EXXON MOBIL CORPORATION P.O. BOX 2443 HOUSTON, TX 77210-2443,	§ §	STATE OF ALABAMA DEPARTMENT OF REVENUE ADMINISTRATIVE LAW DIVISION
Taxpayer,	§	DOCKET NOS. MISC. 03-141 MISC. 03-281
v.	§	
STATE OF ALABAMA DEPARTMENT OF REVENUE.	§	

FINAL ORDER

These consolidated appeals involve two denied petitions for refund of oil and gas privilege and production ("severance") tax filed by Exxon Mobil Corporation ("Exxon") for January 1992 through December 1996 and March 1997 through December 2000; and a final assessment of severance tax entered by the Revenue Department against Exxon for January 1992 through December 1996. The dispute involves the taxable wellhead value of gas produced by Exxon during the subject periods at three offshore fields in Mobile Bay, and also at two onshore wells in Escambia County, Alabama.

The parties agreed that because of the complexity of the facts and issues involved, the case should be bifurcated and heard in two parts. Accordingly, a Stage One hearing was conducted over a seven day period in June 2004 for the purpose of determining (1) the point of production at which the taxable value of the gas in issue must be calculated, and (2) what post-production costs or expenses incurred by Exxon can be deducted in determining wellhead value under the workback method. Conrad Armbrecht and Duane Graham represented Exxon. Chief Counsel Henry Chappell and Assistant Counsel John Breckenridge represented the Department.

The Administrative Law Division entered an Opinion and Preliminary Order (Stage One) on February 8, 2006 which identified the point of production, the various deductions that must be allowed under the workback method, and how those deductions should be computed.

A Stage Two hearing was conducted from October 30 through November 1, 2006. Conrad Armbrecht and Duane Graham again represented Exxon. Chief Counsel Henry Chappell and Assistant Counsel John Breckenridge again represented the Department. The purpose of the Stage Two hearing was for the parties to present evidence from which Exxon's liabilities for the periods, and any resulting refunds due or additional taxes owed by Exxon for the periods, could be calculated. Additional evidence was also submitted concerning two as yet undecided issues – the royalty allocation and the take-in-kind issues. The parties also submitted a joint stipulation, with exhibits, by which they agreed that the dollar amounts, volumes, and other numbers shown on the exhibits were the correct amounts, volumes, and other numbers to be used in making the final tax computations.

The Administrative Law Division entered an Opinion and Preliminary Order (Stage Two) on August 2, 2007 which addressed the remaining substantive issues and also confirmed various Stage One findings concerning the workback method. The Stage Two Order also directed Exxon to recalculate its liabilities for the periods in issue based on the findings and holdings in the Stage Two Order. Exxon has done so.

Based on the stipulated facts and the facts submitted at the Stage One and Stage Two hearings, and applying the legal findings and conclusions as stated in the Stage One and Stage Two Orders, I find that Exxon overpaid its Alabama severance tax for the periods in issue. The severance tax final assessment for the period January 1992 through December 1996 is accordingly voided. Exxon is due refunds as follows:

1. Mobile Bay production for October 1993 through December 1996 of $11,122,161.97, plus interest of $9,619,560.66 through December 31, 2006.

2. Mobile Bay and Miocene production for March 1997 through December 2000 of $4,967,372.15, plus interest of $2,493,370.08 through December 31, 2006.

3. Big Escambia Creek production for January 1992 through December 2000 of $6,184,670.58, plus interest of $5,213,314.34 through December 31, 2006.

4. Little Escambia Creek (Jay) production for January 1992 through December 2000 of $703,658.32, plus interest of $582,767.47 through December 31, 2006.

5. An additional refund of $86,394.02, plus interest of $110,664.63 through December 31, 2006.

Exxon has requested that it should be allowed to apply the refunds due as a credit for any subsequent severance tax it may owe, citing Code of Ala. 1975, §40-2A-7(c)(4). That statute does not, however, give a taxpayer the option of requiring the Department to apply a refund due as a credit against a future liability of the taxpayer. Rather, §40-2A-7(c)(4) only allows the Department the option of offsetting any refund due to satisfy any current outstanding tax liability of the taxpayer. The Department may, however, agree to Exxon's request.

This has been a complicated and contentious case for various reasons. The primary problem, however, is that Alabama has no statutory or case law guidelines concerning the workback method.

Alabama statutory law does not address or even refer to the workback method. The Alabama Supreme Court approved the Department's use of the method in *Ex parte*

State of Alabama (In re State of Alabama v. Phillips Petroleum Co.), 638 So.2d 886 (Ala. 1992). The Court also broadly stated in *Phillips Petroleum* that all "costs of transportation, processing, and treatment" of the product should be allowed. *Phillips Petroleum*, 638 So.2d at 888. Unfortunately, neither that Court nor the Alabama Court of Civil Appeals has ever addressed the issue of exactly what costs should be allowed, and how those costs should be computed.

