INTRODUCTION

This federal income tax refund case is pending before the court following a trial on the merits held in Washington, D.C., from January 26 through February 13, 1998. Plaintiff, Exxon Corporation and its consolidated subsidiaries (hereinafter "Exxon"), seeks to recover the sum of $172,584,915.83, consisting of Exxon's alleged overpayment of federal corporate income taxes in the amount of $57,704,527.00 respecting its taxable year ended December 31, 1975, and assessed interest in the amount of $114,880,388.83, plus additional interest thereon as provided by law. The controversy at bar pertains to the amount of Exxon's claimed entitlement to percentage depletion deductions, pursuant to Internal Revenue Code §§ 611, 613, and 613A,[(1)] relative to certain sales of natural gas that Exxon produced along the Texas Gulf Coast and in the East Texas region during the taxable year 1975. By this opinion, we decide two primary questions. First, the court must determine what "representative market or field price" (RMFP), if any, within the meaning of Treas. Reg. § 1.613-3(a), must be used to calculate the allowance for percentage depletion with respect to Exxon's 1975 gas production in issue. Second, the court must decide whether the natural gas sold by Exxon during 1975, pursuant to its contracts with Houston Lighting & Power Company (HL&P) and Southwestern Electric and Power Company (SWEPCO), was "natural gas sold under a fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A).

Having thoroughly examined the trial record, we hold, *inter alia*, that for purposes of calculating Exxon's 1975 allowance for percentage depletion, the RMFP is $0.6831 per each thousand cubic feet (Mcf) of natural gas in issue that is eligible for percentage depletion. As to the second issue presented, we hold that Exxon has failed to prove, by clear and convincing evidence, the quantum of proof required by § 613A(b)(2)(A), that its contract with HL&P qualified as a "fixed contract," but has proven that the SWEPCO contract did so qualify.

BACKGROUND

I. *Exxon's 1975 Sales Of Natural Gas Pursuant To Long-Term Contracts*

During its taxable year 1975, Exxon produced raw natural gas from 369 properties situated along the Texas Gulf Coast and within East Texas.[(2)] Then, as now, Exxon was a fully integrated oil and gas company engaged in the exploration and production of crude oil and natural gas, and in the refining, transportation, purchase and sale of oil, gas, and products made therefrom. At issue are Exxon's 1975 sales of natural gas to 18 customers, made pursuant to long-term contracts entered into between 1955 and 1972.[(3)] Sixteen (16) of these contracts, entered into with industrial consumers of natural gas, were referred to by Exxon as its Texas Industrial Commitment (TIC), whereas the remaining two customers were pipeline companies engaged in the intrastate purchase, transportation and resale of natural gas. In 1975, Exxon delivered gas from the 369 properties in issue to the aforesaid 18 customers by means of its own gas pipeline transmission system, the Exxon Gas System (EGS). Exxon began construction of EGS in the 1930s, in order to connect its large natural gas reserves in the Texas Gulf Coast/East Texas region to the industrialized markets located along the northeastern section of the Texas Gulf Coast, in the general vicinity of, and between, the cities of Houston, Beaumont, and Port Arthur, Texas. By 1975, EGS extended 1,500 miles throughout the Texas Gulf Coast/East Texas region, and consisted of two primary, interconnected transmission pipelines -- one running from a point near Corpus Christi, a coastal city in South Texas, northward to a point near the city of Tyler in Northeast Texas, and the other running eastward from Houston to Port Arthur, near the Louisiana border. Generally, the flow of gas within EGS converged upon the Houston-Port Arthur industrial corridor, meaning that Exxon gas produced in the vicinity of Corpus Christi flowed northward, whereas gas from East Texas flowed southward. Most of the foregoing has, of course, been explicated in connection with the prior litigation over Exxon's percentage depletion deduction for its taxable year 1974. See Exxon Corp. v. United States, 33 Fed. Cl. 250, 262 (1995),[4] rev'd on unrelated grounds, 88 F.3d 968 (Fed. Cir. 1996), cert. denied, 117 S. Ct. 1252 (1997) (hereinafter, "Exxon I").

The vast majority of the gas sold by Exxon during 1975, pursuant to the 18 long-term contracts in issue, entered EGS *after* such gas was processed in one of Exxon's eight gas processing plants. Natural gas is composed principally of hydrocarbons, chemical compounds that contain carbon atoms and hydrogen atoms. Methane is the simplest, lightest hydrocarbon, consisting of a molecule with one carbon atom and four hydrogen atoms, and, in terms of volume, is typically the largest constituent of raw natural gas. Natural gas processing plants extract certain liquefiable hydrocarbons, or so-called "natural gas liquids," from the raw gas wellstream. Such natural gas liquids include ethane, propane, butanes, and heavier hydrocarbons (pentanes, hexane, heptane, octane, nonnane and decane) commonly referred to as "natural gasoline."[5] After the natural gas liquids have been extracted, the remaining natural gas consists primarily of methane, in proportions exceeding 90%, and is referred to as "residue gas." It is this residue gas that is transported by pipeline and burned as fuel by industrial users or consumers, *i.e.*, in a gas stove or furnace in the home. See also Exxon I, 33 Fed. Cl. at 256-58 (similar findings, relative to 1974, as to all of the foregoing).

About two-thirds of the gas at issue came from Exxon's King Ranch gas plant, located southwest of Corpus Christi in Kleberg County, Texas. Roughly another 17% of the gas at issue was processed in Exxon's Katy gas plant, located a few miles west of Houston in Waller County. Exxon's other four gas plants in the Texas Gulf Coast area, and the respective proportions of the gas in issue processed in each such plant, were: (i) the Anahuac plant, located east of Houston in Chambers County (approx. 4.5%); (ii) the Pledger plant, located southwest of Houston, and northeast of Corpus Christi, in Brazoria County (approx. 3.7%); (iii) the Clear Lake plant, located a few miles southeast of Houston in Harris County (approx. 2.4%); and (iv) the Lovell Lake plant, located east of Houston, and south of Beaumont, in Jefferson County (0.9%). Thus, in total, Exxon's six gas plants along the Texas Gulf Coast processed about 95.3% of the gas at issue. In addition, about 1.1% of the gas at issue was processed at Exxon's two gas plants in the East Texas area, located to the north of Houston in the general vicinity of the city of Longview: (i) the Hawkins plant in Wood County (1.0%); and (ii) the East Texas plant in Rusk County (0.1%). The remaining 3.6% of the gas at issue was not processed in an Exxon gas plant, and came primarily from the Trawick Field in East Texas, located to the north of Houston, but south of the Hawkins and East Texas gas plants, in Nacogdoches County.

Because Exxon transported all of the gas in issue away from the related 369 properties, and processed most of that gas as well, prior to sale, Exxon's percentage depletion deduction for the taxable year 1975 must be computed as if Exxon had sold its gas at a "representative market or field price" (RMFP), computed in accordance with Treas. Reg. § 1.613-3(a). The RMFP of natural gas "is calculated as the weighted average price of wellhead sales of comparable gas in the taxpayer's market area." Exxon I, 88 F.3d at 976. Thus, the discussion now turns to the statutory provisions, Treasury regulations, and case law that govern the computation of the allowance for percentage depletion and, specifically, the determination of the RMFP.

II. *The Statutory Allowance For Percentage Depletion -- Applicable Law*

A. *Introduction*

Depletion "reflects the exhaustion of a natural resource, such as natural gas, as a result of its severance from the earth." Exxon Corp. v. United States, 40 Fed. Cl. 73, 76 (1998) (opinion denying defendant's pre-trial motion for summary judgment) (citing Exxon I, 33 Fed. Cl. at 252). In 1975, the basic Code provision authorizing an income tax deduction for natural gas depletion stated, in relevant part:

In the case of mines, oil and gas wells, other natural deposits, and timber, there shall be allowed as a deduction in computing taxable income a reasonable allowance for depletion and for depreciation of improvements, according to the peculiar conditions in each case; such reasonable allowance in all cases to be made under regulations prescribed by the Secretary or his delegate.

I.R.C. § 611(a). Pursuant thereto, the Code specifies two methods by which the taxpayer may compute its depletion allowance -- cost depletion and percentage depletion. As to the substantive distinction between those two methods, the Supreme Court has observed:

Congress has allowed holders of economic interests in mineral deposits, including oil and gas wells, to deduct from their taxable incomes the larger of two depletion allowances: cost or percentage. Under cost depletion, taxpayers amortize the cost of their wells over their total productive lives. Under percentage depletion, taxpayers deduct a statutorily specified percentage of the "gross income" generated from the property, irrespective of actual costs incurred. . . . Taxpayers have historically preferred the allowance for percentage, as opposed to cost, depletion on wells that are good producers because the tax benefits are significantly greater.

Commissioner v. Engle, 464 U.S. 206, 208-09 (1984). Cost depletion, not in controversy here, produces a limited and predictable stream of annual tax deductions, over the productive life of a natural gas property, in that it merely recovers the taxpayer's actual capital investment, or cost basis, in the property. Exxon, 40 Fed. Cl. at 76 & n.6 (citing Engle, 464 U.S. at 209 n.2; Exxon I, 33 Fed. Cl. at 252). Percentage depletion, on the other hand, may yield deductions significantly exceeding the taxpayer's investment in the property, for it is based upon the *income* generated by the property throughout its productive life, rather than the cost of such property. Exxon, 40 Fed. Cl. at 76. Congress' intention, in structuring the statutory allowance for percentage depletion in the aforesaid manner, was to provide taxpayers an economic incentive to engage in the costly venture of oil and gas exploration and production, thereby increasing the nation's energy resources. Id. at 77 (citing authorities).

B. *Percentage Depletion Under Pre-1975 Law*

Our examination of the law governing Exxon's claimed entitlement to a percentage depletion deduction, with respect to the taxable year 1975, must necessarily begin with the statutory percentage depletion framework that was in place *prior* to 1975. As in effect for taxable years ending on or before December 31, 1974, the operative provision of the Code, relative to the allowance for percentage depletion, stated as follows, in pertinent part:

(a) General Rule. -- In the case of the mines, wells, and other natural deposits listed in subsection (b), the allowance for depletion under section 611 shall be the percentage, specified in subsection (b), of *the gross income from the property*

. . . .

(b) Percentage Depletion Rates. -- The mines, wells, and other natural deposits, and the percentages, referred to in subsection (a) are as follows:

(1) *22 percent* --

(A) *oil and gas wells*[.]

§§ 613(a), (b)(1)(A) (1974) (emphasis added). Thus, "prior to 1975, the annual allowance for percentage depletion equalled 22 percent of the taxpayer's gross income from sales of natural gas extracted from the property, subject to certain limitations not pertinent here." Exxon, 40 Fed. Cl. at 76.[(6)] The Code does not, however, prescribe a definition of the pivotal term, "the gross income from the property." Instead, Congress directed that the determination of a taxpayer's entitlement to a depletion deduction, including the allowance for percentage depletion, is "*in all cases* to be made under regulations prescribed by the Secretary." § 611(a) (emphasis added).

Pursuant to the foregoing delegation of rulemaking authority, the Secretary promulgated a Treasury Regulation that provides, in relevant part:

In the case of oil and gas wells, "gross income from the property," as used in section 613(c)(1), means the amount for which the taxpayer sells the oil or gas in the immediate vicinity of the well. If the oil or gas is not sold on the premises but is manufactured or converted to a refined product prior to sale, or is transported from the premises prior to sale, the gross income from the property shall be assumed to be equivalent to the *representative market or field price* [RMFP] of the oil or gas before conversion or transportation.

Treas. Reg. § 1.613-3(a) (emphasis added). This Regulation, including its substantially identical predecessors, has been continuously in effect since 1922. Exxon, 40 Fed. Cl. at 89 n.25 (citing authorities as to historical origins of RMFP method). Moreover, its validity is unquestioned, as demonstrated by numerous decisions in which the courts have repeatedly sustained Treas. Reg. § 1.613-3(a) as a permissible exercise of the Secretary's delegated authority to promulgate rules governing every aspect of depletion determinations. See, e.g., Exxon I, 88 F.3d at 974-76, 980, 33 Fed. Cl. at 265-69; Panhandle Eastern Pipe Line Co. v. United States, 187 Ct. Cl. 129, 408 F.2d 690 (1969); Hugoton Production Co. v. United States, 172 Ct. Cl. 444, 349 F.2d 418 (1965) ("Hugoton II"); Hugoton Production Co. v. United States, 161 Ct. Cl. 274, 315 F.2d 868 (1963) ("Hugoton I"); Exxon Corp. v. Commissioner, 102 T.C. 721 (1994) (percentage depletion issue similar to that presented here at bar, but relating to Exxon's 1979 taxable year); Shamrock Oil & Gas Corp. v. Commissioner, 35 T.C. 979 (1961), aff'd, 346 F.2d 377 (5th Cir.), cert. denied, 382 U.S. 892 (1965). See also United States v. Cannelton Sewer Pipe Co., 364 U.S. 76 (1960) (sustaining the RMFP method in the context of percentage depletion allowable to integrated producers of hard minerals).[(7)]

Conceptually, the fundamental purpose of Treas. Reg. § 1.613-3(a) is easy to grasp. Early percentage depletion cases uniformly recognized that an integrated producer's percentage depletion allowance must be computed upon the value of the natural gas "at the mouth of the well." Signal Gasoline Corp. v. Commissioner, 77 F.2d 728, 730 (9th Cir. 1935), cert. denied, 296 U.S. 657 (1936); Greensboro Gas Co. v. Commissioner, 79 F.2d 701, 701 (3d Cir.), cert. denied, 296 U.S. 639 (1935); Consumers Natural Gas Co. v. Commissioner, 78 F.2d 161, 163 (2d Cir.), cert. denied, 296 U.S. 634 (1935). This is so, as we have previously observed, "because integrated producers frequently transport and process gas after extraction and prior to sale, whereas nonintegrated producers commonly sell unprocessed gas near the wellhead." Exxon, 40 Fed. Cl. at 77 (citing Exxon I, 88 F.3d at 970; 33 Fed. Cl. at 252). From the viewpoint of a prospective buyer of gas, such transportation and processing add value to the gas, of course, because the integrated producer, not the buyer, bears the associated costs. Therefore, "integrated producers tend to sell natural gas at prices higher than those charged by nonintegrated producers and, concomitantly, integrated producers realize more gross income per unit of natural gas sold." Id. (citing Exxon I, 88 F.3d at 970; 33 Fed. Cl. at 252). See also Panhandle, 187 Ct. Cl. at 143, 408 F.2d at 700; Hugoton I, 161 Ct. Cl. at 277, 315 F.2d at 869 (to same effect). Given the aforementioned considerations, the purpose of Treas. Reg. § 1.613-3(a) is clearly to equalize the basis of entitlement:

Treas. Reg. § 1.613-3(a) is designed to maintain integrated and nonintegrated producers on an equal competitive footing, by requiring that the integrated producer's "gross income from the property" exclude post-extraction value added to the natural gas. . . . Thus, the RMFP calculation aims to ensure that an integrated producer is entitled to no greater percentage depletion deduction, for any given quantity of natural gas extracted, than its nonintegrated competitors.

