease, unit area, communitized area, or from a processing plant, excluding gathering costs.

Recent guidance by the MMS as pertaining to coalbed natural gas in the Powder River Basin has held that, at least where the BLM has approved the CDPs as the point of measurement, movement of the gas to the CDPs and the custody transfer meter constitutes gathering.<sup>20</sup> According to the MMS, gas movement beyond the custody transfer meter at the CDPs constitutes allowable transportation in the Powder River Basin of Wyoming, and

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18. *Phillips Petroleum Co.*, 109 I.B.L.A. 4 (1989).

19. *Id.* at 13.

20. Memorandum from the Minerals Management Service, United States Department of the Interior, to Mr. Gregg Henson, Assistant Controller, Devon Energy Corporation (Oct. 9, 2003) (on file with the Wyoming Law Review).



under guidance issued by the MMS in 1995 and 1996, in New Mexico as well.<sup>21</sup>

### III. THE MARKETABLE CONDITION RULE

#### *The Regulations*

In its endeavor to force the point of valuation as far down stream as possible, the MMS continues to extend the reach of the so-called "Marketable Condition Rule" ("the Rule").<sup>22</sup> Under its regulations, 30 C.F.R. § 206.152 (i), the MMS' articulation of the Rule is as follows:

The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.<sup>23</sup>

"Marketable condition," in turn, is defined under the regulations as "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."<sup>24</sup>

#### *Reclassifying Transportation Costs As "Marketing" Expenses*

"Marketable condition," the MMS asserts in 30 C.F.R. § 206.152 (i), requires the lessee to assume two kinds of costs. According to the MMS, the lessee must assume (i) such costs as are necessary to put the gas into such a condition that it is sufficiently free of impurities to be sold; and (ii) costs incurred to market the gas (or classic marketing functions).<sup>25</sup> The MMS has

21. *Id.*; Memorandum from Deputy Director, Minerals Management Service, U.S. Department of the Interior, to Associate Director for Policy and Management Improvement and Associate Director for Royalty Management, Minerals Management Service, United States Department of the Interior (Dec. 8, 1995) (on file with the Wyoming Law Review); Memorandum from Robert E. Brown, Assistant Director for Royalty Management, Mineral Management Service, United States Department of the Interior, to Operators/Payers of Coalbed Methane in the San Juan Basin (Apr. 22, 1996) (on file with the Wyoming Law Review).

22. For a discussion of the historical and theoretical underpinnings of the marketable condition rule, see Lansdown, *The Marketable Condition Rule*, 44 S. TEX. L. REV. 667 (2003).

23. 30 C.F.R. § 206.151(i) (2003).

24. 30 C.F.R. § 206.151 (2003).

25. The fact that the MMS includes classic marketing functions within the "marketable condition" rule is demonstrated by Section 6.1.5 of the Oil and Gas Payor Handbook which specifies that "market brokerage, or other marketing activities" are included as costs that the

attempted to expand the definition of costs incurred to market the gas by attempting to reclassify true transportation functions as ones that are incurred to market the gas. In so doing, the MMS departs from the historic distinction between marketing and pipeline related functions that, prior to FERC Order 636, would be part of a bundled transportation rate (including compression, dehydration, fuel use, and CO<sub>2</sub> removal) and would be part of the pipeline's rate structure and depreciation of assets.

In 2002, the D.C. Circuit addressed whether Interior could require oil and gas lessees to include their downstream marketing costs in computing royalty value. In *Independent Petroleum Ass'n of America v. DeWitt*,<sup>26</sup> the D.C. Circuit held that it was not unreasonable for Interior to require gas producers to make marketing services non-deductible. In upholding the regulations, the court found that marketing services have historically not been deductible from gross proceeds, and noted that the only allowable deductions have been for the costs of transporting and processing gas.<sup>27</sup> The court stated the Interior has repeatedly distinguished between transportation services and marketing services in deciding what lessees can deduct from gross proceeds, but had improperly treated some true transportation costs as marketing expenses.<sup>28</sup>

Before the issue arrived before the D.C. Circuit, the district court was less forgiving of the MMS:

The court also finds that MMS' distinctions between what it now labels as "marketing" costs and "transportation" costs are not reasonably suggested by the text of the provisions governing allowances. Moreover, the arbitrary distinctions that MMS draws between the two costs result in inconsistencies, which MMS fails to explain in the Rule. *Cf. Independent Petroleum v. Babbitt*, 92 F.3d at 1260. For example, under the Rule, MMS permits an allowance for intra-hub wheeling costs, reasoning that such costs are "actual" costs of transportation. At the same time, however, MMS rejects the deductibility of intra-hub transfer fees on the basis that they are not "actual" costs, merely "administrative" costs of transportation. Similarly, MMS provides no reasoned basis—aside from conclusory statements—for disallowing aggregator/marketer fees. . . . MMS also disallows a deduction for firm demand charges for unused capacity, stating that it does not "consider the amount paid for unused

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lessee is required to incur to place lease production into marketable condition. The MMS' choice of words is revealing as it shows that it understands what true marketing functions are.

26. *Independent Petroleum Ass'n of America v. DeWitt*, 279 F.3d 1036 (D.C. Cir. 2002).

27. *Id.* at 1037-38.

28. *Id.* at 1041.



capacity as a transportation cost.” 62 Fed.Reg. 65757. MMS simply asserts that because this portion of capacity was not ultimately used to move the gas, it is not an “actual” cost of transporting the gas.<sup>29</sup>

The district court summed up what MMS had done in the following way: “In short, MMS simply labels certain costs marketing and certain costs transportation, without offering any consistent or principled justification for why a particular label applies.”<sup>30</sup>

Though the D.C. Circuit did not agree with the district court straight down the line, the D.C. Circuit did agree that MMS had simply placed the “marketing” label on some costs that were actual transportation functions.<sup>31</sup> The court found that before FERC Order 636, marketing costs would have been bundled with transportation costs, making precise separation of the two administratively troublesome, if not impossible.<sup>32</sup> Once Order 636 unbundled rates, Interior could identify “nonallowable costs of marketing” to which Interior could rigorously employ its “marketing” and transportation classifications.<sup>33</sup> This did not mean, however, that MMS always made meaningful distinctions between true “marketing” costs and transportation costs. *DeWitt* stands for the proposition, as one would expect, that the mere labeling of costs is not enough.

Unfortunately, MMS has used Order 636 as not only an opportunity to separate marketing costs from transportation costs, but as a device to reclassify true transportation costs like compression, downstream dehydration, and CO<sub>2</sub> removal as “marketing” costs. As later discussion will demonstrate, MMS’ ambition to broaden the scope of what was reasonably meant by “marketing costs” has forced MMS to make meaningless distinctions in an attempt to reconcile its conflicting positions. For example, in the Powder River Basin, the MMS has argued that that booster compression prior to CO<sub>2</sub> removal is allowable as transportation, but re-compression after CO<sub>2</sub> removal is not allowable because it is “marketing.”

The MMS’ distinctions between what it now labels as “marketing” costs and what it is willing to label as “transportation” costs are not supported by the text of its rules. As an illustration, in the positions under review in *DeWitt*, the MMS treated marketer fees in the same fashion as firm transportation demand charges.

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29. Independent Petroleum Association of America v. Armstrong, 91 F. Supp. 2d 117, 126-27 (D.D.C. 2000).

30. *Id.* at 127.

31. *DeWitt*, 279 F.3d at 1042.

32. *Id.*

33. *Id.*

The *DeWitt* court held that it is the nature of the cost—i.e., whether it is a true transportation cost, processing cost, or marketing cost—that determines whether it is deductible, not where or by whom that cost is incurred. Despite this ruling, the MMS has denied costs by relying on the fiction that if CO<sub>2</sub> removal had occurred at or near the field, no compression would be needed.

### *Reclassifying Transportation Costs In The Powder River Basin*

For coalbed natural gas produced in the Powder River Basin, the MMS continues its push to reclassify transportation costs as “marketing” costs simply by changing the label. The MMS argues that coalbed natural gas is marketable at or near the well for purposes of the transportation allowance, but is not marketable for some down stream transportation functions like some compression (but not all compression), dehydration, and CO<sub>2</sub> removal.

In truth, coalbed natural gas is in marketable condition at the well as established by the fact that it is often sold at or near the well in the Powder River Basin. The quality of the gas does not change when the gas is marketed further downstream. In the Powder River Basin, a substantial quantity of the gas is transported on a FERC regulated pipeline (with no CO<sub>2</sub> removal) of approximately the same length as a parallel unregulated pipeline on which there is CO<sub>2</sub> removal. Marketing the gas at a distance from the well has been used by the MMS as a pretext for treating the gas as not marketable at or near the well for some but not all purposes.

Guidance issued by the MMS on October 9, 2003 relating to Powder River Basin coalbed natural gas has advised that not all functions after the CDPs constitute deductible transportation costs because, in some cases, further dehydration and CO<sub>2</sub> removal may be performed after gathering has been completed.<sup>34</sup> In this guidance memorandum, the MMS has taken the position that processes related to putting the gas into marketable condition include compression, dehydration, and CO<sub>2</sub> removal. The fact that the gas has been gathered does not necessarily imply, says the MMS, that the gas is otherwise in marketable condition. As a result, the MMS allowed all movement of the gas beyond the CDP to be deducted as transportation, but did not allow the deduction of some compression costs and costs of dehydration and CO<sub>2</sub> removal.

In the October 9, 2003 guidance memorandum, MMS focuses its marketable condition analysis on what is required to fulfill the producer’s contract to sell the gas. To the extent that it is essential that the gas be processed, compressed, and dehydrated for delivery to the pipeline, the MMS

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34. Memorandum from the Minerals Management Service, *supra* note 20.



will attempt to characterize these costs as ones necessary to sell the gas rather than costs associated with the transportation function.

In characterizing which costs will be treated as transportation costs and which will not, the October 9, 2003 guidance indicates that screw and reciprocating compressor costs will not be allowed as part of the transportation allowance, but the costs associated with booster compression on a particularly long length of pipeline will be treated as transportation costs. While several cases have held that compression necessary to meet pipeline delivery requirements are part of putting the gas into marketable condition,<sup>35</sup> there is no real functional difference between the screw and reciprocating compressors and booster compression and the MMS strains to justify why certain compression is not necessary for transportation while other compression is necessary to transport the gas.

On December 8, 2003, Devon asked MMS to reconsider its October 9, 2003 guidance. The MMS denied Devon's request.<sup>36</sup> Rather than moderating its approach, MMS extended its application of the marketable condition rule to disallow fuel use on the very lines it treated as allowable transportation.<sup>37</sup>

### *The MMS Flip-Flop*

The October 9, 2003 guidance reverses advice the MMS gave in 1995 to producers with the same kind of coalbed natural gas facilities as those found in the Powder River Basin. In a "Compression Guidance" memorandum dated December 8, 1995,<sup>38</sup> the MMS found that cost of compression performed after meeting the delivery requirement for pressure of the pipeline immediately downstream of the BLM or MMS measurement point is an allowable deduction from MMS royalties as part of the cost of transportation.<sup>39</sup>

In "Coalbed Methane Valuation and Reporting Guidelines" dated December 7, 1995,<sup>40</sup> growing out of a guidance request of coalbed natural gas producers in the San Juan Basin, the MMS found that, "Compression costs incurred to enhance production are not allowable. To the extent that a producer can demonstrate that all or a portion of the compression occurring

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35. See, e.g., *California Co. v. Udall*, 296 F.2d 384 (D.C. Cir. 1961).

36. Letter from the Minerals Management Service, United States Department of the Interior, to Mr. Gregg Henson, Assistant Controller, Devon Energy Corporation (March 19, 2004) (on file with the Wyoming Law Review).

37. *Id.* at 2-6.

38. Memorandum from Deputy Director, *supra* note 21.

39. *Id.*

40. Letter from Minerals Management Service, *supra* note 36.

at the CDP [central delivery point] is necessary for transportation, that portion will be allowable as part of transportation."<sup>41</sup>

The MMS repeated this advice in an April 22, 1996 guidance memorandum prepared for producers in New Mexico's San Juan Basin.<sup>42</sup> The April 22, 1996 guidance stated that "costs for compression occurring downstream of the royalty measurement point, to the extent the compression was necessary for transportation," were included as part of transportation related costs.<sup>43</sup> The April 22, 1996 guidance likewise found that costs of dehydration, of the kind disallowed under the October 9, 2003 advice pertaining to the Powder River Basin, were considered part of the transportation allowance.<sup>44</sup>

The MMS' October 9, 2003 guidance in the Powder River Basin represents a flip-flop from its earlier position taken in the San Juan Basin. Compression and dehydration that was part of transportation in the past has suddenly become non-allowable under the same set of regulations and decisions. Part of the rationale for the change comes at page 25 of the October 9, 2003 guidance where the MMS makes a self-contradicting statement so revealing of its attempt to make anything and everything a marketing function at its will. It said that "simply because compression may be necessary to make the gas *transportable* does not mean that the compression is part of transportation."<sup>45</sup>

The MMS found that, in some circumstances, while some compression at or near the well could be considered transportation, the screw compressor might be necessary to *produce* the gas. This statement is not accurate. While the CDP does serve a production-related function by taking free water from the flow of the gas, allowing the gas to flow under natural pressure, compression downstream of the CDP does not serve a production-related function but is part of the transportation function.

### *Taking Stock of Shell and Torch*

In 1994, Shell Offshore, Inc., asked the MMS to confirm that Shell was entitled to deduct its FERC approved tariff as the non-arm's length transportation allowance for the movement of crude from an offshore federal lease.<sup>46</sup> MMS denied Shell's request to use the FERC tariff because Shell

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41. Memorandum from the Minerals Management Service, *supra* note 20.

42. Memorandum from Robert E. Brown, *supra* note 21.

43. *Id.*

44. *Id.*

45. Memorandum from the Minerals Management Service, *supra* note 21 (emphasis added).

46. *Shell Offshore, Inc. v. Babbitt*, 61 F. Supp. 2d 520 (W.D. La. 1999), *aff'd in part, rev'd in part*, 238 F.3d 622 (5th Cir. 2001).



did not have a determination from FERC that the pipeline fell within FERC jurisdiction.<sup>47</sup> An administrative appeal followed. The final administrative decision upheld the denial of the use of the FERC tariff on the same grounds. Both the agency's initial determination and the final agency action departed from the longstanding MMS practice of not requiring an affirmative jurisdictional statement from FERC to permit use of a FERC approved tariff.<sup>48</sup>

The district court held that Interior could not deviate from its established policy of not requiring a jurisdictional finding without initiating formal notice and comment rulemaking proceeding under the Administrative Procedure Act.<sup>49</sup> On appeal from the district court, the Fifth Circuit agreed that Interior could not condition a lessee's use of a FERC tariff on a FERC jurisdictional determination without first going through notice and comment rulemaking.<sup>50</sup> From this case and its progeny, the MMS was placed on notice that it cannot switch from a long held interpretation of its regulations to a new one without amending its rules through formal notice and comment rulemaking.<sup>51</sup>

In *Torch Operating Co. v. Babbitt*,<sup>52</sup> the District Court for the District of Columbia addressed the same issue the Fifth Circuit decided in *Shell*. The *Torch* court agreed with the Fifth Circuit's ruling in *Shell* that the MMS could not change its established interpretation of its regulations without first going through notice and comment rulemaking.<sup>53</sup>

The *Shell* and *Torch* cases have obvious implications for the MMS' handling of coalbed natural gas royalty valuation. In 1995 and 1996, the MMS put producers on notice that transportation-related compression and dehydration after the CDP were allowable costs of transportation. The MMS' interpretation of its rules stood for nearly eight years. MMS manifested its intent for producers to rely on its advice. Then, in October of 2003, the MMS had a change of heart. It now wishes to repudiate the 1995 and 1996 guidance that it gave producers. The *Shell* and *Torch* cases make plain that an agency may not flip-flop on established interpretation of its rules. If it wishes to change how it will apply its rules, MMS must submit the change to notice and comment rulemaking. Due process demands no less.

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47. *Id.*

48. *Id.*

49. *Id.* at 529.

50. *Shell Offshore, Inc. v. Babbitt*, 238 F.3d 622, 629-30 (5th Cir. 2001).

51. *Id.* at 630.

52. *Torch Operating Co. v. Babbitt*, 172 F. Supp. 2d 113 (D.D.C. 2001).

53. *Id.* at 128.

#### IV. CONCLUSION

The MMS' treatment of post-production costs in the Powder River Basin represents its continuing effort to find new ways to deny allowances without undertaking the long and arduous formal rulemaking process. By avoiding the rulemaking process, MMS has sought to retroactively change its rules. The result has been that MMS has made arbitrary distinctions not supported by its rules simply by labeling true transportation costs as "marketing" expenses.

Realizing that the MMS has constantly sought to move the point of royalty valuation as far downstream as possible suggests the following analytical framework for these issues: First, one should examine the statutory authority for the rule in an effort to determine whether the agency has exceeded its statutory authority in adopting the rule. The second question is whether the agency's interpretation of the rule is in keeping with the original intent of the rule. In this regard the Congressional Record and internal agency memoranda are useful in determining intent. The third question is whether the agency has changed its interpretation of the rule without undertaking formal notice and comment rulemaking. The last question, as a factual matter, is whether the MMS has applied the rules according to the location and function of the facilities in question without regard to what the agency may simply want to label as "marketing."