As discussed at length in the Stage One and Stage Two Orders, the Department's position is that only those costs directly incurred in physically processing and treating the oil or gas should be allowed. That position is, however, contrary to the Department's own workback regulation, Reg. 810-8-6-.01, which allows various indirect costs such as depreciation, return on investment, insurance, marketing expenses, and administrative overhead, to name only a few.[1]

The Department's position is also contrary to the theoretical rationale for using the method. The theory behind the workback method is that the fair market value of the raw product at the wellhead can be determined by starting with the sales price of the refined product and then deducting all costs necessarily incurred in bringing the product from the wellhead to the point of sale. All costs that a producer/processor is required to incur must be allowed because those costs affect the value of the product at the

[1] Reg. 810-8-6-.01 first broadly defines "allowed costs" as "[t]he costs incurred to bring the oil or gas to the point of delivery or first market transaction including, but not limited to, gathering (including gathering prior to separation), transporting, dehydrating, compressing, treating, conditioning, cleansing, stabilizing, processing and delivering." See, subparagraph (2)(a). The regulation later addresses ten specific costs. See, subparagraph (6)(b). Unfortunately, it does not address some costs that even the Department concedes are allowed, and the regulation is also vague and confusing concerning some of the costs that are discussed. See generally, Stage One Order at 10. Consequently, the regulation is not of much help in determining how the workback method should be applied.

wellhead. The following from the Stage One Order bears repeating:

> The goal of the workback method is to arrive at "an amount approximating market value" at the wellhead. *Phillips Petroleum*, 638 So.2d at 889. Wellhead value is what a willing buyer would pay a willing seller for the unrefined product at the wellhead. A Department expert, John Bower, testified in substance that a prospective buyer, in deciding what to pay for unrefined gas at the wellhead, must consider all costs that would be incurred in bringing the refined product to market. (R. 1630 – 1635) Bower gave essentially the same testimony in *BP America*. Relying in part on that testimony, the Administrative Law Division held in *BP America* as follows:
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>> The workback method should "result in an amount *approximating* market value." *Phillips Petroleum*, 638 So.2d at 889. Market value is determined by what a willing buyer would pay a willing seller. A Department expert testified that if a prospective buyer was determining what to pay for raw gas at the wellhead, the buyer would consider all costs necessarily incurred in bringing the processed gas to the point of sale. (R. 995 – 999) It thus follows that for workback purposes, all costs necessarily incurred from the wellhead to the point of sale should be allowed. Those costs would include all direct processing costs, and also all "indirect" costs such as water gathering and disposal that a producer necessarily incurs and must pay as a direct result of processing the gas.
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> *BP America*, at 40.
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> A post-production expense or cost must be allowed if it affects the value of the unrefined oil or gas at the wellhead. As discussed, any costs necessarily incurred in bringing the product from the wellhead to the market must be considered by a prospective buyer, and thus affects the wellhead value of the product. Those costs include not only the "direct" costs of physically transporting, treating, and processing the product, but also the various "indirect" costs that are necessarily incurred or result from those activities. (footnote omitted) Department expert Bower testified that anyone buying unrefined Mobile Bay gas at the wellhead would have to consider the cost of the janitors, cooks, and technicians on the platforms, among other costs. (R. 1632 – 1634) Those and other indirect costs must be allowed as workback deductions, because, according to Bower, "[a]ll of those functions are required." (R. 1634)

Stage One Order at 20 – 22.

The Alabama Legislature may, of course, enact legislation that codifies the workback method, what costs should be allowed, and how those costs should be computed. In that case, the Legislature could see fit to not allow or limit various costs necessarily incurred in processing oil or gas, and it could also allow some items that otherwise may not be deductible.[2] The Department would then have statutory guidelines, and could promulgate regulations expounding on, but not contrary to, those guidelines.

But unless and until the Legislature acts, the Department, if it chooses to employ the workback method, must allow those direct and indirect gathering, processing, treatment, and other costs that a processor must pay and that have a bearing on the wellhead value of the product.[3] Only then would the result be "an amount approximating market value." *Phillips Petroleum*, 638 So.2d at 889.

The factual and legal findings and conclusions in the Stage One and Stage Two Orders are incorporated into and made a part of this Final Order. Judgment is entered as indicated herein. Additional interest is also due from January 1, 2007 on the refunds due Exxon. Code of Ala. 1975, §40-1-44(b)(1).

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[2] For example, the Department for some reason currently allows a 5 percent depreciation deduction and an 11 percent return on investment deduction. See, Reg. 810-8-6-.01(6)(b)1. and 2. I question whether those items should be deductions under the workback method for the reasons explained in the Stage One Order at 22, n. 9. Allowing depreciation and ROI may also result in a producer making a monthly operating profit on the sale of gas but showing a loss under the workback method. See, Stage One Order at 36, 37. In any case, the Legislature, if it chooses to do so, could allow or not allow those items as deductions, as it deemed appropriate.

[3] The Legislature may also change the severance tax from a value-based to a volume-based tax. That would eliminate the need to use the workback and any other valuation method, and would greatly simplify the administration of the tax for both the Department and producers.

This Final Order may be appealed to circuit court within 30 days pursuant to Code of Ala. 1975, §40-2A-9(g).

Entered September 13, 2007.

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BILL THOMPSON
Chief Administrative Law Judge

bt:dr
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