Exxon, 40 Fed. Cl. at 77 (citing Exxon I, 88 F.3d at 975-76); Panhandle, 187 Ct. Cl. at 144, 408 F.2d at 700; Hugoton II, 172 Ct. Cl. at 455, 349 F.2d at 425; Hugoton I, 161 Ct. Cl. at 277, 315 F.2d at 869). In short, as the Federal Circuit has emphasized, "the fundamental goal of the [RMFP] calculation is to arrive at a price that is *representative* of the price which would be realized by nonintegrated producers." Exxon I, 88 F.3d at 976 (emphasis in original).

Regarding the mechanics of the RMFP determination, it is well settled that the RMFP of natural gas "is calculated as the weighted average price of wellhead sales of comparable gas in the taxpayer's market area." Exxon I, 88 F.3d at 976 (citing Panhandle, 408 F.2d at 703; Hugoton I, 315 F.2d at 877). So defined, the RMFP determination has three distinct elements: (i) the relevant market area; (ii) the comparability of the gas produced in such market area to the taxpayer's gas; and (iii) the qualification of sales of comparable gas in such market area as wellhead sales of unprocessed gas, *i.e*., sales of raw gas made "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). Each of these three elements (including certain sub-elements thereof) is the subject of detailed legal and factual analysis herein, *infra*.

Beyond the foregoing specifics, Exxon I and the other binding RMFP precedents above,[(8)] all decided under the pre-1975 law of percentage depletion, delineate two additional general principles. First, as a matter of law, it is of no consequence that the RMFP exceeds, even substantially, the taxpayer's *actual* gross income from its pertinent sales of natural gas. Exxon I, 88 F.3d at 976. The percentage depletion controversy in Exxon I centered upon Exxon's sales of gas, at prices well below the prevailing market price in 1974, pursuant to its 17 long-term TIC contracts then in force (16 of which are also at issue here at bar in relation to 1975). Id. at 970, 33 Fed. Cl. at 262. Despite the fact that the average delivery price of the gas sold under the TIC contracts was only $0.23 per thousand cubic feet (Mcf), inclusive of processing and transportation by Exxon, the Federal Circuit held that Exxon was entitled to base its 1974 percentage depletion deduction on a RMFP of $0.39/Mcf. Exxon I, 88 F.3d at 970, 979. Further, in reversing the decision below, 33 Fed. Cl. at 283-84, the Federal Circuit held that the trial court may not, pursuant to an independent reasonableness analysis, reject an otherwise valid RMFP. Id. at 980-81. On the contrary, instructed the Federal Circuit, once an RMFP is established in accordance with Treas. Reg. § 1.613-3(a) and the relevant precedents, it "is per se reasonable, absent a challenge to the regulation itself." Id. at 980.[(9)]

Second, the RMFP determination does not demand hypertechnical precision. Rather, pursuant to Treas. Reg. § 1.613-3(a), "the RMFP is employed as an inexact, simplified means of calculating an integrated producer's [percentage] depletion deduction." Exxon I, 88 F.3d at 976. The characteristic inexactitude of the RMFP computation stems from the fact that its objective is *not* the determination of an integrated producer's "actual gross income, a known figure," but rather, "a *constructive* gross income derived from the average wellhead market price for similar gas." Id. at 970 (emphasis added). Due to the RMFP method's "inherent uncertainties," Hugoton I, 161 Ct. Cl. at 282, 315 F.2d at 872, courts consistently acknowledge that the "calculation of the RMFP is a difficult and sometimes onerous task." Exxon I, 88 F.3d at 976.(10) However, "[i]f evidence of substantially comparable sales can be shown, . . . the price so derived *is not to be disregarded merely because it is an approximation*." Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 872 (emphasis added). Therefore, the precedents also instruct that the imprecision of the RMFP method can be ameliorated by using a sample of transactions that is "sufficiently large and diverse enough to discount variations and offset errors." Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 704. What is more, "larger sampling should provide greater assurance that the price derived is in fact *representative*." Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 (emphasis added), quoted with approval in Exxon I, 88 F.3d at 976. See also id. at 977-78 (emphasizing "the goal of maximizing the number of transactions included" in the RMFP sample). Taking our cue from the aforementioned authorities, we employ the term "RMFP sample" herein, generally, to describe any group of transactions that is under consideration for the RMFP computation.

A great deal more remains to be said about the RMFP, of course, regarding the particulars of the relevant market area determination, the gas comparability inquiry, and the operative definition of a wellhead sale, but each of those matters is best examined in light of the evidence pertinent thereto, and shall be addressed below in due course. Thus, having outlined the *pre*-1975 law of percentage depletion, as it applied to an integrated producer of natural gas, the discussion now turns to the legislative changes brought about by the Tax Reduction Act of 1975.

C. *Percentage Depletion Under Post-1974 Law*

By 1975, Congress grew convinced that the continuing need to provide a tax incentive for oil and gas exploration and production, *i.e*., percentage depletion, was outweighed by the public outcry over the nation's increasing dependence on foreign oil and gas, the Arab oil embargo, soaring energy prices, and the perceived windfall profits being reaped by the major integrated oil and gas companies, Exxon included. See Engle, 464 U.S. at 211; Exxon I, 88 F.3d at 970; Exxon, 40 Fed. Cl. at 78. Consequently, with the enactment of the Tax Reduction Act of 1975, Pub.L. No. 94-12, § 501, 89 Stat. 26, 47-53 (March 29, 1975), Congress repealed the allowance for percentage depletion, as it applied to the major integrated oil and gas companies, subject only to certain narrow exceptions. Effective January 1, 1975, with application to taxable years ending after December 31, 1974, newly enacted I.R.C. § 613A provided:

SEC. 613A. LIMITATIONS ON PERCENTAGE DEPLETION FOR OIL AND GAS.

(a) GENERAL RULE. -- *Except as otherwise provided in this section*, the allowance for depletion under section 611 with respect to any oil or gas well shall be computed *without regard to section 613* [*i.e*., the allowance for percentage depletion].

(b) EXEMPTION FOR CERTAIN DOMESTIC GAS WELLS. --

(1) IN GENERAL. -- The allowance for depletion under section 611 *shall be computed in accordance with section 613* with respect to --

. . . .

(B) *natural gas sold under a fixed contract* . . . .

. . . .

and 22 percent shall be deemed to be specified in subsection (b) of section

613 for purposes of subsection (a) of that section.

I.R.C. §§ 613A(a), (b) (1975) (emphasis added). In furtherance of the general repeal of percentage depletion for oil and gas, pursuant to § 613A(a), *supra*, the 1975 Act also made certain correlative amendments to § 613 of the Code, two of which we note here. First, the 1975 Act struck out former § 613 (b)(1)(A), which listed "oil and gas wells" among the mineral properties qualifying for percentage depletion at a rate of 22 percent. Pub.L. No. 94-12, § 501(b), 89 Stat. 53. Second, consistent with the repealer in § 613A(a), the Act amended § 613(d) to state: "Except as provided in section 613A, in the case of any oil or gas well, the allowance for percentage depletion shall be computed without reference to this section." Id.

Here at bar, Exxon contends that its 1975 sales of gas under the 18 long-term contracts in issue (*i.e*., the 16 TIC contracts and the two contracts with pipeline customers) qualify for percentage depletion under § 613A(b)(1)(B), *supra*, which excepted certain "natural gas sold under a fixed contract" from the repeal of percentage depletion. In short, whereas *all* of Exxon's 1974 natural gas production qualified for percentage depletion in that taxable year, only the gas that Exxon sold pursuant to "fixed contracts" so qualified in 1975. As in effect during the year 1975, the Code defined such a "fixed contract" as follows:

The term "natural gas sold under a fixed contract" means domestic natural gas sold by the producer under a contract, in effect on February 1, 1975, and at all times thereafter before each sale, under which the price for such gas cannot be adjusted to reflect *to any extent* the increase in liabilities of the seller for tax under this chapter by reason of the repeal of percentage depletion. Price increases after February 1, 1975, *shall be presumed* to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by *clear and convincing evidence*.

§ 613A(b)(2)(A) (1975) (emphasis added). The Government concedes that 16 of the 18 long-term contracts in issue met the requirements of the foregoing "fixed contract" exception in 1975. Thus, only the qualification of Exxon's long-term contracts with Houston Lighting & Power Company (HL&P) and Southwestern Electric Power Company (SWEPCO) is contested here at bar. Because, at the threshold, the RMFP determination is our immediate concern, further consideration of whether the HL&P and SWEPCO contracts were "fixed contracts," within the meaning of § 613A(b)(2)(A), *supra*, is deferred to the penultimate section of this opinion.

We conclude this introductory overview of the post-1974 law of percentage depletion, as applicable to integrated producers of natural gas, by noting that in May of 1977, the Secretary issued extensive Treasury Regulations under § 613A, thereby effecting the administrative implementation of the repeal of percentage depletion, including the implementation of the fixed contract exception thereto. T.D. 7487, 42 Fed. Reg. 24,264 (May 13, 1977); Treas. Reg. §§ 1.613A-0 through 1.613A-7. Yet, even in the midst of this comprehensive overhaul of the percentage depletion regulations, Treas. Reg. § 1.613-3(a) -- prescribing the RMFP computation as the exclusive basis for determining an integrated natural gas producer's "gross income from the property" for percentage depletion purposes -- was retained unaltered in the Code of Federal Regulations. Exxon, 40 Fed. Cl. at 80, 89. The implications of the continued efficacy of Treas. Reg. § 1.613-3(a), with respect to the case at bar, have been a fertile source of controversy.

Before turning to the merits respecting the determination of the RMFP, however, clarity of presentation requires that we address two additional background aspects of this litigation. First, we briefly recount the procedural history of Exxon's refund claim for its taxable year 1975, up to and including the court's denial of the Government's pre-trial motion for summary judgment. Thereafter, the court shall explicate, at somewhat greater length, the nature and extent of the evidentiary record compiled at trial.

III. *Procedural History Of Exxon's 1975 Refund Claim*

Exxon timely filed its 1975 consolidated federal income tax return with the Internal Revenue Service on September 15, 1976. In its 1975 tax return, Exxon claimed depletion deductions totaling $82,059,252, with respect to the 369 natural gas properties in issue. Virtually all of this sum was percentage depletion, as opposed to cost depletion.[(11)] Upon audit, the Commissioner disagreed with Exxon's percentage depletion computations, and disallowed $66,676,098 of the 1975 percentage depletion deductions that Exxon had originally claimed with respect to the 369 natural gas properties in issue. The Commissioner's audit adjustment had two components, one pertaining to January of 1975 and the other relating to the last eleven months of 1975. First, the Commissioner disallowed the portion of Exxon's claimed depletable gross income from the property, with respect to gas produced from the 369 properties in issue prior to February 1, 1975, that exceeded Exxon's actual sales revenues for such gas, net of transportation costs and royalties paid by Exxon. Second, the Commissioner disallowed all of Exxon's claimed depletable gross income from the property with respect to gas from the 369 properties that was produced on or after February 1, 1975, and transported through EGS prior to sale. As a consequence of the foregoing adjustments, Exxon's 1975 federal income tax liability increased by the sum of $32,004,527. Exxon paid the $32,004,527 tax deficiency, plus assessed interest.

Thereafter, on June 5, 1990, Exxon filed a timely administrative claim for refund (Form 1120X) with the IRS, seeking a refund of tax allegedly overpaid for 1975, in the sum of $117,787,209. Included within the foregoing sum were refund claims of $32,004,527 and $11,790,788, relating to Exxon's claimed entitlement to a percentage depletion deduction for natural gas sold in 1975, pursuant to contracts purported to qualify under the § 613A(b)(1)(B) "fixed contract" exception to the repeal of percentage depletion. In addition, Exxon timely filed another claim for refund with the IRS on January 8, 1992, seeking a refund of 1975 tax allegedly overpaid in the sum of $40,052,850, of which $695,396 related to additional fixed-contract percentage depletion. The Commissioner allowed none of Exxon's 1975 refund claims relating to percentage depletion and, consequently, by a petition filed with the court on October 30, 1996, Exxon instituted this suit for refund.

On July 30, 1997, the Government filed a motion for summary judgment, pursuant to RCFC 56. In its summary judgment motion, defendant maintained that with respect to post-1974 taxable years, the RMFP method prescribed in Treas. Reg. § 1.613-3(a) *never* applies when percentage depletion is allowable under the § 613A(b)(1)(B) fixed contract exception. Exxon, 40 Fed. Cl. at 80. Rather, argued the Government, when Congress enacted § 613A into law, it "pegg[ed] the allowance for percentage depletion for fixed contract gas . . . to the *actual sales prices in effect on February 1, 1975*." Id. at 81 (quoting Def. MSJ at 23 (emphasis in original)).[(12)] Defendant asserted, further, that "even if the actual sales of natural gas are made after the gas has been converted into a refined product (as in this case), the prices received on those sales (as fixed by the long-term contracts in effect on February 1, 1975) determine the percentage depletion allowance." Id. (quoting Def. MSJ at 24).

By an opinion filed on January 7, 1998, the court denied the Government's summary judgment motion and ordered that the case proceed to trial. Exxon, 40 Fed. Cl. at 93. All of the reasoning behind our denial of the Government's summary judgment motion need not be reiterated herein, but a brief synopsis will lend useful context to the present discussion.(13)

At the outset, the court determined that "the Code and pertinent Treasury Regulations unambiguously direct an integrated natural gas producer to Treas. Reg. § 1.613-3(a) for guidance as to the manner in which its percentage depletion allowance must be computed in post-1974 taxable years." Exxon, 40 Fed. Cl. at 83. Moreover, we took "it as settled that, prior to 1975, Treas. Reg. § 1.613-3(a) validly applied to every case in which an integrated natural gas producer claimed an allowance for percentage depletion, even where the resultant RMFP exceeded the actual selling price of the natural gas in question." Id. at 86 (citing Exxon, 88 F.3d at 975-76, 980). With the foregoing in mind, the court addressed defendant's contention that whenever percentage depletion is allowable under the post-1974 fixed contract exception, the RMFP method prescribed in Treas. Reg. § 1.613-3(a) is inapplicable.

Beyond our general discomfiture over the Government's attempt to repudiate its own Treasury Regulation, Exxon, 40 Fed. Cl. at 88, we noted that Treas. Reg. § 1.613-3(a), due to its legislative character, must be sustained unless the RMFP method prescribed thereunder "produces results which are arbitrary, capricious, or manifestly contrary to the post-1974 statutory percentage depletion scheme." Id. at 86 (citing Chevron, 467 U.S. at 844; Portland Cement, 450 U.S. at 169; Schuler, 109 F.3d at 755). We noted further that, under the foregoing test, the court could evaluate the validity of Treas. Reg. § 1.613-3 (a) narrowly, as applied to the facts of this case, or broadly, by considering whether the RMFP method is facially invalid whenever the post-1974 fixed contract exception applies. Exxon, 40 Fed. Cl. at 83, 86-87.

As to the validity of Treas. Reg. § 1.613-3(a) on an as-applied basis, *i.e.*, in specific relation to Exxon's 1975 percentage depletion allowance, we concluded that such an analysis would necessitate a fact-intensive inquiry into whether the RMFP proposed by Exxon produces a reasonable result. Id. at 87. Even assuming that judicial inquiry into the reasonableness of an RMFP is appropriate in *any* case, given the Federal Circuit's forceful holding to the contrary in Exxon I, 88 F.3d at 980, we were constrained to hold, on the undeveloped record then before the court, that a "case-specific reasonableness analysis raises genuine issues of material fact that cannot be resolved summarily." Exxon, 40 Fed. Cl. at 87. Regarding the facial validity of Treas. Reg. § 1.613-3(a), we noted that there was "not even a scintilla of evidence before the court that Treas. Reg. § 1.613-3(a) systematically causes a material distortion of the 'gross income from the property,'" where percentage depletion is allowable under the post-1974 fixed contract exception. Id. at 88. Further, as discussed above, "the RMFP calculation aims to ensure that an integrated producer is entitled to no greater percentage depletion deduction, for any given quantity of natural gas extracted, than its nonintegrated competitors." Id. at 77 (citing Exxon I, 88 F.3d at 975). Given the foregoing, we reasoned, an inquiry into the facial validity of Treas. Reg. § 1.613-3(a) must consider whether the application of the RMFP method, in cases to which the post-1974 fixed contract exception applies, "would upset the competitive balance that Congress sought to strike between integrated and nonintegrated producers." Exxon, 40 Fed. Cl. at 92. Needless to say, we concluded that "[w]hether Treas. Reg. § 1.613-3(a) systematically places nonintegrated producers at a competitive disadvantage is a question which turns upon complex factual determinations requiring a trial on the merits." Id. at 91.

In short, having determined that an inquiry into the validity of Treas. Reg. § 1.613-3(a), either facially or as applied to the facts of this case, implicated genuine issues of material fact, the court was constrained to hold that summary judgment was inappropriate. Exxon, 40 Fed. Cl. at 87-88, 91, 93. Trial commenced shortly thereafter, on January 26, 1998, and ended on February 13, 1998. We now turn to an overview of the evidentiary record compiled at trial.

IV. *Evidence Presented At Trial*

Fifteen witnesses were called to testify at trial, eight for Exxon and seven on the Government's behalf, and all were qualified by the court as experts in various fields of knowledge relating to the natural gas industry. Fourteen of these experts also submitted written reports, all of which were received in evidence without substantive objection from either party. Moreover, several of the experts, having been employed in the Texas natural gas industry in 1975, testified as to certain factual matters purporting to be within their personal recollection. The proof fell into three broad area: (i) the computation of the RMFP; (ii) the qualification of the HL&P and SWEPCO contracts as "fixed contracts" under § 613A(b)(2)(A); and (iii) the computation of Exxon's total "gross income from the property" (GIFP) qualifying for percentage depletion in 1975. This opinion reaches and decides the first two issues only.(14) Because we take up the evidence pertinent to the HL&P/SWEPCO "fixed contract" issue separately, in the penultimate section of this opinion, the following discussion is confined to the evidence presented by the parties with respect to the RMFP issue.

At trial, Exxon presented evidence purporting to establish each of the three basic elements of the RMFP determination: (i) the relevant market area; (ii) the comparability of the gas produced in such market area to Exxon's gas; and (iii) the qualification of selected sales of comparable gas in such market area as wellhead sales, *i.e*., sales of raw gas made "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). As in Exxon I, 33 Fed. Cl. at 271, Exxon presented an RMFP study prepared by its natural gas pricing expert, Jonathan Ellis. With respect to the gas that Exxon produced from the 369 properties in issue during 1975, Mr. Ellis opined that the relevant market area in 1975 consisted of Texas Railroad Commission Districts 2, 3, 4, 5, and 6.(15) Districts 2 through 6 encompass roughly the eastern third of Texas, including the Texas Gulf Coast, the East Texas region adjoining Louisiana and Arkansas, the southern tip of Texas, and the Houston and Dallas/Fort Worth metropolitan areas.

Based upon a sample of 2,058 transactions alleged to be qualifying sales of comparable gas occurring within the Texas Gulf Coast/East Texas region in 1975, Mr. Ellis opined that for purposes of computing Exxon's 1975 percentage depletion allowance, the RMFP is $0.7645/Mcf.(16) In addition, Mr. Ellis presented three smaller, alternative RMFP samples, subsets of the foregoing, that are summarized later in this discussion. In determining that the 2,058 transactions in his primary sample qualify for inclusion in his RMFP calculation, Mr. Ellis relied, in part, upon 1975 annual reports filed by natural gas pipeline companies with the Federal Power Commission (FPC), the predecessor agency to FERC, and the Gas Utilities Division (GUD) of the Texas Railroad Commission. Mr. Ellis also relied upon certain gas purchase contracts, *i.e*., contracts by which natural gas pipeline companies bought gas from gas producers, obtained from various pipeline companies that operated in the Texas Gulf Coast/East Texas region in 1975, at least where such contract files were available.(17)

As to the comparability of the gas represented in his RMFP sample to the Exxon gas in issue, Mr. Ellis relied upon a study prepared by Roland Pohler, a registered petroleum engineer and Exxon employee of 35 years, now retired. Although his report and testimony focus principally upon the comparability of Exxon's gas to other gas produced throughout the Texas Gulf Coast/East Texas region, Mr. Pohler also addressed the history and operations of EGS, as well as certain technical aspects of natural gas production, transportation, and processing. On the basis of his gas comparability study, Mr. Pohler opined that the Exxon gas production in issue was comparable or superior to the gas represented in the Ellis RMFP study.

Additional support for Mr. Pohler's conclusion was furnished by Jeff Buie, Durland Eakin, and John Hague, each of whom was employed by a major natural gas pipeline company operating in the Texas Gulf Coast/East Texas region in 1975 -- Houston Pipe Line Company (HPL), Lo-Vaca Gathering

Company, and United Gas Pipe Line Company, respectively.[18] Messrs. Buie, Eakin, and Hague each opined that if the Exxon gas committed to the 18 long-term contracts in issue had been available for sale on the open market in 1975, such gas would have brought the highest price offered by pipeline companies operating in the Texas Gulf Coast/East Texas region. Mr. Buie also testified, in support of Mr. Ellis' determination of the relevant market area, *supra*, that gas producers in the Texas Gulf Coast/East Texas region considered the pipeline companies in that region to be a distinct market for their gas in 1975. Moreover, Messrs. Buie, Eakin, and Hague assisted Mr. Ellis by reviewing gas purchase contract files and other business records obtained from their respective former employers, *i.e.*, HPL, Lo-Vaca, and United, for the purpose of identifying transactions qualifying for inclusion in the RMFP computation.

In addition to the aforementioned experts, Exxon also called C. Ronald Platt, a registered professional engineer with over 35 years of experience relating to the evaluation, development, production, and operation of oil and gas properties. Mr. Platt submitted a study that purports to identify each of the wells that produced the gas represented in Mr. Ellis' 2,058-transaction RMFP sample. Further, Mr. Platt's study attempts to quantify the value that a producer adds to its natural gas, after extraction but prior to sale, by performing such functions as transportation, compression, and dehydration of the gas.[19] As discussed below, the RMFP of $0.7645/Mcf computed by Mr. Ellis reflects certain adjustments made in reliance upon Mr. Platt's study.

Responding to Exxon's RMFP case, the Government presented its own RMFP study, prepared by Ronald Robles, an IRS revenue agent engineer since 1982. Unlike Mr. Ellis, Mr. Robles gave no definitive opinion regarding a single RMFP that, in his view, should apply to the 1975 Exxon gas production in issue. Rather, Mr. Robles presented three different RMFP computations, of which two yield an RMFP of $0.34/Mcf, and the other yields an RMFP of $0.36/Mcf. Mr. Robles' three RMFP computations are based upon 1,925 transactions (in one case, only 1,915 such transactions are used) that purport to be wellhead sales. In ascertaining whether those 1,925 transactions qualified as wellhead sales, Mr. Robles relied upon the same sources of information that Exxon's experts used, *i.e.*, 1975 FPC and GUD annual reports filed by pipeline companies, and the gas purchase contract files that Exxon had obtained from various pipeline companies.

Mr. Robles based his RMFP computations upon a relevant market area defined as the entire State of Texas. Pursuant thereto, Mr. Robles relied upon the opinion of Theodore Welp, a retired IRS geologist, that the entire State of Texas constituted a single market area for natural gas in 1975. As to whether natural gas produced throughout the State of Texas in 1975, as represented in Mr. Robles' RMFP study, was comparable to the gas produced by the 369 Exxon properties in issue, located in the Texas Gulf Coast/East Texas region, the Government presented no gas comparability study akin to the study Mr. Pohler prepared for Exxon. Rather, the Government relies upon Mr. Welp's bare opinion that, for purposes of computing an RMFP, all gas produced in the State of Texas is comparable.[20]

The remainder of the Government's RMFP case was directed toward rebutting various aspects of the conclusions reached by Exxon's experts. Donald Nicol and Bates Martin, both registered professional engineers, joined with Mr. Robles in attacking the standards that Mr. Ellis developed to identify 2,058 transactions that purportedly qualify for inclusion in the RMFP calculation, as well as the conclusions that Messrs. Buie, Eakin, and Ellis formed upon reviewing the various pipeline company contract files in evidence.[21] Moreover, the Government called Warren Edmonds, the deputy director of the Federal Energy Regulatory Commission's Office of Pipeline Regulation, for the purpose of demonstrating that Mr. Ellis' standards are inconsistent with the definition of a wellhead sale prescribed by FERC regulations. Mr. Martin also sought to debunk Mr. Pohler's gas comparability study, assailed Mr. Platt's well identification study, and challenged the accuracy of Mr. Platt's estimates of the value added to natural gas when the producer transports, compresses, or dehydrates such gas prior to sale.

In short, the trial of this case presented a classic "battle of experts" with sharply opposing opinions. The intensity of this clash of warring opinions is concisely summarized by comparing the multiple RMFP computations that each litigant has presented to the court, as follows:

Description Of RMFP Sample	Number Of Transactions	Total Volume Of Gas (Mcf)	Total Value Of Gas ($)	Volume-Weighted Average Price (proposed RMFP)[22]
For Exxon:				
Primary sample	2,058	764,464,493	584,416,403	$0.7645/Mcf[23]
Subsample #1	288	120,293,627	98,672,715	0.8203/Mcf
Subsample #2	56	36,697,547	28,562,035	0.7783/Mcf
"Fixed contract" subsample	460	127,136,289	77,849,167	0.6123/Mcf
"Pristine" subsample	22	8,477,122	6,897,978	0.8137/Mcf[24]

Description Of RMFP Sample	Number Of Transactions	Total Volume Of Gas (Mcf)	Total Value Of Gas ($)	Volume-Weighted Average Price (proposed RMFP)
For the Government:				
Primary sample	1,925	1,183,770,526	408,109,009	$0.3448/Mcf
"Expanded" sample	1,925	1,238,819,423	442,575,748	0.3573/Mcf
"Fixed contract" subsample	1,915	1,178,632,915	399,689,448	0.3391/Mcf.

As the foregoing tabulation illustrates in striking fashion, the disparity between the respective RMFPs calculated by Exxon and the Government, here at bar, is simply enormous.(25)

Exxon's motive in presenting five different RMFP calculations is clear. What Exxon seeks to address is the possibility that the court might reject Mr. Ellis' 2,058-transaction primary RMFP sample, on the ground that some of the transactions included therein fail to qualify for consideration in the RMFP computation. Indeed, as explained, *infra*, we do reject Mr. Ellis' primary RMFP sample, on precisely that ground. Having apparently foreseen this contingency, Exxon points out that it is nonetheless feasible for the court to calculate a valid RMFP on the basis of a *subsample* made up of the remaining qualified transactions. Thus, so as to impress upon the court the ready availability of alternative RMFP computations to choose from, Exxon has presented four subsamples made up of purported qualifying transactions. We shall address all five of Exxon's RMFP computations, as well as the Government's three RMFP computations, in due course, upon reaching the merits of the RMFP issue.

Exxon's litigation strategy is, of course, firmly rooted in Exxon I. Then, as now, Mr. Ellis presented a huge sample of allegedly qualified transactions -- 2,228 transactions, to be exact -- for the trial court's consideration in determining the 1974 RMFP. Exxon I, 33 Fed. Cl. at 271-72. Grave flaws were evident, however, in the criteria that Mr. Ellis used to select his 2,228 transactions. Specifically, the court found that in many of the transactions selected by Mr. Ellis, the producer had added value to the gas, prior to sale, by means of transportation, compression, or dehydration. Id. at 275. The court noted, further, that courts historically have based the RMFP computation upon comparable "sales made at the 'well mouth' or at the 'wellhead or separator,'" id. at 277,(26) but never upon the value added to the gas by post-production activities such as transportation, compression, or dehydration. Id. at 275-77 (citing Cannelton, 364 U.S. at 88; Panhandle, 187 Ct. Cl. at 150-51, 227, 236, 408 F.2d at 704; Hugoton I, 161 Ct. Cl. at 274, 316, 315 F.2d at 869, 892; Brea Cannon Oil Co. v. Commissioner, 77 F.2d 67, 69-70 (9th Cir.), cert. denied, 296 U.S. 604 (1935); Consumers, 78 F.2d 161; Greensboro, 79 F.2d 701; Shamrock, 35 T.C. at 989, 1030, 1037). Therefore, given the foregoing, the court held that transactions involving transportation, compression, or dehydration of the gas prior to sale, had to be excluded from the 1974 RMFP computation. Exxon I, 33 Fed. Cl. at 275, 277. Moreover, due to the evident impracticability of parsing a vast sample of 2,228 transactions, in order to ascertain which transactions involved no transportation, compression, or dehydration of the gas prior to sale, the court held that Exxon had failed to carry its burden of proving an RMFP. In so holding, the court stated:

The vastness of Exxon's sample hindered rather than helped the court determine the

accuracy of the proposed RMFP. A reasonable number of sales that had been sufficiently analyzed to demonstrate that the sales constituted "a fair selection of contracts" appropriate for RMFP determinations, would have been more persuasive. Therefore, the court concludes that Exxon has not met its burden of proving by a preponderance of the evidence . . . an acceptable RMFP based on the facts of this case.

Exxon I, 33 Fed. Cl. at 278. See also id. at 274 ("The sheer number of transactions and lack of data as to each transaction leaves the court unable to ascertain whether the sales truly are sales of raw gas in the immediate vicinity of the well."), 275 (to same effect), 277 (same).

On appeal, the Federal Circuit affirmed, as not clearly erroneous, the trial court's holding that the RMFP computation must exclude transactions in which the value of the gas was enhanced, prior to sale, by transportation, compression, or dehydration. Exxon I, 88 F.3d at 977-78. Having expressly affirmed the trial court's decision on this point, the Federal Circuit went on to suggest that it would be "preferable" to cure such tainted transactions by subtracting the costs of transportation and dehydration (and, by necessary implication, compression) from the sales price of the gas. Id. at 978 (citing Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718).

Here at bar, consistent with the Federal Circuit's express holding in Exxon I, Exxon has presented two RMFP computations which purport to be based upon transactions that involved no transportation, compression, or dehydration of the gas prior to sale -- Exxon's 56-transaction subsample and Exxon's "pristine," 22-transaction sample, *supra*. Further, so as to cover all the bases, Exxon has adopted the Federal Circuit's "preferable" method, in connection with its primary, 2,058-transaction RMFP sample, its 288-transaction subsample, and its 460-transaction "fixed contract" subsample, meaning that the sales price of the gas in many of the transactions included therein has been adjusted downward by the estimated costs of any transportation, compression, or dehydration related to such transactions, as determined by Mr. Platt.(27)

Inasmuch as its primary RMFP computation is based upon 2,058 transactions, Exxon is plainly unmoved by the trial court's well-considered remarks in Exxon I, relative to the burdens that a huge RMFP sample places upon the process of adjudicating RMFP cases by trial. See Exxon I, 33 Fed. Cl. at 274, 275, 277, 278. Exxon's indifference is, no doubt, attributable to the fact that in Exxon I, although the Federal Circuit acknowledged that the "calculation of the RMFP is a difficult and sometimes onerous task," 88 F.3d at 976, it nonetheless concluded that the daunting nature of that task does not excuse the trial court from attempting to identify transactions that are properly includible in the RMFP calculation, even if such qualifying transactions are effectively buried within a conglomeration of over 2,000 other transactions. Moreover, the Federal Circuit held that the Court of Federal Claims had committed reversible error "by truncating its RMFP analysis thus not reaching the issue of whether Exxon's [RMFP] study contained *any* valid transactions from which an RMFP could be determined." Id. at 979 (emphasis added).

Here at bar, of course, we are bound by the Federal Circuit's directive in Exxon I. Thus, if the record contains *any* competent evidence of qualifying sales of comparable gas within the relevant market area in 1975 -- even if the record is voluminous, burdensome to work with, and inclusive of many nonqualifying transactions -- the court must determine an RMFP from whatever probative evidence is at hand. Yet, the court feels constrained to observe that we are faced with much the same dilemma as the trial court in Exxon I, and it is with no less apprehension that we approach the 2,058 transactions that Exxon has presented for consideration.(28)

At trial, in support of the opinions and reports of its expert witnesses, Exxon offered a staggering volume of documentation into evidence, virtually all of which the Government acquiesced to, surprisingly, without objection, by stipulating that such documents were admissible. Said documentation amounts to roughly 300,000 pages, enough to fill 268 large document storage boxes.(29) Most of this documentary bulk is attributable to two exhibits that contain numerous pipeline company gas purchase contract files, corresponding to most of the 2,058 transactions in Exxon's RMFP sample. Those two exhibits, PX 14a and PX 14b, fill 84 and 154 document storage boxes, respectively. Despite the firm assurances of both parties that the entire contents of PX 14a and PX 14b are material and relevant to the outcome of this case, the court soon found, upon retiring to consider and weigh the evidence adduced at trial, that such contract files contain vast quantities of irrelevant surplusage.(30)

Another troubling aspect of Exxon's 2,058-transaction RMFP sample is that only a minuscule fraction of those 2,058 transactions were actually mentioned at trial, and in even fewer cases were the underlying pipeline company contract files meaningfully examined through the direct testimony and cross-examination of a witness.(31) Only 10 such transactions were the subject of testimony by witnesses purporting to have direct first-hand knowledge, dating to 1975, that is probative of the qualification of such transactions for inclusion in the RMFP computation. Much of this supposed eyewitness testimony was speculative or otherwise inconclusive, however, as it was concerned with transactions that took place 23 years prior to the trial of this case.(32) Thus, virtually *all* of the meager testimonial record concerning the qualification of Exxon's 2,058 transactions for inclusion in the RMFP computation is pure, unadulterated, opinion testimony.

Notwithstanding all of the foregoing circumstances, the court has dutifully labored over the documentary record in search of qualifying transactions,[(33)] in compliance with the Federal Circuit's directive in Exxon I, 88 F.3d at 979. Having justifiably ventilated our warm concerns over the state of the evidentiary record in this case, we now turn to the merits of the case at bar. First, we address the relevant market area, with respect to the 369 Exxon properties in issue. Next, the court shall examine the issue of gas comparability and, thereafter, undertake the selection of a sample of qualified transactions on which to base the RMFP computation. Lastly, we shall consider whether the HL&P and SWEPCO contracts were "fixed contracts," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A).

DISCUSSION

In every federal income tax refund suit, the taxpayer must carry the heavy burden of overcoming the presumption that the Commissioner's determinations are correct as a matter of law. Welch v. Helvering, 290 U.S. 111, 115 (1933); Transamerica Corp. v. United States, 902 F.2d 1540, 1543 (Fed. Cir. 1990). As a consequence, initially, Exxon must go forward with sufficient probative evidence to support a finding contrary to the Commissioner's determination. Danville Plywood Corp. v. United States, 899 F.2d 3, 7 (Fed. Cir. 1990). In addition thereto, Exxon must carry its ultimate burden of affirmatively establishing each operative element of its 1975 refund claim by a preponderance of the evidence. Transamerica, 902 F.2d at 1543; Tucker v. United States, 8 Cl. Ct. 180, 186 (1985).

Further, it must be remembered that the taxpayer's burden weighs especially heavy when the merits of its suit for refund hinge upon the claimed entitlement to an income tax deduction. This is clearly so, for it is firmly settled that income tax deductions are a matter of legislative grace and are to be narrowly construed. INDOPCO, Inc. v. Commissioner, 503 U.S. 79, 84 (1992); Commissioner v. Sullivan, 356 U.S. 27, 28 (1958); New Colonial Ice Co. v. Helvering, 292 U.S. 435, 440 (1934); Schuler, 109 F.3d at 755; Iowa Southern Util. Co. v. United States, 841 F.2d 1108, 1113 (Fed. Cir. 1988). As the Supreme Court has repeatedly admonished, the foregoing maxim is particularly apposite to the allowance for percentage depletion, which "first came into the tax structure in 1926 and has been consistently regarded as a matter of legislative grace." Paragon Jewel Coal Co., Inc. v. Commissioner, 380 U.S. 624, 631 (1965). See also United States v. Swank, 451 U.S. 571, 577, 579 n.11 (1981); Parsons v. Smith, 359 U.S. 215, 219 (1959); Commissioner v. Southwest Exploration Co., 350 U.S. 308, 312 (1956); Anderson v. Helvering, 310 U.S. 404, 408 (1940); Helvering v. Bankline Oil Co., 303 U.S. 362, 366 (1938). Moreover, where the taxpayer's proof depends largely, if not almost exclusively, upon the opinions of its expert witnesses, as in the case at bar, such opinion testimony is not conclusive and binding upon a court sitting as the trier of fact. Dayton Power & Light Co. v. Public Util. Commission, 292 U.S. 290, 299 (1933); Sartor v. Arkansas Natural Gas Corp., 321 U.S. 620, 627-29 (1944); Sternberger v. United States, 185 Cl. Ct. 518, 535-36, 401 F.2d 1012, 1016 (1968) (*per curiam*) ("Even uncontradicted opinion testimony is not conclusive if it is intrinsically nonpersuasive."); Mims v. United States, 375 F.2d 135, 140 & n.2 (5th Cir. 1967).[(34)] With the aforesaid familiar principles in mind, we first consider whether Exxon has carried its burden of proving the relevant market area for purposes of computing the RMFP, relative to the taxable year 1975, with respect to the 369 Exxon properties in issue.

I. *Relevant Market Area In 1975*

The fundamental principles that guide our determination of the relevant market area were first laid down by the Court of Claims in the Hugoton I and Hugoton II decisions, *supra*, and later refined in the Panhandle case. In the latter decision, the Court of Claims stated that in determining the relevant market area in an RMFP case, "[t]here are only two things required under the Hugoton case: "(1) the area should be representative of the taxpayer's production, and (2) comparable gas should be used." Panhandle, 187 Ct. Cl. at 155; 408 F.2d at 706 (citing Hugoton II, 172 Ct. Cl. at 463-65, 349 F.2d at 430-31). Under the aforementioned standard, it is evident that the geographical definition of the relevant market area is closely intertwined with, and must be considered in conjunction with, the gas comparability issue. Stated differently, no geographical area can qualify as the *relevant* market area, for purposes of computing the RMFP, unless it is also demonstrated that the gas produced and sold within that area is "'reasonably or substantially similar'" to the taxpayer's gas. Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (quoting Phillips Petroleum Co. v. Bynum, 155 F.2d 196, 198 (5th Cir.), cert. denied, 329 U.S. 714 (1946)).

For this reason alone, we must reject the Government's contention that the relevant market area in 1975 was the entire State of Texas. As explained above, the Government *failed to present a statewide gas comparability study* in support of its position. Instead, the Government's market area expert, Mr. Welp, merely voiced a naked *opinion* that, for purposes of computing the RMFP, here at bar, all gas produced throughout the State of Texas in 1975 was comparable. More importantly, the Government's total failure of proof on the issue of gas comparability, on a *statewide* basis, completely invalidates Mr. Robles' three RMFP computations, all of which are premised on a statewide market area.

Given the foregoing, the singularly important question to be answered is whether Exxon has established, by a preponderance of the evidence, that for purposes of computing an RMFP with respect to Exxon's 1975 gas production from the 369 properties in issue, the relevant market area was, in fact, the Texas Gulf Coast/East Texas region, as delineated by Texas Railroad Commissions 2 through 6, inclusive. As noted above, a later section of this opinion shall address Exxon's proof on the gas comparability issue. However, first we must consider whether the Texas Gulf Coast/East Texas region was geographically "representative of the taxpayer's production" in issue. Panhandle, 187 Ct. Cl. at 155; 408 F.2d at 706. We begin with an overview of the natural gas industry in the Texas Gulf Coast/East Texas region, as it existed in 1975.

A. *The Natural Gas Industry In The Texas Gulf Coast/East Texas Region In 1975*

Within the Texas Gulf Coast/East Texas region, natural gas is principally found in the Houston Embayment, the Rio Grande Embayment, and the East Texas Basin. The terms "embayment" and "basin" are used in the industry to describe large geographic areas containing many natural gas "fields." Generally, a "field" is a localized geographic area that overlays a single underground reservoir of natural gas, or multiple such reservoirs in close proximity to another. The Houston Embayment lies in the area surrounding the city of Houston, in Texas Railroad Commission District 3. Situated to the southwest of and adjacent to the Houston Embayment, the Rio Grande Embayment encompasses the southern tip of Texas, including the southern end of the Texas Gulf Coast, in Districts 2 and 4. As noted above, roughly 95% of the Exxon gas in issue came from properties located in the foregoing areas, *i.e.*, the gas processed in Exxon's King Ranch, Katy, Anahuac, Pledger, Clear Lake, and Lovell Lake plants. The East Texas Basin is located roughly 100-150 miles north of Houston, in District 6 and the southeastern portion of District 5, and also extends into northwestern Louisiana. About 5% of the Exxon gas in issue was East Texas gas, *i.e.*, the gas processed in Exxon's Hawkins and East Texas plants. See Exxon I, 33 Fed. Cl. at 259 (similar findings as to 1974). Outside of the Texas Gulf Coast and East Texas, the other major gas-producing regions in Texas are: (i) the Fort Worth Basin, to the north, west, and southwest of the city of Fort Worth; (ii) the Permian Basin in West Texas, which extends into southeastern New Mexico as well;

and (iii) the Hugoton Embayment in the northern Texas Panhandle, which also extends northward throughout the Oklahoma Panhandle and southwestern Kansas.[(35)]

In 1975, an extensive network of natural gas pipeline systems covered the Texas Gulf Coast area, connecting the gas fields located therein with gas consumers. Such gas pipelines, EGS included, ran generally in a southwest-to-northeast direction and were concentrated in a geographical corridor extending about 60 to 100 miles inland from the Gulf Coast, commonly known as "Pipeline Alley." East Texas also contained many gas pipelines, albeit in somewhat lesser number and density than along the Gulf Coast, including the East Texas segment of EGS.

Natural gas pipeline companies in the Texas Gulf Coast/East Texas region (and elsewhere in the United States) fell into two distinct classes in 1975 -- interstate pipelines and intrastate pipelines. Interstate pipelines transported gas in interstate commerce, *i.e.*, for delivery to consumers situated both within and without Texas, and such gas was, therefore, subject to regulation by the Federal Power Commission (FPC). Conversely, intrastate pipelines, including EGS, transported gas solely within the State of Texas and fell within the regulatory jurisdiction of the Gas Utilities Division (GUD) of the Texas Railroad Commission. Producers and pipelines doing business in the intrastate market sought to avoid any commingling of their gas with interstate gas, because that would cause such gas to become interstate gas and, thus, subject to FPC price controls. Exxon I, 33 Fed. Cl. at 259-60 & n.8 (similar findings as to 1974). See also Hugoton II, 172 Ct. Cl. at 451-52, 457 & n.20, 458 & n.21, 465, 349 F.2d at 421-22, 426 & nn. 20-21, 431 (noting distinction between interstate and intrastate gas).[(36)]

As of 1975, most of the aforementioned pipelines in the Texas Gulf Coast/East Texas region had been in place since the late 1950s or early 1960s. In the late 1960s and early 1970s, however, the burgeoning demand for natural gas along the Texas Gulf Coast, in and about Houston, spurred the construction of pipelines to transport gas from the Permian Basin, in West Texas, to the Texas Gulf Coast.[(37)] By 1975, about 25% to 30% of the gas produced in the Permian Basin was being transported eastward to the Texas Gulf Coast. Such Permian Basin gas constituted roughly 15% of the total gas available in the Texas Gulf Coast/East Texas region in 1975, taking into account the gas production indigenous to that region.[(38)]

Due to the many pipeline companies operating in the Texas Gulf Coast/East Texas region in 1975, natural gas producers in that region had a ready market in which to sell their gas. Moreover, those pipeline companies could readily resell such gas, because the Texas Gulf Coast encompassed the largest gas consuming market in Texas -- the Houston metropolitan area, which experienced rapid population growth in the 1970s, and the vast petrochemical industry complexes located along the Gulf Coast in the general vicinity of Houston. Due to the foregoing, Texas was not only the leading producer of natural gas in the continental United States in the 1970s, but was also the largest gas *consuming* state.[(39)]

From a pricing perspective, two distinct characteristics marked the natural gas industry in the Texas Gulf Coast/East Texas region, and elsewhere in the nation, in 1975. First, as with energy prices generally in the 1970s, natural gas prices manifested a steep upward trend in 1975, in a continuation of the price trend noted in Exxon I, 88 F.3d at 970 ("The market price of natural gas doubled in 1973, and doubled again in 1974."). Cf. Commissioner v. Engle, 464 U.S. at 211 (noting sharp upswing in energy prices during the 1970s). Second, this upward price trend was far more pronounced in the case of intrastate gas than in the case of interstate gas, due to the existence of federal price controls on the latter. Both phenomena are thoroughly documented in the record here at bar. For example, the weighted average cost of gas purchased (WACOG) by Houston Pipe Line Company (HPL), one of the largest Texas intrastate pipeline companies, was \$1.31/Mcf in 1975, whereas HPL's 1974 WACOG was only \$0.70/Mcf.[(40)] Further, *current* intrastate market prices in 1975, as reflected in *new* gas purchase contracts (or in old contracts for which the price had been renegotiated upward, a practice explained more fully below), ranged as high as

$1.90 to $2.10 per Mcf.(41)

Conversely, due to federal price controls, the price of Texas Gulf Coast/East Texas gas sold into *inter*state commerce experienced a relatively modest increase in 1975, as evidenced by the fact that United Gas Pipe Line Company, a major interstate pipeline company, had a 1975 WACOG of only $0.42/Mcf, relative to such gas.(42) Given the immense disparity between the prices that the FPC allowed the interstate pipelines to pay, and the higher, unregulated prices that the intrastate pipelines could offer, the interstate pipelines were effectively frozen out of the bidding for purchases of new gas supplies. See Exxon I, 33 Fed. Cl. at 260 ("Interstate pipelines, restricted by the FPC in what they could pay for gas, were basically priced out of the market [in 1974]."). This, in turn, caused a nationwide shortage of natural gas in the early 1970s, which continued into 1975.(43) Moreover, the aforesaid shortage was exacerbated by surging demand in the intrastate gas market, driven by the booming population and industrial centers of the Texas Gulf Coast, and at the national level, due to fears of a permanent energy shortage, caused by the oil embargo imposed by the Organization of Petroleum Exporting Countries (OPEC) following the 1973 Yom Kippur War. Id. at 260 (similar findings as to 1974). See also Engle, 464 U.S. at 211 (noting relationship between the Arab oil embargo and rising energy prices).

Given conditions of restricted supply and swelling demand, intrastate pipeline companies in the Texas Gulf Coast/East Texas region competed vigorously in bidding for new supplies of gas, giving rise to a "sellers' market" in which gas producers exercised substantial negotiating leverage with respect to potential gas buyers, *i.e*., pipeline companies. See Exxon I, 33 Fed. Cl. at 261 (noting that "by 1974, many [gas] producers could practically write their own deals"). The fierce competition among intrastate pipeline companies for new gas supplies fed upon itself, sending intrastate gas prices ever higher, as a result of the price redetermination clauses contained in most gas purchase contracts in effect in 1975. A typical price redetermination clause allowed the producer to reprice its gas periodically, *i.e*., annually, semiannually, or quarterly, to the average of the two or three highest prices observed for other gas sales to pipelines within a specified geographical area, typically consisting of one or more Texas Railroad Commission Districts.(44) See Exxon I, 33 Fed. Cl. at 261 (explicating such price redetermination clauses). Based upon his employment as a gas purchase contract administrator with Lo-Vaca Gathering Company, a large intrastate pipeline company, during the 1970s, Mr. Eakin testified that such price redeterminations accelerated the general upward trend in the market price of intrastate gas, creating "a self-feeding spiral with no end."(45) In other words, every time a new gas purchase contract was concluded, or an existing contract price was redetermined, that set an informal regional "floor" price below which no other sales of gas in the intrastate market would fall. Thereafter, upon the discovery of a new supply of gas, competing pipelines would bid to purchase such gas, with the winning bidder inevitably having to offer a price exceeding the most recently established regional floor price. Once the newly negotiated, higher price being paid for that new gas supply became generally known in the regional market, another round of price redeterminations under pre-existing contracts would be triggered, and so on.(46)

In short, from the perspective of a natural gas producer, the Texas Gulf Coast/East Texas region was characterized by a strong regional demand for such gas, active competition among numerous potential buyers of such gas, *i.e*., the intrastate pipeline companies operating in the region, and a steep upward price trend. We turn now to consider the parties' contentions regarding the definition of the relevant market area.

B. *Contentions Of The Parties*

Exxon advances three arguments in support of its basic contention -- that for purposes of computing an RMFP with respect to Exxon's 1975 gas production from the 369 properties in issue, the relevant market area was the Texas Gulf Coast/East Texas region, as delineated by Texas Railroad Commissions 2 through 6, inclusive. First, Exxon maintains that under the doctrine of collateral estoppel, the holding in Exxon I, as to the relevant market area in 1974, *supra*, conclusively establishes the relevant market area for 1975, unless it is shown that the pertinent facts materially changed between 1974 and 1975. According to Exxon, the Government has the burden of proving that such a material factual difference existed, under the holding in McMullan v. United States, 231 Ct. Cl. 378, 384, 686 F.2d 915, 919 (1982).

Second, Exxon argues that binding precedent strongly discourages relitigation of the relevant market area determination in RMFP cases. Specifically, in the Panhandle case, having noted that the Government's position would cause the relevant market area to be "subject to revision year after year," the Court of Claims declared that "[i]t is only reasonable that the plaintiff have some assurance that it can file annual tax returns without having to periodically relitigate the size, shape, and depth of the area from which its gross income from the property is to be ascertained." Panhandle, 187 Ct. Cl. at 159, 408 F.2d at 709. Lastly, Exxon asserts that the doctrines of collateral estoppel and *stare decisis* notwithstanding, it presented evidence at trial establishing that the Texas Gulf Coast/East Texas region was the relevant market area in 1975.

As noted above, the Government's position is simply that the entire State of Texas was the relevant market area in 1975. We have already held herein that the Government's position cannot be sustained, given its failure to present a statewide gas comparability study. Nonetheless, in the following discussion, the court shall consider whether the Government, in fact, presented any evidence tending to rebut Exxon's case with respect to the relevant market area determination.

C. *Discussion*

1. *Collateral Estoppel*

Under the doctrine of collateral estoppel, also known as issue preclusion, "once a court has decided an issue of fact or law necessary to its judgment, that decision is conclusive in a subsequent suit based on a different cause of action involving a party to the prior litigation." United States v. Mendoza, 464 U.S. 154, 158 (1984). See also Montana v. United States, 440 U.S. 147, 153 (1979); Commissioner v. Sunnen, 333 U.S. 591, 597-98 (1948); Texas Instruments Inc. v. Cypress Semiconductor Corp., 90 F.3d 1558, 1568 (Fed. Cir. 1996), cert. denied, 520 U.S. 1228 (1997). The purpose of the doctrine of collateral estoppel is to "relieve parties of the cost and vexation of multiple lawsuits, conserve judicial resources, and, by preventing inconsistent decisions, encourage reliance on adjudication." Allen v. McCurry, 449 U.S. 90, 94 (1980). However, justice and fairness mandate that the doctrine of collateral estoppel is not a blunt, ponderous tool given to indiscriminate application.

Difficulty sometimes arises . . . in delineating the issue on which litigation is, or is not, foreclosed. The problem involves a balancing of important interests: on the one hand a desire not to deprive a litigant of an adequate day in court; on the other hand, a desire to prevent repetitious litigation of what is essentially the same dispute.

In re Freeman, 30 F.3d 1459, 1465 (Fed. Cir. 1994) (citing Restatement (Second) of Judgments § 27 cmt. c (1980)). Therefore, before collateral estoppel is held to apply, the court must determine that four conditions are satisfied, as follows:

Collateral estoppel is appropriate only if: (1) the issue to be decided is identical to the one decided in the first action; (2) the issue was actually litigated in the first action; (3) resolution of the issue was essential to a final judgment in the first action; and (4) the parties had a full and fair opportunity to litigate the issue in the first action.

Arkla, Inc. v. United States, 37 F.3d 621, 624 (Fed. Cir. 1994). Mindful of the foregoing, this court has given the trial and appellate opinions in Exxon I the most careful scrutiny, in order to ascertain the nature and scope of the issues that were actually litigated and decided in those proceedings. Moreover, at the request of the parties, we have also taken limited judicial notice of their respective appellate briefs, as filed with the Federal Circuit in Exxon I, solely for the purpose of addressing Exxon's collateral estoppel arguments.

At the outset, in determining whether collateral estoppel bars the relitigation of the relevant market area issue in the case at bar, relative to 1975, the court must consider what the precise holding was in Exxon I, with respect to the relevant market area in 1974. Inasmuch as Exxon did not appeal the trial court's holding as to the relevant market area in 1974, we must seek the answer to the aforesaid question in the trial court's opinion. It is true, as Exxon points out, that the trial court in Exxon I held that the relevant market area in 1974 was the "Texas Gulf Coast and East Texas." Exxon I, 33 Fed. Cl. at 262. Exxon contends, further, that its proposed 1975 market area, consisting of Texas Railroad Commission Districts 2 through 6, inclusive, is the same market area as that adopted in Exxon I. However, Exxon's position is at odds with a plain reading of the trial opinion in Exxon I, wherein the court expressly found that the "Texas Gulf Coast region consists of Texas Railroad Commission Districts 2, 3, 4 and adjacent offshore areas" and that "East Texas includes Railroad Commission District 6." Exxon I, 33 Fed. Cl. at 259. Nowhere in the court's opinion was District 5 mentioned. The court also found that of the 482 Exxon gas properties in dispute in the 1974 litigation, 172 such properties were located in Districts 2, 3, and 4, and 310 properties were located in District 6. Id. Again, nowhere was District 5 mentioned. Thus, Exxon's contention that its proposed 1975 market area is identical to the 1974 market area adopted in Exxon I is plainly incorrect. Given the foregoing, we must, and do, reject Exxon's contention that, under the doctrine of collateral estoppel, Exxon I conclusively establishes that Railroad Commission Districts 2 through 6, inclusive, were the relevant market area in 1975.

Even assuming, *arguendo*, that the relevant market area adopted in Exxon I was the same market area that Exxon advocates, here at bar, we would still find Exxon's collateral estoppel argument without merit, on this record. One of the indispensable elements of collateral estoppel, as to which the proponent thereof has the burden of proof, is that "the issue to be decided [in the present case] is *identical* to the one decided in the first action." Arkla, 37 F.3d at 624 (emphasis added). The Supreme Court has construed the foregoing requirement rather strictly in the context of federal income tax litigation relating to separate taxable years, as follows:

[W]here two cases involve income taxes in different taxable years, collateral estoppel must be used with its limitations carefully in mind so as to avoid injustice. It must be confined to situations where the matter raised in the second suit is *identical in all respects* with that decided in the first proceeding and where the *controlling facts and applicable legal rules remain unchanged*. . . . If the legal matters determined in the earlier case differ from those raised in the second case, collateral estoppel has no bearing on the situation. . . . And where the [factual] situation *is vitally altered* between the time of the first judgment and the second, *the prior determination is not conclusive*.

Commissioner v. Sunnen, 333 U.S. 591, 599-600 (1948) (emphasis added). However, when similar issues of fact arise in two tax refund suits involving different tax years, any "factual differences must be *material, i.e., having legal significance*, to prevent operation of collateral estoppel." Arkla, 37 F.3d at 625 (emphasis added) (citing Montana, 440 U.S. at 162). See also Montana, 440 U.S. at 163 (collateral estoppel applied where successive suits involving the same parties were "closely aligned in time and subject matter"); United States v. Stauffer Chemical Co., 464 U.S. 165, 172 (1984) (to same effect). In addition to the foregoing precedents, Exxon cites McMullan, 231 Ct. Cl. at 384, 686 F.2d at 919, for the proposition that it is the Government's burden to establish that collateral estoppel is inapplicable to the case at bar, by showing the occurrence of a material factual change in the relevant market area between 1974 and 1975.

We think Exxon gives McMullan an overbroad reading. As with the case at bar and Exxon I, McMullan presented successive tax refund suits involving different taxable years. In the first case, judgment was entered in the taxpayers' favor on their refund claims for the years 1969-1971. Wilmington Trust Co. v. United States, 221 Ct. Cl. 686, 610 F.2d 703 (1979) (*en banc*). Thereafter, in the second case, relating to the 1972 tax year, the taxpayers contended that collateral estoppel precluded the relitigation of the issues of fact and law previously litigated and decided in Wilmington. McMullan, 231 Ct. Cl. at 380, 686 F.2d at 917. After determining that Wilmington and the case at hand presented materially identical issues, 231 Ct. Cl. at 382-83, 686 F.2d at 918-19, the Court of Claims concluded "that [the Government] has not made an adequate showing that the facts in the present case differ significantly from those in Wilmington." McMullan, 231 Ct. Cl. at 384, 686 F.2d at 919.

Exxon cites, and we have found, no case construing McMullan to mean that the party against whom collateral estoppel is asserted has the burden, *ab initio*, of *disproving* the sameness of the factual issues presented in successive lawsuits. That is not the law, as McMullan itself makes clear. The Court of Claims expressly treated the question of whether the issues of fact and law presented by the two cases were identical as the threshold question, and only upon answering that question in the affirmative did the court turn to the question of whether the Government had shown any material factual differences between the two cases. McMullan, 231 Ct. Cl. at 382, 686 F.2d at 918.[(47)] Thus, as the proponent of collateral estoppel, Exxon undeniably had the initial burden of making out a *prima facie* case that the relevant market area determination here at bar, relative to 1975, involves issues of fact that are materially identical to the factual issues decided pursuant to the relevant market area determination in Exxon I, relative to 1974. If, and only if, Exxon carried that burden at trial, would the burden of going forward with the evidence, in rebuttal of Exxon's *prima facie* case, shift to the Government. We are of the opinion, however, that Exxon has failed to establish that the relevant market area determinations in Exxon I and the present case involve materially identical issues of fact.

In reaching this conclusion, we note that, although Exxon I established that the relevant market area in 1974 was the "Texas Gulf Coast and East Texas," 33 Fed. Cl. at 262, the court most certainly did *not* hold that the Texas Gulf Coast/East Texas region continued to be the relevant market area in post-1974 years. On the contrary, with respect to the periodic price redeterminations that had become common in the Texas intrastate gas market by 1974, Judge Lydon found that the trend was clearly in the direction of statewide pricing, as follows:

Gas purchase/sale contracts, in 1974, also featured most-favored-nation or price redetermination provisions whereby pipelines agreed to raise the price each month to the highest price being paid in the area. During the early 1970s, price redetermination provisions were based on the highest prices in a particular Railroad Commission District for gas sold under "similar terms and conditions." However, by 1974, these clauses were broadened in scope to permit the redetermined price to be the average of the two or three highest prices being paid in Railroad Commission Districts 2, 3, and 4. *Eventually, by 1980, some contracts stipulated that the redetermined price would be based upon the highest price being paid in the entire state of Texas*.

Exxon I, 33 Fed. Cl. at 261-62 (emphasis added) (footnote omitted).

Here at bar, with respect to 1975, Mr. Buie's report and testimony reconfirmed the existence of a trend toward statewide pricing in the Texas intrastate gas market and the eventual emergence, by 1980, of statewide pricing.(48) We think that evidence showing how gas producers and pipeline companies geographically defined the relevant marketplace, for purposes of their periodic price redeterminations, strongly influences the determination of the relevant market area for purposes of the RMFP computation. Therefore, the industry trend away from regional price redeterminations, *i.e*., based upon one to three Railroad Commission Districts, and toward statewide price redeterminations, constitutes powerful evidence that the Texas intrastate gas market was in a state of flux in the mid-1970s. Consistent with the foregoing, the Exxon I court also made the following finding:

By 1972, West Texas had been connected by pipeline to the Gulf Coast, and large reserves could command prices competitive with any other reserves in the state. Transportation and exchange agreements between pipelines also came into more extensive use in the early 1970s, with the result that *the entire state ultimately became the market area* for large reserves.

Exxon I, 33 Fed. Cl. at 261 (emphasis added).

The plain import of the above-referenced findings in Exxon I is that the Texas natural gas industry was not static in the 1974-1975 time frame, as Exxon would have it, but in a state of dynamic transition and, further, that a statewide gas market emerged sometime between the end of 1974 and the year 1980.(50) Clearly the doctrine of collateral estoppel cannot be applied so as to force this court to disregard the possibility that such a statewide market had, in fact, emerged by 1975. This is so because a potential shift in the boundaries of such market area has undeniable legal significance in an RMFP case, given the pivotal importance of the relevant market area determination. Collateral estoppel is inapplicable where factual differences from one taxable year to the next are "material, i.e., having legal significance." Arkla, 37 F.3d at 625. Therefore, the findings in Exxon I as to the relevant market area in 1974 cannot preclude this court from making its own independent findings as to the relevant market area in 1975.

For the sake of completeness, it must be noted that we assign no probative weight to the chorus of hospitable opinion testimony from Exxon's expert witnesses, all to the effect that market conditions affecting gas producers in the Texas Gulf Coast/East Texas region were materially unchanged between 1974 and 1975.(51) As noted above, "[e]ven uncontradicted opinion testimony is not conclusive if it is intrinsically nonpersuasive." Sternberger, 185 Cl. Ct. at 535-36, 401 F.2d at 1016. See also Dayton Power & Light, 292 U.S. at 299; Sartor, 321 U.S. at 627-29; Mims, 375 F.2d at 140 & n.2. None of Exxon's experts gave any credible testimony delineating specific, concrete facts and circumstances that were relevant to their conclusion that market conditions were unchanged between 1974 and 1975. Such bland and conclusory opinion testimony "'carries its own death wound.'" Sternberger, 185 Ct. Cl. at 536, 401 F.2d at 1016 (quoting NLRB v. Robbins Tire & Rubber Co., 161 F.2d 798, 800 (5th Cir. 1947)).

In short, as explained above, there is substantial evidence in the record from which the court may reasonably infer that, from the viewpoint of gas producers in the Texas Gulf Coast/East Texas region in the 1974-1975 time frame, the marketplace was in a state of flux. If courts were to apply collateral estoppel so as to "freeze" the taxpayer's relevant market area in RMFP cases such as this, where the record is replete with evidence suggesting that the marketplace was evolving, that would "create vested rights in decisions that . . . [later] become obsolete or erroneous with time, thereby causing inequities among taxpayers." Sunnen, 333 U.S. at 599. Thus, we are constrained to hold that Exxon I's determination of the relevant market area in 1974 has no preclusive effect with respect to our determination of the relevant market area in 1975.

On similar reasoning, we also find that Exxon places unjustified reliance upon Panhandle, wherein the

Court of Claims observed that a taxpayer using the RMFP method should "have some assurance that it can file annual tax returns without having to periodically relitigate the size, shape, and depth of the area from which its gross income from the property is to be ascertained." Panhandle, 187 Ct. Cl. at 159, 408 F.2d at 709.(52) Panhandle was concerned with RMFP determinations for the years 1952-1956, an era in which the natural gas industry was marked by low, stable market prices and long-term fixed-price contracts. See Panhandle, 187 Ct. Cl. at 132-33, 408 F.2d at 693; Exxon I, 33 Fed. Cl. at 259-60, 262. The Court of Claims, no doubt, reasoned that, in a stable market environment, to compel the taxpayer to relitigate its relevant market area annually is unsound tax policy because it is unreasonable to presume that the taxpayer's relevant market area changes significantly from one year to the next.

Conversely, as explained above, the natural gas market was in a state of upheaval in the 1970s, including the 1974-1975 time frame.(53) We are of the opinion that such circumstances bring another legal principle to the fore -- a principle first enunciated in Hugoton II and later reaffirmed in Panhandle, as follows:

As of this time there has been no attempt to define definitively the [market] area to be considered in computing a representative "market" or "field" price. *We believe that such an all-inclusive rule cannot be laid down* due to the fact that each case arises in its own particular context depending upon the surroundings in which the taxpayer finds himself.

Hugoton II, 172 Ct. Cl. at 464, 349 F.2d at 431 (emphasis added), quoted with approval in Panhandle, 187 Ct. Cl. at 168, 408 F.2d at 714. Accordingly, by holding that Exxon cannot rely upon the 1974 market area adopted in Exxon I, but rather, must relitigate the relevant market area issue anew with respect to 1975, we do no injury to precedent. On the contrary, we merely acknowledge, as we must, that where there is substantial evidence that the marketplace was in a state of dynamic transition, the determination of the taxpayer's relevant market area necessarily must proceed *de novo*.

To summarize all of the foregoing, contrary to Exxon's assertion, Exxon I does not conclusively establish that the relevant market area in 1975 was the Texas Gulf Coast/East Texas region, consisting of Texas Railroad Commission Districts 2 through 6, inclusive. We reach this conclusion for two reasons. First, and most importantly, the relevant market area that Exxon proposes in the case at bar, *supra*, is not identical to the relevant market area expressly adopted in Exxon I, 33 Fed. Cl. at 259, 262, *i.e.*, Railroad Commission Districts 2, 3, 4, and 6, but not District 5. Second, the record clearly demonstrates a plenitude of factual differences, as between 1974 and 1975, that were potentially "material, i.e., having legal significance." Arkla, 37 F.3d at 625. Therefore, we hold that the doctrine of collateral estoppel is inapplicable to the determination of the relevant market area in 1975. Having so held, the court now turns to the merits of Exxon's case regarding the issue of the relevant market area in 1975.

2. *Determination Of The Relevant Market Area In 1975*

Certain fundamental principles, laid down in the Hugoton and Panhandle cases, guide our determination of whether Exxon has carried its burden of establishing the relevant market area in 1975, relative to the gas production from the 369 Exxon properties in issue. Basically, the question is whether the Texas Gulf Coast/East Texas region, consisting of Texas Railroad Commission Districts 2 through 6, inclusive, was geographically "representative of the taxpayer's production" in issue. Panhandle, 187 Ct. Cl. at 155; 408 F.2d at 706. In Hugoton I, the Court of Claims explicated generally the analytical approach to be used in determining the geographical outlines of the relevant market area, as follows:

The determination of [the RMFP] requires that: "there have been recent, substantial, and comparable sales of like gas to gasoline extracting plants, carbon black plants, and the like, from wells in the area whose *availability for marketing* is reasonably or substantially similar to that of the gas here involved. . . . [T]he test is what do . . . [purchasers] pay for gas similar in quantity, quality, and *availability to market*?"

Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (emphasis added) (quoting Phillips, 155 F.2d at 198-99). "Availability to market," from the viewpoint of a natural gas producer, hinges upon the physical proximity of the producer's gas properties "to prospective buyers' pipelines." Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 895.(54)

Putting the aforementioned "availability to market" principle in sharper focus, the Hugoton I court held that, on remand, the RMFP had to be "calculated as the average price, weighted by quantity, of comparable gas sold *in the locality*" in which the taxpayer produced the gas in issue. Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 (emphasis added). Subsequently, in Hugoton II, the Court of Claims reiterated that because the RMFP "should be based on sales similar in 'availability to market,'" the RMFP computation "call[s] for comparable sales in the [taxpayer's] 'locality.'" Hugoton II, 172 Ct. Cl. at 464, 349 F.2d at 430 (quoting Hugoton I, *supra*). Further, the court pointedly declared that "common sense dictates that when there are comparative sales within the [taxpayer's] immediate area practicalities should limit the [RMFP computation] to their use." Hugoton II, 172 Ct. Cl. at 464, 349 F.2d at 431. Stated differently, the relevant market area in an RMFP case should be, as nearly as possible, geographically coterminous with the area from which the taxpayer produced the natural gas in issue.

Hugoton II provides three reasons why, in an RMFP case, a narrowly-defined market area is generally to be preferred over an expansively defined market area. First, the immediate locality of the taxpayer's gas production is the area in which sales of comparable gas are most likely to be found, due to the similarity, if not identicalness, of the underlying gas reservoirs. Hugoton II, 172 Ct. Cl. at 464, 349 F.2d at 431. Second, limiting the relevant market area, where feasible, to the immediate locality is "conducive to an easier administration of" the RMFP computation. Id. at 464-65, 349 F.2d at 431. Third, conforming the relevant market area, as nearly as possible, to the immediate locality "tends to equalize the taxpayer to his surroundings, i.e., the physical area in which his *immediate* competitors find themselves." Id. at 465, 349 F.2d at 431 (emphasis added). This third rationale goes to the very heart of the RMFP method, for it is "in accord with the general theory of Cannelton which tells us that in each of the three basic percentage depletion Acts, Congress indicated that integrated producers should not receive preferred treatment," relative to their "'*similarly situated*'" nonintegrated competitors. Id. at 465, 349 F.2d at 431 (emphasis added) (citing Cannelton, 364 U.S. 76) (quoting Ames v. United States, 330 F.2d 770, 773 (9th Cir. 1964)).

Therefore, in evaluating the propriety of a proposed relevant market area, for purposes of an integrated producer's RMFP computation, the court must consider whether the integrated producer, had it sold its gas at the wellhead during the taxable year in question, would have faced competition from other "similarly situated" sellers of comparable natural gas within the area under consideration. See Hugoton II, 172 Ct. Cl. at 457, 460, 349 F.2d at 426, 428 (finding that if the integrated producer taxpayer had sold its gas at the wellhead, it would have been in competition with other producers of similar gas located in the immediate area of the taxpayer's gas production). If the foregoing question can be answered in the affirmative, with respect to the immediate locality of the taxpayer's gas production, then the court need look no further. Id. at 464, 349 F.2d at 431. Conversely, if no wellhead sales of comparable gas by potential competitors can be found within the taxpayer's immediate locality, the court may expand the geographical scope of its inquiry and consider wellhead sales of comparable gas made elsewhere, because the relevant market area "should be broad enough to include sales of gas comparable to plaintiff's production." Panhandle, 187 Ct. Cl. at 148, 408 F.2d at 703.(55)

Upon applying the foregoing principles to the case at bar, we conclude that Exxon has made out a *prima* *facie* case that the Texas Gulf Coast/East Texas region, consisting of Texas Railroad Commission Districts 2 through 6, inclusive, constituted a market area that was geographically "representative of [Exxon's] production" in 1975 from the 369 properties in issue. Panhandle, 187 Ct. Cl. at 155; 408 F.2d at 706. Our conclusion rests upon three findings. First, it is undisputed that all of the 369 Exxon properties in issue were located within Districts 2 through 6.[(56)]

Second, given our prior findings that numerous pipeline companies operated in the Texas Gulf Coast/East Texas region in 1975, and that such pipeline companies competed vigorously in bidding for new gas supplies in that region, gas produced throughout the Texas Gulf Coast/East Texas region plainly manifested a ready "availability to market." Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (citation omitted); Hugoton II, 172 Ct. Cl. at 464, 349 F.2d at 430. Thus, as with the market area adopted in the Panhandle case, the Texas Gulf Coast/East Texas region constituted a "common competitive-purchase area . . . interlaced with competing pipelines." Panhandle, 187 Ct. Cl. at 156, 408 F.2d at 707.[(57)]

Third, it is clear that, if Exxon had been free to sell the gas in issue at the wellhead in 1975, it would have faced competition from other similarly-situated gas producers in the Texas Gulf Coast/East Texas region. This was indisputably so because, as shown by several maps in evidence, natural gas was being produced by many thousands of gas wells scattered throughout that region in 1975. Further, such maps demonstrate the presence of potential competitors, *i.e.*, other gas producers, in reasonably close proximity to the 369 Exxon properties in issue.[(58)] Therefore, had Exxon been free to sell its gas at the wellhead in 1975, it no doubt would have faced competition from many "wells . . . whose availability for marketing [was] reasonably or substantially similar to" Exxon's gas. Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (quoting Phillips, 155 F.2d at 198).

On this record, we find that there was an active natural gas market in the Texas Gulf Coast/East Texas region in 1975, involving many competing gas producers and many competing gas purchasers.[(59)] Moreover, said market was geographically "representative of the taxpayer's production" in issue. Panhandle, 187 Ct. Cl. at 155; 408 F.2d at 706. Given the foregoing, the court need not look beyond the Texas Gulf Coast/East Texas region, in order to identify sales of comparable gas qualifying for inclusion in the RMFP computation, unless the Government affirmatively goes forward with the evidence, and demonstrates the necessity of broadening the geographic scope of our inquiry. Hugoton II, 172 Ct. Cl. at 464, 349 F.2d at 431.

Because the Government failed to present a statewide gas comparability study, as noted above, it failed to affirmatively prove that the entire State of Texas was the relevant market area in 1975, and that the Texas Gulf Coast/East Texas region was not. Nonetheless, we must consider whether there is any probative evidence in the record tending to rebut Exxon's showing that the relevant market area in 1975 was the Texas Gulf Coast/East Texas region. From the perspective of a gas producer in the Texas Gulf Coast/East Texas region in 1975, one circumstance might be taken to imply that a further extension of the relevant market area is warranted -- specifically, the fact that the Permian Basin in West Texas furnished about 15% of the total supply of gas available in the Texas Gulf Coast/East Texas region in 1975. Seizing upon this fact at trial, defendant strove to establish the existence of active competition between Permian Basin gas producers and producers in the Texas Gulf Coast/East Texas region. Yet, the Government failed to demonstrate the influence, if any, that the influx of Permian Basin gas exerted upon the natural gas market in the Texas Gulf Coast/East Texas region, in terms of pricing, competition, or otherwise.

We find Mr. Welp's market area study, submitted on the Government's behalf, *supra*, totally unpersuasive. In forming the conclusion that the relevant market area was the entire State of Texas in 1975, Mr. Welp relied primarily upon the existence of interconnected gas pipeline systems throughout the state. Because pipeline facilities were available to transport gas from any gas producing area in Texas to any other locality in Texas, Mr. Welp reasoned, there must have been a statewide market for natural gas in 1975. However, Mr. Welp's market area study suffers numerous infirmities, all of which relate to the fact that his opinions regarding the relevant market area consist exclusively of speculation about what "could" have happened in the Texas natural gas industry in 1975, in plain contradistinction to what, in fact, *did* happen.[(60)]

Putative support for Mr. Welp's conclusion, *supra*, is furnished by a tabulation, contained in his report (DX 7, SubX E), that purports to show the extent to which gas pipelines could make interconnections between gas producing areas located in different Texas Railroad Commission Districts, throughout the entire State of Texas. Yet, Mr. Welp's tabulation of inter-district pipeline interconnections fails to address the volume of gas, if any, that was actually transported through such interconnections. Consequently, even if said tabulation is assumed to be a complete and accurate compilation of the inter-district pipeline interconnections existing within the State of Texas in 1975,[(61)] the court is unable to evaluate whether gas flowed through such interconnections in volumes that might materially influence the determination of the relevant market area for purposes of computing the RMFP. Moreover, Mr. Welp failed to demonstrate how such gas transportation and exchange transactions relate, if at all, to the segment of the Texas natural gas industry that is pertinent to the RMFP computation -- sales of gas at the wellhead.[(62)]

More importantly, Mr. Welp's exclusive focus upon the mere existence of interconnected pipeline systems throughout the State of Texas utterly ignores the direction of the gas flow within such pipelines. This omission is reflected in his stated opinion that any gas producer located in the Texas Gulf Coast/East Texas region in 1975, including Exxon, could market its gas to customers located in the western two-thirds of Texas. If true, Mr. Welp's view would suggest that gas producers in the Texas Gulf Coast/East Texas region were the immediate competitors of gas producers in West Texas, *i.e*., the Permian Basin. However, Mr. Welp presented not *one* concrete example of a 1975 transaction in which gas produced in the Texas Gulf Coast/East Texas region was transported *westward* for consumption in West Texas.

We doubt that evidence of any such transaction exists. In 1975, the pipelines connecting West Texas with the Texas Gulf Coast were flowing gas from west to east, not east to west. West Texas contained no major metropolitan areas or industrial centers comparable to those located along the Texas Gulf Coast in the general vicinity of Houston. Therefore, as Mr. Ellis aptly put it at trial, the pipelines connecting West Texas with the Texas Gulf Coast were "not created to take gas from the Gulf Coast out into empty West Texas." Tr. 916. As a consequence, West Texas pipeline companies did not bid to purchase gas in the Texas Gulf Coast/East Texas region, for westward transportation to, and eventual resale in, the West Texas marketplace. Further, given the immediate proximity of a major gas consumption market in the Texas Gulf Coast/East Texas region, gas producers in that region had no rational motive to seek to market their gas in West Texas in 1975. Thus, in terms of supplying gas to the West Texas marketplace, the notion that Texas Gulf Coast/East Texas gas producers stood in the posture of immediate competitors to Permian Basin gas producers, as Mr. Welp sought to imply, is patently fallacious.

Of course, there remains the fact that a significant volume of Permian Basin gas did flow eastward in 1975, furnishing about 15% of the total supply of gas available in the Texas Gulf Coast/East Texas region. From that circumstance, one might reasonably infer that Permian Basin gas producers were competing, to some degree, with the indigenous gas producers of the Texas Gulf Coast/East Texas marketplace. That inference, albeit plausible, does not warrant an expansion of the relevant market area, however, because nothing in the record suggests that the aforementioned influx of Permian Basin gas exerted a material influence upon the market price of natural gas in the Texas Gulf Coast/East Texas region in 1975. Indeed, there is substantial evidence to the contrary, in the form of the price redetermination clauses that saw prevalent usage in gas purchase contracts throughout the Texas Gulf Coast/East Texas region in 1975, *supra*. In his written report, Mr. Buie describes the geographical area typically addressed by such price redetermination clauses, as follows:

[W]hile price redetermination provisions in the early 1970s had referred to prices in a particular Railroad Commission District, by 1974 and 1975 these clauses were broadened to let the redetermined price be the average of the two or three highest prices being paid in several Railroad Commission Districts. Even as early as July 1974, HPL's contract with Hughes & Hughes for [the purchase of gas] production from the McKinney lease provided for a semiannual price redetermination to the average of the two highest prices in Railroad Commission Districts 2, 3, and 4. [PX 14a at H0071793.] By 1980, some contracts required redetermination based on the highest price being paid in the entire state of Texas, *though that was not the case in 1975*.

PX 2 at 12 (emphasis added) (footnote omitted).

The foregoing statement is uncontroverted and, further, conforms substantially to the findings made in Exxon I as to the usage and scope of price redetermination clauses in 1974, including the fact that statewide price redeterminations did not come into use until 1980. See Exxon I, 33 Fed. Cl. at 261-62. Moreover, upon examining a substantial number of the pipeline company contract files in the record, this court finds that Mr. Buie's statement accurately describes the typical geographic scope of such price redetermination clauses in 1975. All of the aforesaid contract files relate to gas produced and sold in the Texas Gulf Coast/East Texas region, consisting of Railroad Commission Districts 2 through 6, inclusive. We noted no statewide price redetermination clauses in effect as of 1975, nor any price redetermination clauses that embraced Railroad Commission Districts 7C and 8, wherein the Permian Basin is situated. (63)

This finding, we think, conclusively disposes of any suggestion that for purposes of computing the RMFP, with respect to Exxon's 1975 gas production from the 369 properties in issue, the relevant market area should include the Permian Basin. It is firmly settled that in an RMFP case, the relevant market area should be reflective of "the physical area in which [the taxpayer's] *immediate* competitors find themselves." Hugoton II, 172 Ct. Cl. at 465, 349 F.2d at 431 (emphasis added). Plainly, inasmuch as price redeterminations in the Texas Gulf Coast/East Texas marketplace were customarily made without reference to the price of gas in the Permian Basin in 1975, gas producers in said marketplace did *not* perceive Permian Basin gas producers to be their *immediate* competitors. For this reason, it cannot be plausibly maintained, on this record, that Permian Basin gas prices were *representative* of the price that Exxon could have obtained in 1975, had it sold the gas in issue at the wellhead, in the Texas Gulf Coast/East Texas marketplace. We conclude, therefore, that the inclusion of the Permian Basin in the relevant market area, here at bar, would violate "the fundamental goal of the [RMFP] calculation," which "is to arrive at a price that is *representative* of the price which would be realized by nonintegrated producers" situated similarly to Exxon. Exxon I, 88 F.3d at 976 (emphasis in original). See also Hugoton II, 172 Ct. Cl. at 465, 349 F.2d at 431 (noting focus of relevant market area determination upon "similarly situated" nonintegrated competitors).

In sum, given all of the foregoing, the court holds that Exxon has carried its burden of proving, by a preponderance of the evidence, that the Texas Gulf Coast/East Texas region, consisting of Texas Railroad Commission Districts 2 through 6, inclusive, constituted a market area that was geographically "representative of [Exxon's] production" in 1975 from the 369 properties in issue. Panhandle, 187 Ct. Cl. at 155, 408 F.2d at 706. Of course, whether the Texas Gulf Coast/East Texas region was the *relevant* market area, for purposes of computing the RMFP, ultimately depends upon whether Exxon has established that its 1975 gas production from the 369 properties in issue was comparable to gas produced and sold generally throughout that region. Id. Accordingly, we now turn to the issue of gas comparability.

II. *Comparability Of Gas*

A. *Background*

With respect to the issue of gas comparability, Exxon's burden is to establish that the gas represented in the 2,058 transactions in Mr. Ellis' RMFP study (hereinafter the "Ellis gas") was "'reasonably or substantially similar,'" to Exxon's 1975 gas production from the 369 properties in issue (hereinafter the "Exxon gas"). Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (quoting Phillips, 155 F.2d at 198). Exxon can also discharge its burden by showing that its gas was *superior* to the Ellis gas.(64) Panhandle, 187 Ct. Cl. at 156, 408 F.2d at 707 (holding that the taxpayer had met its burden of proving comparability because its gas was, "if anything, . . . *more valuable* than the [gas] production throughout its selected [market] area" (emphasis added)); Exxon I, 33 Fed. Cl. at 270 ("The evidence supports a finding that the gas in issue here was comparable or *superior* to the gas sold in the market area applicable in this case." (emphasis added)).

Six factors are given weight in making the gas comparability determination: (i) the volume of gas available for sale; (ii) the delivery or rock pressure of the gas; (iii) the deliverability of the producer's wells; (iv) the location and proximity of the producer's lease(s) to gas pipelines; (v) the hydrogen sulfide content of the gas; and (vi) the Btu content, or heating value, of the gas. Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 894-95; Hugoton II, 172 Ct. Cl. at 449-50, 349 F.2d at 420-21; Panhandle, 187 Ct. Cl. at 156, 219, 408 F.2d at 707; Exxon I, 33 Fed. Cl. at 270. Of the six factors listed above, the first four relate to the quantity, location, and availability of the gas, whereas the latter two relate to the chemical composition of the gas. The relevance of such gas comparability factors, in connection with the RMFP computation, lies in the degree to which they influence the price of the natural gas under consideration. Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 872.

B. *Contentions Of The Parties*

Exxon primarily relies upon the trial court's holding in Exxon I that, with respect to the year 1974, "the [Exxon] gas in issue here was comparable or superior to the gas sold in the market area applicable in this case." Exxon I, 33 Fed. Cl. at 270. Given the foregoing, Exxon maintains that the doctrine of collateral estoppel bars the relitigation of the gas comparability issue, here at bar, relative to the year 1975, because there were no material factual differences, as between the years 1974 and 1975, that might alter the gas comparability determination. In this regard, Fred Watson, a natural gas accountant employed by Exxon since 1973, testified that "[b]y far, the majority of the gas that was produced in 1975 was produced from the same properties that were at issue in 1974." Tr. 1380. Regarding the fact that 482 Exxon gas properties were in issue in Exxon I, 33 Fed. Cl. at 259, but only 369 Exxon properties are in issue here, relative to 1975, Mr. Watson explained that most of that difference relates to Exxon's "unitization" of over 150 properties in the Hawkins Field in East Texas, effective January 1, 1975, meaning that the 150 unitized properties were thereafter accounted for as a single combined property.(65) As to the occurrence of any other changes in the identity of the Exxon gas properties in dispute, as between 1974 and 1975, Mr. Watson testified that although there were "other miscellaneous adds and deletes, . . . the big properties such as the King Ranch leases, Katy and Pledger all were still the same between the two years." Tr. 1381. Exxon contends, further, that the Ellis gas, here at bar, manifested no significant physical differences from the gas represented in the 2,228 transactions in the 1974 RMFP study that Mr. Ellis submitted in Exxon I. In addition, Mr. Pohler testified that his 1975 gas comparability study (PX 1), *supra*, utilizes the same methodology as the 1974 gas comparability study that he submitted in Exxon I.

Moreover, irrespective of its collateral estoppel argument, Exxon also maintains that it met its burden of proving that its 1975 gas production in issue was comparable or superior to the Ellis gas. Specifically, upon considering all six of the relevant gas comparability factors, *supra*, pursuant to his gas comparability study, Mr. Pohler opined that Exxon's gas was "of higher quality, on average," than the Ellis gas. PX 1 at 44. Consistent therewith, based upon his personal experience as a gas buyer for Houston Pipe Line Company in the mid-1970s, Mr. Buie opined that if the Exxon gas in issue had been available for sale at the wellheads in 1975, "it would have set a new threshold price to be paid for natural gas." Similarly, Mr. Eakin opined that Exxon's gas could have commanded a wellhead price higher than any wellhead price being paid in the Texas Gulf Coast/East Texas region in 1975. In addition, Mr. Hague opined that if Exxon had made wellhead sales of the gas in issue into the interstate market, such gas would have brought the very maximum price allowable under the FPC's price control regulations.

In response to the foregoing, the Government advances two basic arguments. First, the Government contends that Mr. Pohler's gas comparability study is fatally flawed, in that it addresses only the "gas well gas" in issue, but not the "casinghead gas" in issue. "Gas well gas" is gas that is found in a gaseous state at reservoir conditions, *i.e.*, while in its natural state underground. Gas produced from oil wells as a byproduct of crude oil production is referred to as "casinghead gas," because it is dissolved in crude oil at reservoir conditions, but becomes gaseous at the lesser atmospheric pressure encountered at the top, or "casinghead," of an oil well. Gas well gas differs from casinghead gas in several respects. Oil wells that produce casinghead gas generally produce such gas in smaller volumes, at lower pressure, and at lower rates of delivery, than gas wells. Further, casinghead gas typically contains higher concentrations of the heavier liquefiable hydrocarbons (*i.e.*, ethane, propane, butane, etc.) than gas well gas. See Exxon I, 33 Fed. Cl. at 256 (findings to same effect, relative to 1974). As discussed in greater detail below, although Mr. Pohler's gas comparability study addresses the Btu content of the casinghead gas in issue, he admitted that his study fails to address the other five gas comparability factors, *supra*, insofar as they relate to such casinghead gas.[(66)]

Secondarily, on the Government's behalf, Mr. Martin submitted a report that purports to demonstrate that Mr. Pohler's methodology for comparing the Btu content of Exxon's gas and the Ellis gas is seriously defective. However, Mr. Martin's report and testimony focused *solely* upon Btu content, leaving Mr. Pohler's determinations as to the other five gas comparability factors, *supra*, essentially uncontroverted. [(67)] Having thus delineated the litigants' respective positions on the gas comparability issue, the discussion now turns to Exxon's collateral estoppel argument.

C. *Discussion*

1. *Collateral Estoppel*

As the proponent of collateral estoppel, Exxon has the initial burden of making out a *prima facie* case that the gas comparability determination in the case at bar, relative to 1975, involves issues of fact and law that are identical to the issues that were actually litigated and decided, pursuant to the gas comparability determination in Exxon I, relative to 1974. Arkla, F.2d at 624. See also McMullan, 231 Ct. Cl. at 382-84, 686 F.2d at 918-19 (determination that issues presented are the same is prerequisite to imposing burden of showing material factual differences upon party against whom collateral estoppel asserted). In deciding whether Exxon has met its burden, our inquiry necessarily begins with the trial court's opinion in Exxon I. [(68)] That opinion furnishes little enlightenment, however, for it simply enumerates the six gas comparability elements enunciated in the Hugoton and Panhandle cases, and then concludes, without any elaboration, that "[t]he evidence supports a finding that the [Exxon] gas in issue was comparable or superior to the gas sold in the market area applicable in" the taxable year 1974. Exxon I, 33 Fed. Cl. at 270 (citing Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 894-95; Hugoton II, 172 Ct. Cl. at 449-50, 349 F.2d at 420-21; Panhandle, 187 Ct. Cl. at 156, 219, 408 F.2d at 707). Thus, it can definitely be said that a factual finding of comparability was made in Exxon I, but from that terse finding, little can be inferred about whether the factual issues presented in the case at bar are identical to the factual issues actually litigated and decided in Exxon I.

Yet, in light of the record accumulated at trial, we are convinced that the gas comparability issues presently before this court are *not* the same as the gas comparability issues litigated and decided in Exxon I. First, we are plainly confronted with a number of gas properties that were not at issue in Exxon I. In explaining why the number of Exxon gas properties in issue fell from 482 in 1974, to 369 in 1975, Mr. Watson cited the Exxon's unitization of over 150 properties in the Hawkins Field in East Texas, effective January 1, 1975. Simple arithmetic instructs that if over 150 properties are aggregated into a single, unitized property, there will be at least 149 fewer properties after the unitization. Therefore, upon subtracting 149 properties from the 482 properties at issue in Exxon I, we find that as of January 1, 1975, immediately following the unitization, there existed not more than 333 Exxon gas properties that had any connection with Exxon I. Inasmuch as 369 Exxon properties are in issue with respect to the year 1975, it logically follows that at least 36 of those properties were not at issue in Exxon I.(69)

What is more, in 1974, the Exxon gas in issue was produced by approximately 5,000 wells, of which about 1,000 were gas wells producing gas well gas and roughly 4,000 were oil wells producing casinghead gas. Exxon I, 33 Fed. Cl. at 259. With respect to 1975, and in contrast to the foregoing, the Exxon gas in issue was produced by roughly 1,140 gas wells and 4,000 oil wells.(70) Although the approximate number of oil wells is seemingly unchanged, the court can scarcely overlook the fact that, between 1974 and 1975, the number of Exxon gas wells in issue increased by the net figure of 140 gas wells. We decline to merely *assume* that Exxon I's comparability finding extended to 140 Exxon gas wells that either did not exist in 1974, having not yet begun production, or were otherwise not at issue in Exxon I.

Moreover, we are constrained to note that Exxon has presented absolutely *no* credible evidence in support of its sweeping claim that the gas represented in the 2,058 transactions in Mr. Ellis' RMFP study, here at bar, is substantially the same as the gas that was represented in the 2,228 transactions in Mr. Ellis' 1974 RMFP study, submitted in Exxon I. Indeed, the very fact that Mr. Ellis' 1975 RMFP study contains 170 fewer transactions than his 1974 RMFP study implies quite the contrary. It was certainly within Exxon's ability to present evidence that would show whether the transactions in Mr. Ellis' 1974 and 1975 RMFP studies involved substantially similar gas. For example, at a minimum, Exxon could have presented the 1974 gas comparability study that Mr. Pohler submitted in Exxon I. In addition, Mr. Ellis no doubt could have prepared and submitted workpapers showing the extent to which the 2,058 transactions in his 1975 RMFP study correspond, in terms of the identity of the underlying gas properties, to the 2,228 transactions in his 1974 RMFP study. From Exxon's failure to present such evidence, the court infers that such evidence, if produced, would have been adverse to Exxon's position.(71)

Nor has Exxon alleged, much less shown, that the respective *wells* associated with Mr. Ellis' 1974 and 1975 RMFP studies were substantially identical. Although Mr. Platt submitted a study (PX 5) that identifies the wells associated with Mr. Ellis' 1975 RMFP study, the record contains no corresponding well identification study for the year 1974. Further, according to Mr. Platt's well identification study, the 2,058 transactions in Mr. Ellis' 1975 RMFP study involved hundreds of wells that first began production in 1975.(72) It cannot be rationally maintained that the comparability of the gas produced by such post-1974 wells, to Exxon's gas, was an issue that was actually litigated and decided in Exxon I, wherein the comparability finding was concerned exclusively with wells that were producing gas as of 1974. Similarly, lacking a 1974 well identification study, the court cannot rule out the possibility that some of the wells represented in Mr. Ellis' 1974 RMFP sample might have depleted and ceased production by 1975.

Given all of the foregoing factual differences, as between 1974 and 1975, we are unable to conclude that the gas comparability issue before this court is the same gas comparability issue that was litigated and decided in Exxon I. Such factual differences are not immaterial but, rather, relate to the issue of gas comparability, an indispensable element of the taxpayer's burden of proof in an RMFP case. See, e.g., Panhandle, 187 Ct. Cl. at 155; 408 F.2d at 706 (stating requirement that "comparable gas should be used"). Thus, the factual differences pertinent to the gas comparability issue, as between Exxon I and the case at bar, are indisputably "material, i.e., having legal significance." Arkla, 37 F.3d at 625. Consequently, we are constrained to hold that the doctrine of collateral estoppel does not preclude this court from making its own independent findings, here at bar, as to whether the 1975 Exxon gas production in issue was comparable to the gas represented in Mr. Ellis' RMFP study. Accordingly, we now turn to the merits of the gas comparability issue.

2. *Gas Comparability Determination*

At trial, it was Exxon's burden to demonstrate, by a preponderance of the evidence, that its 1975 gas production from the 369 properties in issue was "reasonably or substantially similar" to the Ellis gas, *i.e.*, the gas represented in the 2,058 transactions in Mr. Ellis' RMFP study. Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (internal quotation omitted). Here at the outset, we note two flaws in the gas comparability study that Mr. Pohler submitted on Exxon's behalf. First, in order to identify the wells that produced the Ellis gas during 1975, Mr. Pohler relied upon Mr. Platt's well identification study, which identifies 6,259 oil and gas wells that were associated with 1,810 of the transactions in Mr. Ellis' RMFP study. Although the court is satisfied with the accuracy of Mr. Platt's well identifications, in connection with those 1,810 transactions,(73) we are constrained to note that he failed to identify *any* wells that were associated with the other 248 transactions in Mr. Ellis' RMFP study. Without such well data, it is plainly impossible to ascertain whether the gas represented in those 248 transactions was comparable to Exxon's gas. Accordingly, the 248 transactions lacking well data must be excluded from consideration in the RMFP computation, and the remainder of the discussion below is addressed exclusively to the 1,810 transactions for which well data was available.

Second, we agree with the Government that Exxon failed to meet its burden of proving comparability with respect to any of the casinghead gas in issue. As noted above, Mr. Pohler admitted that his gas comparability study completely fails to address five of the six gas comparability factors, *supra* (Btu content being the exception), in connection with *any* of the casinghead gas in issue, whether produced by the 4,000 Exxon oil wells in issue, or by the oil wells associated with the 2,058 transactions in Mr. Ellis' RMFP study. By way of attempted justification for his failure to perform a complete comparability analysis in connection with the casinghead gas in issue, Mr. Pohler asserted that the availability of production data for oil wells that produce such gas is limited by the fact that oil wells are generally grouped together and reported by lease, not individually. Due to the foregoing, Mr. Pohler explained, "a direct comparison would have been very difficult." Tr. 169. Admitted difficulty, however, is an insufficient response for failure of proof, where such proof is not clearly shown to be unavailable. We are not convinced, therefore, that the purported unavailability of such production data was an insurmountable obstacle. On the contrary, it is evident that Mr. Pohler did, in fact, have access to additional information that would have allowed him to address, in somewhat greater detail, the comparability of the casinghead gas in dispute.(74)

To all appearances, Mr. Pohler's failure to perform a comprehensive comparability analysis, relative to the casinghead gas in issue, was the consequence of a tactical decision on Exxon's part to focus its litigation resources on gas well gas. Mr. Pohler repeatedly stressed the fact that over 90% of the Exxon gas in issue was gas well gas, and admitted, further: "So we concentrated our effort on the gas wells which produced the vast majority of the gas." Tr. 87. In terms of costs and potential benefits, Exxon's nearly singular focus on gas well gas, the bulk of the gas in issue, is understandable. However, that does not excuse Exxon's failure to even attempt to make a plausible showing of comparability with respect to the casinghead gas in issue. Having made the decision to address the comparability of its casinghead gas in cursory fashion, Exxon must bear the consequences of that decision.

Nor are we persuaded that Mr. Pohler's comparability determinations with respect to gas well gas, *infra*, can be validly extrapolated to the casinghead gas in issue. Mr. Pohler admitted that casinghead gas and gas well gas are generally not comparable, in that casinghead gas is usually produced in smaller volumes, at lower pressures, and at lower rates of delivery, than gas well gas, and typically has a higher Btu content as well.[(75)] See Exxon I, 33 Fed. Cl. at 256 (findings to same effect, relative to 1974). If Mr. Pohler's comparability determinations for the gas well gas in issue were extrapolated to Exxon's casinghead gas, that would, in essence, merely aggregate Exxon's casinghead gas with its *dissimilar* gas well gas. To the untutored eye, this approach might obscure Exxon's failure of proof regarding the comparability of its casinghead gas. In fact, burying Exxon's casinghead gas within a much larger volume of dissimilar gas well gas accomplishes absolutely nothing in the way of proving that Exxon's casinghead gas was comparable to the gas represented in Mr. Ellis' RMFP study. Thus, on this record, the court finds that Exxon has failed to establish that its 1975 casinghead gas production from the roughly 4,000 Exxon oil wells in issue was comparable to any of the Ellis gas. Accordingly, given that finding, we hold that Exxon must exclude such casinghead gas, representing approximately 9.74% of the Exxon gas in issue, in terms of volume (Mcf),[(76)] from the computation of its 1975 percentage depletion allowance.

Notwithstanding the foregoing, the court finds that Exxon has met its burden of proving that its 1975 gas well gas production in issue was comparable or superior to the Ellis gas well gas. We reach this conclusion, in large part, because Mr. Pohler's determinations as to five of the six gas comparability factors, *supra*, are essentially uncontroverted, with Btu content being the only factor truly in dispute. In light of the evidence accumulated at trial, we address each of the six gas comparability factors below, *seriatim*.

a. *Volume Available for Sale*

The volume of gas available for sale relates to the total size of the proven, prospectively recoverable, reserves contained within a particular underground reservoir of natural gas. "Generally, the greater the volume or reserves, the greater the price the seller [can] command." Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 894; Hugoton II, 172 Ct. Cl. at 449-50 n.7, 349 F.2d at 420 n.7; Panhandle, 187 Ct. Cl. at 219. See also Exxon I, 33 Fed. Cl. at 261 (finding to similar effect). A larger reserve commands a higher price, because pipeline companies are more willing to make the investment in constructing a pipeline and appurtenant facilities in order to take delivery of the gas. Stated differently, a larger supply of gas allows the pipeline company to spread, or amortize, the cost of the requisite pipeline facilities over more units of purchased gas, thereby lowering the per-unit cost of the gas.

In order to compare the total volume of gas available for sale in 1975, with respect to the 369 Exxon gas properties in issue and the gas properties relating to the 2,058 transactions in Mr. Ellis' RMFP study (the Ellis properties), Mr. Pohler had to estimate the total gas reserves underlying such gas properties as of 1975. Using production data obtained from a commercial database of oil and gas well statistics maintained by the firm of Petroleum Information/Dwights LLC (hereinafter, the "Dwights database"), Mr. Pohler calculated the total volume of gas produced by the gas wells in issue during the 23-year period from 1975 through 1997.[(77)] From the cumulative production volume during the 1975-1997 period, Mr. Pohler deduced the total volume of gas reserves beneath each gas well in issue, as of the beginning of

1975. Having so ascertained the estimated reserves underlying the Exxon gas wells and the Ellis gas wells as of 1975, Mr. Pohler then aggregated the estimated reserves by reference to the fields in which those wells were located, in order to obtain an indication of the total volume of gas available for sale at each such field. Upon comparing the total estimated reserves underlying the largest 20 Exxon fields and the largest 20 Ellis fields, Mr. Pohler concluded that in 1975, the reserves underlying the Exxon fields were, on the average, considerably larger than the reserves underlying the Ellis fields. On this record, given defendant's lack of opposition to Mr. Pohler's determinations, we find that Exxon's gas well gas was superior to the Ellis gas well gas, in terms of the respective volumes of gas that were available for sale in 1975.

b. *Delivery or Rock Pressure*

Natural gas, when confined in an underground reservoir in its original state, exists under conditions of pressure. Generally, such pressure is a function of the depth of the reservoir, with greater pressure encountered at greater depths. This natural pressure causes gas to flow upward through the well bore to the surface of the earth because, under the laws of nature, gas flows from a high pressure area into a lower pressure area. Panhandle, 187 Ct. Cl. at 224-25. In order for natural gas to flow freely from the producer's well into the buyer's pipeline, without mechanical assistance, the well must produce gas at a pressure that exceeds the operating pressure of the pipeline. Conversely, when the pipeline pressure exceeds the natural pressure at which the well can produce gas, the natural pressure of the gas must be increased, by means of mechanical compression, in order to transport the gas into the purchaser's pipeline. See Exxon I, 33 Fed. Cl. at 256 ("A well's pressure is an indicator of its ability to flow gas to a pipeline.").

Although alternate measures of pressure exist, the "flowing tubing pressure" (FTP) is the most representative measure of a well's ability to deliver natural gas into a buyer's pipeline, inasmuch as it is measured at the wellhead, while the well is actually producing gas, and incorporates pressure losses due to friction in the well bore and reservoir.(78) "Generally, the higher the pressure [of the well], the less compression for transportation is required." Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 895; Hugoton II, 172 Ct. Cl. at 449-50 n.7, 349 F.2d at 420-21 n.7; Panhandle, 187 Ct. Cl. at 219; see also id. at 222-23. Thus, inasmuch as it is costly to install, operate, and maintain compression facilities, gas produced by a high-pressure well is generally more valuable than gas produced by a low-pressure well.

For purposes of comparing the delivery pressures of the Exxon gas wells in issue, with the gas wells associated with the 2,058 transactions in Mr. Ellis' RMFP study, Mr. Pohler obtained FTP measurements for such wells from the Dwights database. Upon calculating the volume-weighted average FTP of each group of gas wells in issue, Mr. Pohler determined that Exxon's gas wells had an average FTP of 970 psig, whereas the Ellis gas wells had an average FTP of 750 psig.(79) At trial, the foregoing determinations were unchallenged by the Government and its experts. Therefore, on this record, the court finds that the Exxon gas well gas in issue was superior to the gas well gas represented in Mr. Ellis's RMFP study, because Exxon's gas wells had, on the average, a higher delivery pressure in 1975 than the Ellis gas wells.

c. *Deliverability of Producer's Wells*

Deliverability is another measure of a well's ability to flow gas, and is typically stated as an average daily rate of production, *i.e.*, the average volume of gas produced within a 24-hour period (Mcf/day, MMcf/day, etc.).[(80)] Generally, "the larger the volume [of gas] that [can] be delivered from a reserve, the greater the price the seller [can] command." Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 895; Hugoton II, 172 Ct. Cl. at 449-50 n.7, 349 F.2d at 420-21 n.7; Panhandle, 187 Ct. Cl. at 219. See also Exxon I, 33 Fed. Cl. at 261 (finding to same effect, relative to 1974).[(81)] Based upon the 1975 annual production volumes of the gas wells in issue, obtained from the Dwights database, