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

OPINION AND PRELIMINARY ORDER
(STAGE ONE)

Exxon Mobil Corporation ("Exxon") petitioned the Revenue Department in July 2000 for a refund of oil and gas privilege and production ("severance") tax for January 1992 through December 1996. Exxon filed another severance tax refund petition in April 2001 concerning March 1997 through December 2000. Both petitions were deemed denied by operation of law. Exxon appealed both denied petitions to the Administrative Law Division pursuant to Code of Ala. 1975, §40-2A-7(c)(5)a.

The Department subsequently assessed Exxon for severance tax for January 1992 through December 1996.[1] Exxon appealed the final assessment to the Administrative Law Division pursuant to Code of Ala. 1975, §40-2A-7(b)(5)a. The appeals were consolidated, and a hearing was conducted on June 22 through June 25 and June 28 through June 30, 2004. Conrad Armbrecht and Duane Graham represented Exxon. Department Chief Counsel Henry Chappell and Assistant Counsel

[1] The final assessment resulted from a Department audit of Exxon that began in 1997. The Department issued its initial audit report in August 1998 indicating that Exxon owed approximately $8 million in additional severance tax, plus interest. The Department issued revised audit reports in February and August 2000 and March 2003, which showed varying amounts due. Finally, the Department submitted a "final" audit report during the June 2004 hearing claiming that Exxon owed approximately $12.6 million for the January 1992 through December 1996 period.

John Breckenridge represented the Department.

ISSUES

This case involves Exxon's Alabama severance tax liability on gas produced by Exxon at three offshore fields in Mobile Bay during the periods in issue, and also at two onshore fields in Escambia County, Alabama, i.e., the Big Escambia Creek ("BEC") field and the Jay/Little Escambia Creek ("LEC") field. The dispute concerns how the taxable value of Exxon's gas should be computed.

Alabama severance tax is levied on the gross value of unrefined oil or gas at the point of production. Code of Ala. 1975, §§40-20-2(a)(1) and 9-17-25. The parties agree that the "workback method" should be used to determine the taxable value of the gas in issue. Value is determined under the workback method by taking the first arm's-length sale price of the refined oil or gas, and then working back to the value of the unrefined product at the point of production by deducting all post-production costs, i.e., the "costs of transportation, processing and treatment," incurred in bringing the oil or gas to market. *Ex parte State of Alabama (In re State of Alabama v. Phillips Petroleum Co.)*, 638 So.2d 886, 888 (Ala. 1992).

The parties agreed before the June 2004 hearing that because of the complexity of the issues involved, the case should be bifurcated and heard in two parts. The first hearing, which was the hearing conducted in June 2004, was for the purpose of identifying the costs or expenses incurred by Exxon that should be allowed under the workback method. This Order addresses those issues. A subsequent hearing will be conducted in due course for the purpose of determining the dollar amounts of the allowable deductions, and any resulting refund or additional tax due, as the case may be.

The disputed issues to be addressed in this Stage One Order are (1) where is the point of production at which the taxable value of the unrefined gas must be determined, and (2) what post-production costs or expenses incurred by Exxon can be deducted under the workback method, and how should those costs or expenses be computed.

FACTS

An overview of Exxon's Mobile Bay, BEC, and LEC operations is set out below. Additional facts are also stated as necessary in the analysis of the disputed issues.

The Mobile Bay Operation.

Exxon produced gas from wells in three offshore fields in Mobile Bay and surrounding Alabama waters during the periods in issue. Exxon drilled the wells from 1982 through 1993, but did not begin producing gas from the wells until October 1993. As discussed below, the Mobile Bay gas is processed or treated at three central platforms in Mobile Bay, and also at Exxon's onshore facility in Mobile County, Alabama, where the refined gas is sold.

The gas in Mobile Bay contains hydrogen sulfide, carbon dioxide, and various contaminants and impurities. The gas rises to the surface through the well bore, and flows through the wellhead apparatus at the top of the well. Above the wellhead is a "Christmas tree," which is a series of valves that control the flow of the gas stream from the wellhead to the gathering pipes.

Each offshore well is connected to or surrounded by an above-water structure known as a well template. The template allows Exxon's employees access to the wellhead and Christmas tree. It also supports a cooler and injection equipment, which are discussed below, and also the gathering pipes through which the gas is transported from the wellhead to a central platform located in each of the three offshore fields.

Various substances are injected into the gas stream at or immediately after the wellhead to prevent the downstream gathering pipes and equipment from clogging or plugging. Specifically, methanol is injected to prevent hydrates from forming. Dilution water is injected to prevent salt deposits from forming. A chemical scale inhibitor is added to prevent scales or solid compounds from forming. Finally, liquid diesel is injected to prevent diamondoids in the gas stream from solidifying and plugging the downstream pipes and equipment. Exxon transports the various liquids in pipes from onshore to the platforms and then to the templates, where the substances are injected into the flowlines.

The Mobile Bay gas is extremely hot when severed, and must be cooled to prevent pipe damage and to facilitate further treatment downstream. Consequently, after the gas enters the gathering line, it passes through a cooler on the well template. The cooled gas is then transported from the template through the gathering pipes to the central platform. If a well is located near a central platform, it is connected to the platform by a bridge. The gathering or flow lines that transport the gas from the close-proximity wells are above water, and are made of regular carbon steel. The gas from the remote wells is transported in underwater lines which, for safety and environmental reasons, are constructed of expensive nickel-based alloy.

The gas from the wells is metered as it enters the central platform. The gas is then commingled and passed through a cooler on the platform. It is then run through a platform separator, which separates the gas from the liquids, including the diesel that contains the dissolved diamondoids. The separated gas flows out of a pipe on the top of the separator, and is run through a post-separation meter. The liquids settle in the bottom of the separator.

The gas that leaves the separator still contains some water vapor and vaporized diamondoids, and also the hydrogen sulfide and carbon dioxide that was originally in the gas stream. After the post-separation meter, more diamondoids are removed in a diamondoid absorption or diesel contactor. The gas is then dehydrated when it passes through a triethylene glycol or TEG contactor. The gas then leaves the central platform, is commingled with the gas from the other two platforms, and is transported to Exxon’s onshore treatment facility.

The liquids that settle in the platform separator must also be transported onshore for further treatment and disposal. However, the residual gas in the liquids is first removed by running the liquids through a flash tank on the platform. The recovered gas is compressed and commingled with the main gas stream going to the onshore facility. The remaining liquids are transported onshore in pipes that run parallel to the main gas line.

Each central platform has three gas-operated generators that produce the electricity needed to operate the equipment on the platforms and related templates. Exxon uses its own fuel gas, or gas produced in the offshore fields, to operate the generators. Fuel gas is also used to operate the TEG dehydration units on the platforms. Exxon has dedicated lines in which the fuel gas is delivered from its onshore facility to the central platforms.

One of the central platforms contains living quarters and dining facilities where the Exxon employees live while on duty in Mobile Bay. The employees perform various maintenance, monitoring, and repair work on the platforms and templates. They also spend a small amount of time on well-related matters.

Once the gas reaches the onshore facility, it passes through an inlet liquids separator that removes any liquids that may have formed when the gas was being transported onshore. The hydrogen sulfide and about half of the carbon dioxide is then removed when the gas passes through an amine contactor. The gas is dehydrated again after it leaves the amine contactor, and is sold at the plant tailgate.

The hydrogen sulfide removed from the gas must be disposed of, but is too toxic to be vented and cannot be efficiently incinerated. Consequently, Exxon converts it into liquid, molten sulfur that it sells to chemical or fertilizer companies.

As discussed, the liquids that are captured in the platform separators are also transported to the onshore facility. They are passed through an inlet liquids separator at the facility, which removes the remaining gas from the liquids. That gas is compressed and commingled with the other gas from the offshore wells.

The remaining liquids are a combination of water produced with the gas and hydrocarbon liquids. The produced water is separated and commingled with the plant wastewater, and is disposed of by subsurface injection at the plant site. The remaining hydrocarbon liquids are further treated so that the remaining hydrogen sulfide and any "light ends," or volatile hydrocarbon components, are removed. The remaining substance is a low grade product known as stripped diesel. Exxon initially sold all of the stripped diesel, but began reusing most of the stripped diesel in its offshore operations in 1998.

Exxon operates the onshore facility using electricity from three gas turbine generators and one steam generator. Exxon uses its own fuel gas to operate the gas generators. The steam generator is powered by steam produced by the facility.

The steam generator operates continuously because the plant is continuously producing steam. The plant could operate on the electricity provided by the steam generator and more than one but less than two of the gas generators working at 100 percent capacity. However, Exxon always operates at least two of the gas generators at full capacity for efficiency purposes. It uses the electricity it needs to operate the facility, and sells the excess electricity to Alabama Power Company. The third gas generator is maintained as a spare in case one of the other gas generators fails or is down for repairs or maintenance. Exxon operates all three gas generators from June through September because it can sell the excess electricity to Alabama Power at a favorable price.

The Big Escambia Creek Operation.

The BEC field is located in Escambia County, Alabama. The BEC gas also contains hydrogen sulfide and carbon dioxide. The gas is transported in individual flowlines from the wells to a plant located in the BEC field. The gas is then treated substantially the same as the gas in Mobile Bay. That is, it is commingled and fed into a separator to remove excess liquids. The hydrogen sulfide and some of the carbon dioxide is removed in an amine system. The removed hydrogen sulfide is converted to sulfur and sold. The gas is then dehydrated and sold at the plant tailgate. The plant wastewater is commingled with the water produced in the field, and is disposed of in underground wells at the plant.

The BEC field gas also contains natural gas liquids ("NGLs") such as propane and butane. The BEC plant has a facility at which the NGLs are removed from the gas, liquefied, and then sold.

Exxon uses fuel gas processed at the BEC plant to operate some of the equipment in the plant. Exxon also has small steam generators that provide some of the electricity used in the plant. However, the majority of the plant electricity is purchased from Alabama Power Company.

The Jay/Little Escambia Creek Operation.

The Jay/LEC field actually consists of two fields. The Jay field is in Florida. The LEC field is in Escambia County, Alabama. The product severed in the Jay/LEC field is processed or treated at the St. Regis plant in Florida, which is approximately two and a half miles from Alabama.

The LEC gas also contains hydrogen sulfide and carbon monoxide. As at the Mobile Bay and BEC wells, there are no wellhead separators at the LEC wells. The raw product flows from the wells either directly to the St. Regis plant or to satellite gathering points where it is commingled with the product from other wells and transported to the plant. The gas is then processed at the St. Regis facility in much the same way as the gas at the Mobile Bay and BEC facilities.

Exxon injects nitrogen and water into the Jay/LEC field to increase or facilitate production. The nitrogen and water increases the underground pressure, which causes the product to flow to the wells. Exxon must remove the injected nitrogen before the refined product can be sold. It does so using a nitrogen rejection unit at the St. Regis facility.

THE WORKBACK METHOD IN ALABAMA

The workback method for valuing oil and gas is not defined or even referred to in Alabama's oil and gas severance tax statutes. Nonetheless, the Department began using the workback method in the mid-1980's.

The Administrative Law Division decided several cases in the late 1980's concerning the workback method. Two of those cases were appealed to Alabama's appellate courts. The courts ultimately decided both cases on procedural or jurisdictional grounds, and did not address the issue of what specific costs are allowable under the method. See, *State, Dept. of Rev. v. Clay J. Calhoun*, 792 So.2d 373 (Ala. Civ. App. 1998), and *State v. Petro-Lewis Corp.*, 534 So.2d 302 (Ala. Civ. App. 1988).

The Alabama Supreme Court first approved the Department's use of the workback method in *Phillips Petroleum* in 1992. As discussed, the Court broadly stated in *Phillips Petroleum* that all "costs of transportation, processing and treatment" of oil or gas could be deducted under the workback method. *Phillips Petroleum*, 638 So.2d at 888. Unfortunately, because the issue was not in dispute, the Supreme Court did not elaborate concerning the specific costs or deductions that should be allowed, and neither that Court nor the Alabama Court of Civil Appeals has since addressed the issue.

The Tuscaloosa County Circuit Court applied the workback method in 1993 in *Black Warrior Methane Corp. v. State of Alabama*, Civ. Action CV-92-1423. That Court reiterated that all expenses incurred in transporting, processing, and treating the coal bed methane gas in issue should be allowed. The Court also noted that the Department had failed to promulgate regulations concerning the workback method. The Department thereafter drafted a workback regulation with input from industry representatives. The result, Reg. 810-8-6-.01, became effective in April 1997.

Dept. Reg. 810-8-6-.01 attempts to identify the various workback deductions and how they should be computed. It first lists the "allowed costs" in paragraph (2)(a). It then discusses in varying detail certain other "allowed costs" in paragraph (6)(b). Unfortunately, several provisions in paragraph (6)(b) are vague, and have been in issue in two recent appeals before the Administrative Law Division, *Torch Operating Co. v. State of Alabama*, Misc. 02-590 (Admin. Law Div. 7/31/03) and *BP America Production Co. v. State of Alabama*, Misc. 02-595 (Admin. Law Div. O.P.O. 5/12/05).[2] Reg. 810-8-6-.01 and the *Torch Operating* and *BP America* decisions are discussed in more detail below.

ANALYSIS

Alabama's severance taxes are measured on the value of unrefined "oil or gas at the point of production." Sections 40-20-2(a)(1) and 9-17-25. The first step in the workback method is to identify the point of production at which the raw product must be valued. The second step is to determine what post-production costs should be allowed, and how those allowable costs should be computed.

Issue (1). The Point of Production.

Exxon argues that the point of production at which the gas must be valued is at

[2] *Torch Operating* is currently on appeal before the Tuscaloosa County Circuit Court, CV 2004-91. *BP America* is on appeal in Montgomery County Circuit Court, CV-05-2906-TH. The *Torch Operating* and *BP America* decisions, and all other Administrative Law Division cases cited herein, can be accessed on the Department's website, www.revenue.alabama.gov, under "ALJ Rulings."

the top of the well bore at or about the wellhead apparatus and before the gas enters the gathering lines. The Department contends that the point of production is not at the wellhead at the top of the well, but rather at the first meter after separation at which the gas can be accurately measured and analyzed. The Department thus argues that the point of production for the Mobile Bay gas is the meter after the platform separator on the central platforms, and that the point of production for the BEC and LEC gas is the post-separation meter at the respective plants. Exxon's position is correct.

"Point of production" is not specifically defined or identified by Alabama law. However, Alabama's severance tax statutes, when read together, clearly establish that the point of production for severance tax valuation purposes is at or near the wellhead apparatus at the top of the well bore where the oil or gas is severed or removed from the soil or waters of Alabama.

To begin, severance tax is levied on every person "in the business of producing or severing oil or gas" in Alabama. Section 40-20-2(a)(1). The words "producing or severing," as used in §40-20-2(a)(1), are clearly interchangeable. Gas is thus produced when it is severed. "Severed" is defined at §40-20-1(6) as "[t]he extraction or withdrawing from the soil or water or from below the surface of the soil or water of any oil or gas, ..." Gas is thus severed, i.e., produced, when it is brought above the soil or waters of Alabama, which as a practical matter is at the top of the well bore at or near the wellhead apparatus.

The above conclusion is supported by several other severance tax statutes. "Value" is defined at §40-20-1(3) as the "sale price or market value at the mouth of the well." The Department concedes that the point of production and the mouth of the well are synonymous. As indicated, however, it contends that the mouth of the well for severance tax valuation purposes is the first meter after the separator on the central platforms concerning the Mobile Bay wells, and the post-separation meter at the respective plants concerning the BEC and LEC wells. But as illustrated below, the evidence establishes, and common sense dictates, that the mouth of the well must be a part of the well structure, and specifically, a point at or near the wellhead apparatus at the top of the well bore where the gas leaves the well and enters the gathering system.

"Oil" is defined at §40-20-1(4) as hydrocarbons "produced at the well in liquid form by ordinary production methods and which are not the result of condensation of gas after it leaves the well." "Well" is not defined by the severance tax statutes. However, pursuant to §40-20-1(17), a well is completed for severance tax purposes when drilling has ceased, which indicates that a well is a hole drilled in the ground through which oil or gas rises to the surface. Further, a well is commonly understood to mean and is generally defined as "[a] deep hole or shaft sunk into the earth to obtain water, oil, gas, or brine." *American College Heritage Dictionary* 1556 (4th ed. 2002). Consequently, oil (and gas) is produced in the well structure, and production does not include activities after the product leaves the drilled well and enters the gathering system.

"Producer" is defined at §40-20-1(8) as "[a]ny person . . . producing in any manner any oil or gas by taking it from the soil or waters, or from beneath the soil or waters, of the State of Alabama. . . ." Gas is thus produced when it is taken or removed from the soil or waters of Alabama, i.e., when it is severed. This occurs in the well structure at or near the wellhead apparatus when the gas rises above the surface of the soil or water, not at some downstream meter.

Section 40-20-2(b) specifies that the severance tax “shall accrue at the time such oil or gas is severed from the soil or the waters, or from beneath the soil or the waters, and in its natural, unrefined and unmanufactured condition.” Tax accrues when the amount of and liability for the tax is fixed. *Black’s Law Dictionary* 20 (5th ed. 1979). The value of oil or gas is thus fixed when it is severed, which, as discussed, occurs in the well structure at or near the wellhead apparatus. Also, §40-20-2(b) requires that the gas must be “in its natural, unrefined and unmanufactured condition” at the point of valuation. Exxon’s Mobile Bay gas is altered from its natural condition when the various liquids are injected and the gas is cooled as soon as it enters the gathering system. Consequently, the point of production or valuation for the unrefined gas must be at the wellhead before the gas enters the gathering system.

The Alabama Supreme Court, in *Phillips Petroleum*, also repeatedly referred to the value of gas “at the wellhead.” See, *Phillips Petroleum*, 638 So.2d at 887 – 890. Likewise, the Administrative Law Division has in numerous cases referred to the severance tax as a tax on the value of oil or gas at the wellhead, and that the point of production is at the wellhead at the top of the well structure. See, *Clay Calhoun*, *supra*; *Petro-Lewis*, *supra*; *Torch Operating*, *supra*; *Smacko Operating, LLC v. State of Alabama*, Misc. 02-787 (Admin. Law Div. 5/23/03); *Esco Oil & Gas, Inc. v. State of Alabama*, Misc. 00-310 (Admin. Law Div. 5/8/01); and *State v. FMP Operating Co.*, Misc. 89-154 (Admin. Law Div. 5/4/95). In none of the above cases, or in any other severance tax cases decided by the Administrative Law Division, has the Department ever argued that the taxable point of production was anywhere other than at the wellhead apparatus at the top of the well.

The Department contends that Exxon's position as to "point of production" in this case is inconsistent with Exxon's position in its ongoing royalty dispute with the State that is currently pending before the Alabama Supreme Court. *Exxon Corp. v. Dep't of Conservation and Natural Res.*, Montgomery County Circuit Court Case No. CV 99-2368, Ala. S. Ct. Docket No. 1031167. The pending royalty dispute is irrelevant, however, because, as acknowledged by the Department's experts, royalty computations are governed by the contract between the parties, whereas severance tax computations are governed by the applicable statutes.[3] Consequently, what the parties argued in the royalty case is irrelevant for purposes of determining the point of production and what workback deductions must be allowed for severance tax purposes.

The Department's own workback regulation, Reg. 810-8-6-.01, also supports Exxon's position that the point of production is at or near the wellhead at the top of the well bore. Reg. 810-8-6-.01(2)(b) defines "production costs" as "[a]ll costs incurred for acquisition, exploration, development, maintenance, and abandonment of a well." Production costs thus do not include any downstream processing costs incurred after the unrefined product leaves the well structure and enters the gathering pipes.

Paragraph (2)(g) of the regulation defines "point of production" as "[t]he mouth of the well as defined in (2)(h)." Paragraph (2)(h) defines "mouth of the well" as "[t]he point of production where the well production is severed from the soil or the waters, or from beneath the soil or the waters" of Alabama. The regulation thus identifies the point of

---

[3] For the testimony of Department expert George Bower on this point, see (R. 1572, 1573); for the testimony of George Tiblier, see (R. 1958, 1959); and for the testimony of Saul Solomon, see (R. 2042).

production as the mouth of the well where the gas is physically extracted or severed from beneath the soil or waters of Alabama. To reiterate, this occurs at some point in the well bore at or immediately before the gas flows through the wellhead apparatus at the top of the well structure.

The Department does not explain why the "point of production" and "mouth of the well," as defined in its workback regulation, should not be followed. Rather, it ignores the regulation, and instead argues that it is universally recognized in the oil and gas industry that the point of production is the first meter after separation at which the product can be identified and measured. The Department submitted expert testimony and numerous statutes and regulations from other states in support of that claim.

I agree that other states may treat various activities downstream from the wellhead as production-related. In Idaho, for example, the production process for natural gas is completed "after extracting from the well, gathering, separating, injecting and any other activity which occurs before the outlet of the initial dehydrator." See, Idaho statute §32-14-203(b)(iv). Dept. Ex. 218-D(2). But how Idaho or any other state may statutorily define the production process or otherwise value oil or gas for severance tax purposes is irrelevant. Alabama law must control in this case, and as discussed, Alabama's severance tax statutes, and the Department's own regulation, when read together, establish that the point of production at which oil or gas must be valued is where the unrefined product is physically severed from the soil or waters of Alabama, which is at the top of the well structure at or near the wellhead apparatus. That conclusion was supported by the testimony of Exxon's expert witnesses at the June

2004 hearing.[4]

Dept. Reg. 810-8-6-.01(2)(a) further supports Exxon's position that production occurs in the well because it identifies the cost of gathering prior to separation as an allowed cost. A Department witness conceded that transporting the Mobile Bay gas from the templates to the central platforms is gathering. (R. 1046, 1047) Consequently, if the Mobile Bay gathering lines are a post-production processing cost, as specified in Reg. 810-8-6-.01(2)(a), production must occur in the well before the gas enters the gathering line.

Also, while the main gas stream is metered after it leaves the platform separator, some gas remains in the liquids that settle in the separator. That gas is separated from the liquids in the platform flash tank, compressed, and commingled with the gas in the main gas line at some point downstream from the post-separation meter. Additional gas is also removed from the liquids onshore and commingled with the main gas stream. Consequently, if the Department's position is accepted, some Mobile Bay gas sold by Exxon at the plant tailgate is never technically "produced" because it never passes through the post-separation meter, i.e., the "point of production," as defined by the Department.

Finally, if the point of production for the LEC gas is the meter at the St. Regis plant in Florida, as argued by the Department, then Alabama severance tax is not due on the gas because it is not produced in Alabama. A Department witness attempted to explain by testifying that "tax is attached to the product as soon as it leaves the ground in Alabama. It's just not considered produced for purposes of determining the workback

[4] For the testimony of Ken Hanby on this point, see (R. 625 – 627); for the testimony of Dr. Bob Enick, see (R. 429 – 431).

method until its gone through that separation process" at the St. Regis plant. (R. 1005) There is, however, no basis in Alabama law for that implausible explanation. Rather, the Department's position is contrary to Alabama's severance tax statutes and its own regulation, which establish that the point of production or valuation for severance tax purposes is at the top of the well structure at or near the wellhead apparatus where the gas is severed from the soil or waters of Alabama.[5]

Issue (2). The Workback Deductions - Generally.

The only guidance from Alabama's appellate courts concerning the workback deductions is the Supreme Court's broad statement in *Phillips Petroleum* that all "costs of transportation, processing and treatment" should be allowed. *Phillips Petroleum*, 638 So.2d at 888. That statement was only dicta, however, because the workback deductions were not in issue in *Phillips Petroleum*, only whether the Department could use the method as an alternative valuation method.

As a preliminary matter, it must be understood that some costs incurred by a producer/processor relate to both production and processing, and that the amounts attributable to production versus processing sometimes cannot be mechanically measured or otherwise precisely determined. Consequently, those deductions must necessarily be estimated. The deduction for indirect administrative overhead is an example.

---

[5] The Department concedes that if unrefined gas is actually purchased at the wellhead, it is considered produced at that point. (R. 1016) I agree. As discussed, the point of production is at or near the wellhead apparatus where the gas is physically severed from the soil or waters of Alabama. It makes no sense, however, to then argue that if the raw gas is not sold at the wellhead, the point of production somehow moves downstream to the first meter after separation. Gas is produced at the wellhead whether it is sold there or not.

Indirect overhead represents the secretarial, accounting, marketing, legal, and other administrative expenses not directly booked to a project, but which are necessarily incurred concerning the project. For example, some portion of Exxon's accounting, legal, and administrative staffs in Houston, Texas perform work relating to Exxon's Mobile Bay and Escambia County operations. The Department concedes that the Alabama-related portion of those indirect costs that involve processing or marketing should be allowed. Unfortunately, while Exxon's total administrative overhead can be determined, there is no accurate method for measuring or otherwise precisely identifying the percentage of total overhead that is attributable to Exxon's processing-related Alabama activities, and thus deductible for Alabama severance tax purposes.

The Department recognized before Reg. 810-8-6-.01 was promulgated in 1997 that the amount of deductible indirect overhead could not be precisely measured. It thus routinely estimated the percentage of such overhead that should be allowed. In *Torch Operating*, for example, the Department allowed 40 percent and 100 percent of total overhead in Torch audits involving pre-1997 periods. *Torch Operating*, at 11.

The Department attempted to resolve the problem by addressing the issue in Reg. 810-8-6-.01(6)(b)7. Unfortunately, that provision, which specifies that indirect overhead "shall be limited to" 10 percent of various direct costs, is poorly written and vague. The Administrative Law Division has interpreted the provision as allowing a fixed overhead deduction equal to 10 percent of the various direct costs listed in the regulation. The Department argues that the regulation caps or limits otherwise allowable overhead, which ignores the fact that allowable indirect overhead cannot be otherwise determined. Capping or limiting otherwise allowable overhead would also be contrary to the Supreme Court's holding in *Phillips* that all costs of processing the gas must be allowed.[6] But regardless of how the administrative overhead regulation should be interpreted, the point is that the deduction cannot be precisely recorded or determined, and must be estimated.

Employee field labor is another cost that is both production and processing-related. There is no reasonable recordkeeping method for precisely determining what portion of a field employee's time is spent on well-related versus processing-related activities. Consequently, as with indirect overhead, the allocation must necessarily be estimated. The Department recognized in *Torch Operating* that some field labor costs were deductible. It thus allowed approximately 15 percent based on an estimate devised by a Department examiner. The Administrative Law Division rejected that amount, and instead allowed approximately 68 percent based on the uncontroverted

[6] The indirect overhead issue was analyzed at length in *Torch Operating*, at 11 – 14, and *BP America*, at 30 – 34. On appeal, the Tuscaloosa County Circuit Court granted Torch's motion for summary judgment concerning the overhead issue, holding that "allowance for a 10% deduction for overhead costs as allowed by DOR regulation 810-8-6-.01(6)(b)7 is arbitrary and capricious. The overhead costs should be the actual processing related overhead costs incurred." *Torch Operating*, February 2, 2005 Order of Tuscaloosa County Circuit Court. The effect of the Court's finding is unclear, however, because Torch argued, and the Administrative Law Division affirmed, that because actual processing-related indirect overhead cannot be accurately determined, the 10 percent amount specified in the regulation should be allowed. I agree that the 10 percent amount in the regulation is arbitrary, and so stated in *BP America*. See, *BP America*, at 33, n. 15. However, absent evidence showing that the amount is unreasonable and does not reasonably reflect or estimate the amount of deductible indirect overhead, the regulation should be followed because, as discussed, actual processing-related overhead cannot be otherwise accurately determined. See generally, *Ex parte White*, 477 So.2d 422 (Ala. 1985) (Department regulation should be affirmed unless unreasonable or contrary to the statute to which it relates). (The above cited Tuscaloosa County Circuit Court Order was not entered until after the hearing in this case, and thus was not included in the record at the hearing. The Administrative Law Division has taken official notice of the Order, and for the benefit of any reviewing court, the Order will be included in the record on appeal.)

testimony of Torch's field supervisor, which was the best evidence available. *Torch Operating*, at 5 – 8.[7] The Department took a harder line in *BP America* and refused to allow any field labor because BP did not maintain records identifying deductible field labor. The Administrative Law Division, recognizing the uncontested fact that some field labor was processing-related, estimated the deductible amount to be approximately 39 percent of total field labor costs, again based on the uncontroverted and believable testimony of a field supervisor. *BP America*, at 21 – 24.

The above perhaps too detailed discussion of indirect overhead and field labor is included to alert the reader as to one of the inherent difficulties in the workback method, i.e., that some allowed deductions cannot be precisely measured and must be estimated. With that in mind, I now turn to the central issue – what post-production costs or expenses should be allowed as workback deductions?

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

[7] In its February 2, 2005 Order, the Tuscaloosa County Circuit Court denied Torch's motion for summary judgment concerning field labor, holding that only expert testimony on the issue of value can be allowed. I respectfully disagree. While the Supreme Court held in *Phillips Petroleum* that "value may be shown by expert testimony," *Phillips Petroleum*, 638 So.2d at 889, it did not preclude the reliance on other relevant, admissible evidence, nor can I think of any reason why it should. The Supreme Court also stated that "[v]alue is a question of fact," and that any determination of value by the Department "can be attacked by showing that the calculations improperly included or excluded items (costs) in such a manner that the end result does not fairly indicate value." *Phillips Petroleum*, 638 So.2d at 889, 890. Admissible testimony or documentary evidence relevant to the issue of value thus should be allowed. See generally, Code of Ala. 1975, §40-2A-9(j).

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:

> 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.

BP America, at 40.

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.[8] 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

[8] The Administrative Law Division held otherwise in *Clay Calhoun* when it found that the cost of disposing of water produced with the gas was an "indirect" cost, and thus not deductible. *Clay Calhoun, Sr. v. State of Alabama*, Misc. 89-115 (Admin. Law Div. O.P.O. 10/31/95), at 12. On further review, I now believe, as indicated above, that the holding in *Clay Calhoun* on that point is incorrect.

Bower, "[a]ll of those functions are required." (R. 1634)

The Department's official position, at least in prior cases and presumably in this case, is that only those direct costs incurred in physically treating and transporting the product should be allowed. I disagree because, as discussed, numerous costs not directly related to the physical processing and transporting of oil or gas are unquestionably allowed as workback deductions. Ad valorem taxes, insurance, and administrative overhead are not direct processing-related costs, but are allowed costs in the Department's workback regulation, see Reg. 810-8-6-.01(6)(b)6., 7., and 8., respectively. Depreciation and return on investment are two more "indirect" costs that are allowed at Reg. 810-8-6-.01(6)(b)1. and (b)2., respectively.[9]

To summarize, in computing the taxable value of Exxon's gas at the wellhead, all post-production costs incurred by Exxon in transporting, processing, and treating its gas downstream from the wellhead, and all other direct and indirect costs necessarily incurred or resulting from those activities, should be allowed.

---

[9] The Circuit Court in *Black Warrior Methane* held that "ROI is found to be an element of the workback method, according to case law." *Black Warrior Methane*, at 5. Unfortunately, the cases relied on were not cited. The Department accepted the Court's finding, and now allows an 11 percent ROI on the capital investment in processing-related equipment and facilities. See, Reg. 810-8-6-.01(6)(b)2.

I frankly do not fully understand why ROI should be allowed as a workback deduction. I realize that in deciding whether to construct a gathering and processing facility, a producer may consider the profit or ROI that it could realize if the money was otherwise invested. But by investing in an oil and gas facility, the producer is, at least theoretically, also realizing a return on investment. Consequently, it has not "cost" the producer the ROI it could have otherwise earned from the money. The producer has simply elected to receive an ROI on its processing facility in lieu of the ROI it could have theoretically earned by otherwise investing the money. Presumably, the producer invested in the processing facility with the hope that the ROI on the facility would be greater than the ROI it could have realized from otherwise investing the money. In any case, the Department does not dispute that an ROI deduction should be allowed.

The Mobile Bay Deductions.

(A) The well templates and related equipment.

The offshore templates in Mobile Bay are production-related to the extent they allow Exxon's employees to monitor and maintain the wells, wellheads, and Christmas trees. They are primarily processing-related, however, because they support the gathering lines, the equipment used to inject the various liquids into the gathering lines, and the template coolers. Consequently, most of the template costs must be allowed. But like administrative overhead and field labor discussed above, the exact amount of the template costs that should be allowed can only be estimated.

Testimony indicated that the templates would only be one-quarter of their size if the large processing-related coolers were not required. The injection-related equipment also requires the templates to be larger. A reasonable allowance for the cost of the template structures is 75 percent of their cost.

The coolers and the injection equipment on the templates are clearly processing-related. The coolers are required to cool the gas so that it can be safely transported downstream in the gathering lines. The injected liquids and related equipment, including the lines needed to deliver the liquids from onshore to the templates, are required to prevent the gathering pipes and downstream equipment from plugging. The costs of the above items should be allowed in full.

(B) The gathering lines.

Post-production gathering costs incurred prior to separation are correctly included as an allowed processing cost in Reg. 810-8-6-.01(2)(a). Various Department witnesses testified that transporting the gas from the wells in Mobile Bay to the central platforms was gathering. See, Exxon Ex. 602, at 143 – 145, and (R. 1046, 1047 and 1600, 1601). The Department allowed various percentages of the Mobile Bay gathering costs in its preliminary audit reports, but now argues that none can be allowed. In its June 15, 2004 "Issues" letter submitted in response to the Administrative Law Division's Fifth Preliminary Order, the Department stated as follows, at 5:

> Gathering is the simple transportation of gas from a series of wells to a central point under normal flowing conditions. Gathering is not an exotic metallurgy extremely expensive high pressure flowline from a single well to a production platform that is designed to handle the very hot full well stream plus dilution water and plus dilution diesel along with the capability of cooling the gas and shutting in the well against full wellhead pressure of some 12,000 psi at the central production platform. What Exxon calls gathering is an extension of the wellhead that is properly called a flowline and, as such, is a production expense.

I disagree. To begin, there is no difference between a gathering line and a flowline. Both terms refer to the post-production pipes used to transport the gas to the central platforms.

Also, Exxon did not use expensive nickel-based alloy to construct the remote well gathering lines in Mobile Bay so that it could get a larger workback deduction. Rather, it used the expensive materials for valid environmental and safety reasons. The expensive, high-pressure pipes are less likely to leak, and can be shut off with minimum damage if leaks or other problems arise. Exxon must be allowed what it spent to transport the gas in Mobile Bay, not the minimum amount it could have spent on less safe pipe. In any case, the Department's position, per its June 2004 audit report, is that none of the gathering pipe should be allowed, even the common steel pipe used to gather the gas from the close-proximity wells. That position is incorrect because it is premised on the Department's erroneous position that gathering is production-related, which is contrary to its own regulation. The Mobile Bay gathering system must be allowed.

(C) The central platforms.

The manifolds and headers, pipes, coolers, separators, contactors, dehydration units, and the other equipment on the platforms function to transport, process, or treat the gas, and are clearly "allowed costs" as defined at Reg. 810-8-6-.01(2)(a). The cost of the platform structures that support the processing equipment must also be allowed. Provided, some utilities on the platforms relate to the wells, and the platform employees spend some time on well-related activities. Consequently, a small portion of the platforms and platform-related costs are production-related, and not deductible. Exxon should present evidence at the stage two hearing from which an accurate allocation can be made.

(D) The post-platform pipes.

The pipelines between the central platforms, and also the central line that takes the gas to the onshore facility, are clearly allowable as a cost of transporting the gas. Likewise, the separate line through which the spent diesel and other liquids are transported onshore must be allowed. The liquids are separated during processing, and Exxon is required to transport the liquids onshore for further treatment. It is a cost necessarily incurred in processing the gas.

(E) The onshore facility.

(1) Sulfur costs

Exxon removes the hydrogen sulfide from the Mobile Bay gas by passing it through an amine contactor at the onshore facility. The hydrogen sulfide must be disposed of, but cannot be safely vented or burned. Consequently, Exxon converts it into liquid sulfur and then sells it.

Removing the hydrogen sulfide is a required step in the processing of the gas. Converting the sulfide into liquid sulfur is also an allowed cost because it is required before Exxon can dispose of the sulfide.

The cost of removing and disposing of the hydrogen sulfide must be offset by the revenue from the sale of the liquefied sulfur, but any excess sulfur costs must be allowed. This is consistent with Reg. 810-8-6-.01(6)(b)10.(ii), which specifies that the cost of recovering sulfur over the revenue derived from the sale of the recovered sulfur shall be allowed. The regulation was not effective until April 1997. However, subparagraph (6)(b)10.(ii) is a correct application of the workback method, and should be applied concerning the Mobile Bay facility to the pre-April 1997 period in issue.

An ROI should also be allowed concerning Exxon's capital investment in the sulfur-related equipment and facilities. Reg. 810-8-6-.01(6)(b)2. specifies, and the Department concedes, that a ROI is allowed on processing-related equipment. The removal of the hydrogen sulfide is processing-related, and the subsequent conversion of the sulfide into sulfur is a necessary step in disposing of the sulfide. Consequently, a ROI must be allowed on the sulfur-related capital equipment.[10]

(2) Water disposal.

The Department apparently concedes that the cost of disposing of the water used in processing the gas at the onshore plant should be allowed. See,

---

[10] Department Reg. 810-8-6-.01(6)(a)4. is rejected in that it incorrectly provides that a facility used to convert hydrogen sulfide into sulfur should not be included in the investment basis.

Department's Post-Trial Brief at 12. I agree. The removal and disposal of the water is required and necessarily results from the processing of the gas. Likewise, the cost of disposing of the water produced with the gas should also be allowed because the produced water must be separated from the gas, and once separated, it must be disposed of. See, *supra*, at 21, n. 7. A prospective buyer would consider the cost of disposing of the produced water in deciding what to pay for the gas at the wellhead. The cost affects wellhead value, and must be allowed.

(3) Electricity.

Exxon's onshore facility is a processing facility. The extensive electrical distribution system at the onshore facility is thus a processing-related cost, and must be allowed.

Exxon operates the steam generator and two of the three gas generators at the onshore facility at maximum capacity for efficiency purposes. It sells the excess electricity to Alabama Power Company. The third gas generator was installed in case one of the other gas generators fails or is down for maintenance or repairs. However, Exxon operates all three gas generators during the Summer months and then sells the excess electricity to Alabama Power.

The Department argues "that the portion of the operating generating capacity that is actually used to run the gas treating and dehydration equipment (at the onshore facility) is an allowable deduction." Department's Post-Trial Brief at 8. Exxon counters that the cost of the electricity used for a deductible function at the onshore facility should be allowed, net of any revenue derived from the excess electricity sold to Alabama Power.

Exxon installed the one steam and three gas generators to operate the onshore processing facility, not to produce and sell excess electricity. The generators are thus an allowed cost under the workback method. The revenue from the excess electricity sold to Alabama Power should be applied to offset Exxon's cost of producing the electricity. Assuming that Exxon sells the excess electricity to Alabama Power for more than what it cost to produce the excess electricity, which is a reasonable assumption, that profit will go to reduce the electricity costs incurred in operating the facility. In net effect, Exxon will be allowed less than what it actually cost to produce the electricity needed to operate the plant.

(F) Other Mobile Bay deductions.

(1) Diamondoids

Some diamondoids remained in the stripped diesel sold by Exxon during the periods in issue. The Department concedes that Exxon's diamondoid-related costs can be deducted to offset the receipts from the sale of the stripped diesel, but that any excess diamondoid costs are production-related, and cannot be allowed. Department's Post-Trial Brief at 7, 8. I disagree.

Injecting the diesel to dissolve the diamondoids and then removing the diesel and dissolved diamondoids from the gas stream are required processing-related functions, and must be allowed in full. There is no valid rationale for limiting the diamondoid-related costs to the amount of revenue derived from the sale of the stripped diesel. The excess diamondoid treatment costs must be allowed in full, the same as excess sulfur costs must be allowed per Reg. 810-8-6-.01(6)(b)10.(ii).

The Department stated in its June 15, 2004 "Issues" letter, at 7, that sulfur costs are allowed "on the assumption that (the producer) would not be in the sulfur business if (the producer) was not in the gas business, . . ." Likewise, Exxon would not be in the stripped diesel "business" if it was not in the gas business. The sulfur and stripped diesel are both incidental by-products resulting from the processing of the Mobile Bay gas. The revenue from the sale of those by-products should go to reduce the related processing costs incurred by Exxon, but any excess processing costs must be allowed in full.

(2) Fuel Gas

Fuel gas is gas produced and processed by Exxon that Exxon uses to operate the gas-powered equipment at the Mobile Bay facilities. Dept. Reg. 810-8-6-.01(6)(b)5.(iii) allows a "fuel cost deduction of $.68 per MCF or actual cost . . . , up to said gross value, for the cost of producing the fuel."

The $.68 per mcf allowed by the regulation is based on the Circuit Court's finding in *Black Warrior Methane* that the cost of producing the coal bed methane in issue in that case was $.68 per mcf. However, that figure does not necessarily reflect what it may cost Exxon to produce fuel gas in the offshore wells in Mobile Bay. There is also no rationale for capping the fuel gas deduction at the value of the gas at the wellhead. Rather, the actual cost of producing fuel gas must be allowed in full.[11] A return on investment concerning the fuel gas should also be allowed. The Administrative Law Division addressed the fuel gas issue in *BP America*, as follows:

[11] The cost of processing the gas into usable fuel gas is otherwise allowed in general processing costs. See, *BP America*, at 36, n. 17.

> The Department allowed Amoco the $.68 per mcf specified in subparagraph (iii) of the regulation. That was the amount the Tuscaloosa County Circuit Court found to be the actual cost of producing the gas in *Black Warrior Methane*. There is no evidence, however, that it cost Amoco $.68 per mcf to produce the fuel gas in issue. The workback method requires, and the Department concedes, that Amoco "is entitled to its actual costs of producing (the fuel gas)." Department's Brief at 75. That actual cost should be allowed.
>
> Subparagraph (iii) of Reg. 810-8-6-.01(6)(b)5. also limits or caps the actual cost of producing the gas to the gross value of the gas at the wellhead. But as with Amoco's overhead deduction (and the administrative expenses in *Black Warrior Methane*), the actual cost of producing the fuel gas must be allowed in full and cannot be limited by Department regulation.
>
> Finally, the Department argues that the cost of producing the fuel gas should not include a return on investment because return on investment "is a profit allowance, not an actual out-of-pocket cost." Department's Brief at 75. I disagree for the reasons explained in detail in *Torch Operating*, Opinion and Preliminary Order at 14 – 18. Return on investment is an allowed cost under the workback method and must be allowed the same as depreciation, which the Department concedes is an allowed cost in determining the cost of producing fuel gas. See again, *Torch Operating*, Opinion and Preliminary Order at 16.

BP America, at 37, 38.

(3) Capitalized interest.

The Internal Revenue Code requires that certain interest paid or incurred by a taxpayer must be capitalized. See, 26 U.S.C. §263A. The parties apparently agree that Exxon should be allowed capitalized interest concerning the Mobile Bay operations. See, Exxon's Post-Hearing Brief at 72 – 75, and Department's Post-Trial Brief at 12. Capitalized interest should thus be allowed concerning Exxon's processing-related activities in Mobile Bay as identified herein.

(4) Royalty allocation.

The State of Alabama owns a royalty interest in the gas produced in

Mobile Bay. A royalty interest owner is considered a "producer" under Alabama law. Section 40-20-2(b). However, because the State is exempt from Alabama severance tax, the tax due on the Mobile Bay gas must be allocated between Exxon and the State. This is not a workback issue, but the issue must be decided before Exxon's liability for the subject periods can be fully decided.

Exxon argues that the royalties it paid the State should be subtracted 100 percent from the wellhead value of the gas. Exxon claims that the Department would allow less, although the Department's position as to what it would allow is not stated in its Brief. See, Department's Post-Trial Brief at 8, 9. The Department apparently contends that the royalty percentages stated in the various lease agreements should control because they represent the State's percentage share of the gas produced at the wellhead. See, Exxon's Post-Hearing Brief at 80.

I have not finally decided this issue. My first reaction was that the percentages stated in the royalty agreements reflected the State's percentage ownership of the gas at the wellhead, and that those percentages should control. It is unclear, however, what the percentages in the royalty agreements represent. Exxon has also cited authority contrary to that position. The parties should further develop the facts, and the Department should state its position concerning this issue at the stage two hearing.

The BEC and LEC Deductions.

Exxon should be allowed to deduct the same costs, i.e., gathering lines, sulfur treatment, wastewater disposal, etc., incurred at the BEC and LEC fields and facilities that are allowed in Mobile Bay. Provided, Exxon agrees that its pre-April 1997 sulfur costs incurred at the BEC and LEC fields should not be allowed based on the 1989 "Houston Agreement" entered into by the Department and various oil companies, including Exxon. See, Exxon's Post-Hearing Brief at 57, n. 25. Several other issues unique to the onshore fields are addressed below.

(A) Take-in-kind volumes at BEC.

This issue is not a workback issue. Rather, like the royalty allocation, it relates to who is responsible for paying the tax to the Department.

Numerous interest owners in the BEC field elected to take their product in-kind in lieu of being paid for the production. The owners then sold or otherwise disposed of the product as they saw fit.

Exxon claims it is not liable for the severance tax due on the product taken in-kind by the owners at BEC. It argues that even if it is liable, it does not have access to the tax returns of the in-kind owners, and thus cannot prove whether the owners paid the tax due in full. Exxon contends that at the least, the Department should be required to prove the amount of the gas taken in-kind, and also that the in-kind owners failed to report and pay tax on those volumes.

The Department acknowledges that "[i]n Exxon's case only, certain in-kind producers have been allowed to pay their own taxes when Exxon identified them to the Department and reported the amounts taken in kind." Department's Post-Trial Brief at 11. The Department claims, however, that because Exxon failed to identify the in-kind owners, Exxon remains liable for the tax due.

This issue has never been addressed by Alabama's courts or the Administrative Law Division. Technically, the interest owner is the producer of the oil or gas, and the tax is levied on such owner; provided, the tax shall be paid by the person in charge of production operations, who must deduct or withhold the tax due "before making payments" to the producer/owner. Code of Ala. 1975, §40-20-3(a). If the person in charge of production fails to pay, the Department may then go against the producer/owner or the party that purchased the product. See again, §40-20-3(a); see also §40-20-3-(b).

Section 40-20-3(c) further provides that if the person in charge of production disposes of the oil or gas "for fuel or any other purpose," the person shall withhold the severance tax due.

Finally, §40-23-3(d) reiterates that if the person in charge of production fails to deduct or withhold the severance tax due, "when such oil or gas is sold or purchased under contract or agreement, or in the open market, or otherwise," that person shall be liable for the tax due.

Exxon argues that §40-23-3 requires the person in charge of production to withhold and pay the tax due only if the person sells the product in question. Exxon thus asserts that it is not liable for the tax on the gas taken in-kind at BEC because it did not sell the in-kind gas.

Subsections (b) and (d) of §40-23-3 do presuppose that the person in charge of production will sell the oil or gas. However, §40-20-3(a) specifies that "the tax shall be paid by the person in charge of production operations, . . ." That responsibility is not contingent on whether the person in charge of production subsequently sells the oil or gas. Section 40-20-3(c) also makes the person in charge of production liable if the oil or gas is disposed of "for . . . any other purpose." Consequently, Exxon, as the entity in charge of production operations at the BEC wells, is ultimately liable for the tax due on the take-in-kind product distributed to the owners.

The above applies, however, only if Exxon was in charge of production at a well. Exxon would not be liable if a well owner, and not Exxon, was in charge of production. In that case, the interest owner would be the person in charge of production and also the producer, and thus liable for the severance tax due. Exxon stated in its Post-Hearing Brief at 89, n. 4, that it did not operate all of the BEC wells. I assume that if Exxon did not operate some wells, it was not the person in charge of production at those wells, and thus not liable under §40-20-3(a). Exxon should be prepared to identify the BEC wells operated by the owners at the stage two hearing.

Exxon and all other oil and gas producers are required to keep complete records showing the volume of gas severed, etc. Code of Ala. 1975, §40-20-5(b). I assume that Exxon maintained a record of the interest owners in the BEC field, and also the owners that operated their own wells. I also assume that the volume from each well operated by Exxon was metered and recorded. Consequently, it is unclear why Exxon did not (or could not) provide the Department with a list of the BEC interest owners that took their product in-kind, and the volume taken. My understanding is that if Exxon identified the in-kind owners and the amounts they received, the Department agreed that Exxon would be relieved of liability. It would then be incumbent on the Department to verify that the in-kind owners actually paid the tax. Exxon should explain at the stage two hearing why it is unable to provide the above information to the Department (or the Administrative Law Division).

(B) The nitrogen rejection unit at LEC.

Exxon injects nitrogen into the LEC field to enhance production. The nitrogen must be removed before the produced gas can be sold. Exxon does so by running the gas through a nitrogen rejection unit ("NRU") at the St. Regis facility. The cost of removing the nitrogen is processing-related, and must be allowed.

The fact that Exxon injected the nitrogen to enhance production does not make the subsequent removal of the nitrogen a production-related activity. As discussed, production ends when the gas leaves the well and enters the gathering system. The Department, apparently recognizing that nitrogen removal is processing-related, allowed 50 percent of those costs in its preliminary audit reports. It now contends that none of the NRU costs should be allowed. But clearly the post-production removal of the nitrogen from the produced gas is 100 percent processing-related, and must be allowed in full.

Other Issues Raised in the Department's Post-Trial Brief.

As indicated, the parties agreed that the June 2004 hearing was for the sole purpose of identifying what workback deductions should be allowed. This Order addresses those issues. The Department nonetheless made various arguments in its Post-Trial Brief that are not relevant to the above issues. Those arguments are briefly addressed below.

The Department first asserts, at pages 1 and 2 of its Brief, that Exxon's arguments must be rejected because Exxon took a different position in its royalty dispute with the State. That claim has been adequately discussed, *supra*, at 13, 14. The positions taken by the parties in the royalty case are neither binding in this case, nor are they relevant to the issue of what costs or expenses incurred by Exxon should be allowed as workback deductions for severance tax purposes.

The Department also contends that the workback method must result in "a reasonable and rational value in the light of all the facts." Department's Post-Trial Brief at 3. But who is to decide if wellhead value as determined under the workback method is "reasonable and rational"? The Department cannot predetermine or assume what it considers to be a reasonable wellhead value for gas, and then arbitrarily reject the workback method results if it is less than the predetermined amount. Rather, if the workback method is correctly applied, the resulting wellhead value must be accepted.

Exxon's refund petitions were prepared by J.C. Thakker, a consultant employed by Shiv Om. Thakker's workback calculations indicated that Exxon's Mobile Bay gas had a zero value for many of the months in issue. Based thereon, the Department contends that Exxon, through Thakker, "tortured the 'workback deductions' concept into yielding results which wholly fail to comport with a rational resulting 'value.'" Department's Post-Trial Brief at 3.

First, this Order should not be viewed as accepting or agreeing with the calculations in Exxon's refund petitions. But even the Department concedes that under certain circumstances, the workback method may result in a zero or negative wellhead value. (R. 529) Also, the fact that Exxon's refund calculations showed zero value for many of the months in issue does not establish that Exxon must be "losing money every month," as claimed by the Department. See, Department's Post-Trial Brief at 5. If a producer sells refined gas at the plant tailgate for more than the operating costs incurred in processing and transporting the gas from the wellhead to the point of sale, the producer has realized an operating profit on the gas. But for workback purposes, the producer, in addition to deducting the operating costs incurred in actually processing the gas, is also allowed additional workback deductions for depreciation (5 percent of adjusted basis), ROI (11 percent of adjusted basis), administrative overhead, and other fixed indirect costs. Consequently, the producer may make an operating profit on the sale of gas but show a zero or negative value for workback purposes.

The Department next attacks Thakker's credibility, and also various of the deductions included by Thakker in Exxon's refund petitions. Department's Post-Trial Brief at 3 – 5. Thakker's credibility is, however, irrelevant to the issues addressed by this Order. In *BP America*, the Department attacked another Shiv Om employee, Ketan Thakker, who had prepared the refund petition in that case. As in this case, the Department argued that the Shiv Om calculations were tainted because Shiv Om had a contingency fee arrangement with BP. It also asserted that Thakker had falsely testified in the case. The Administrative Law Division rejected the Department's claims, as follows:

> The Department has spent much time and energy attacking the Shiv Om refund calculations, and also Ketan Thakker, personally. The Department's attacks on Thakker and his work product are laced throughout the transcript of the hearing and its 78 page brief. The Department claims, for example, that the Shiv Om petition is tainted because Shiv Om had a contingency fee contract with Amoco, and also that Ketan Thakker "willfully testified falsely as to material facts." Department's Brief at 25. However, contingency fee contracts are not per se improper, and I find no evidence to support the latter claim. In any case, the case does not turn on the accuracy of the Shiv Om calculations or the veracity of Thakker. Rather, as indicated, the issue is whether the Department correctly computed Amoco's liability pursuant to its workback method audit. Consequently, the Department's arguments concerning the specifics of the Shiv Om petition and its personal attacks on Thakker are irrelevant and will not be addressed further in this Order.

BP America, at 4, n. 1.

Likewise, J.C. Thakker's credibility and the accuracy of Exxon's refund petitions are irrelevant to the issues addressed by this Order – what costs or expenses should be allowed as workback deductions.

The Department also asserts that Exxon is bound by the provisions in Reg. 810-8-6-.01 because an Exxon employee, and other industry representatives, had input when the regulation was being drafted. Department's Post-Trial Brief at 4. Industry representatives may have made suggestions concerning the regulation, but the Department had the final say-so concerning the regulation. In any case, it is the Department, not Exxon, that is ignoring certain provisions in the regulation. As discussed, the "point of production" and the "mouth of the well," as defined in paragraphs (2)(g) and (2)(h) of the regulation, respectively, clearly establish that the point of production at which the gas must be valued is in the well bore at or near the wellhead apparatus, as argued by Exxon, not at some downstream meter, as asserted by the Department. Likewise, the Department claims that the gathering pipes in Mobile Bay and at the BEC and LEC fields cannot be allowed, although Reg. 810-8-6-.01(2)(a) clearly specifies that gathering prior to separation is an allowed cost. The Department has simply ignored the above regulatory provisions.

Finally, the Department touches briefly on the fact that Exxon contracted to process gas belonging to other producers (Hunt and Mobil/Shell) in Mobile Bay at considerably less per mcf than what it cost Exxon to process its own gas per Thakker's refund calculations. Department's Post-Trial Brief at 5. But what Exxon may have charged to process the gas belonging to Hunt and Mobil/Shell is not relevant in determining what workback deductions Exxon should be allowed.

Also, the Hunt and Mobil/Shell gas processed by Exxon was “incremental” gas. That is, Exxon had already spent the money to build the templates, platforms, pipelines, processing equipment, etc. for the purpose of processing its own gas in Mobile Bay. Those costs were thus fixed, and allowable under the workback method in determining what it cost Exxon per mcf to process its own gas. But in deciding what to charge for processing the Hunt and Mobil/Shell gas, Exxon only had to consider the incremental operating costs it would incur in processing the gas. Anything above that would be a profit. It thus follows that Exxon could charge less per mcf to process someone else’s gas than what it cost Exxon per mcf to build the processing facilities and infrastructure, and then actually gather and process its own gas in Mobile Bay.

CONCLUSION

Alabama’s severance tax statutes and Department Reg. 810-8-6-.01 establish that the point of production at which unrefined oil and gas must be valued is at the top of the well bore at or near the wellhead. The workback method for determining that wellhead value requires that all direct and indirect costs necessarily incurred between the wellhead and the point of sale of the refined product must be allowed because those costs affect the wellhead value of the product. The Department’s own expert confirmed that in determining the market value of gas at the wellhead, a prospective buyer would be required to consider all costs that would necessarily be incurred in bringing the gas to market.

This Stage One Order identifies the point of valuation and also the expenses or costs incurred by Exxon that must be allowed under the workback method. A stage two hearing will be conducted in due course at which the dollar amounts of the various deductions can be determined. Hopefully, the parties can agree prior to the stage two hearing concerning many of the dollar amounts that should be allowed pursuant to this Stage One Order. Any amounts agreed to will not, of course, prohibit or bar the Department from subsequently challenging the deductibility of the cost or expense on appeal.

The parties should notify the Administrative Law Division by February 28, 2006 as to whether a stage two hearing in June 2006 is feasible. They should also estimate the expected length of the hearing.

This Stage One Opinion and Preliminary Order is not an appealable Order. The Final Order, when entered, may be appealed to circuit court within 30 days pursuant to Code of Ala. 1975, §40-2A-9(g).

Entered February 8, 2006.

____

BILL THOMPSON
Chief Administrative Law Judge

bt:dr
cc: Henry C. Chappell, Esq.
John J. Breckenridge, Esq.
Conrad P. Armbrecht, Esq.
Duane A. Graham, Esq.
Janet Stathopoulos
Joe Cowen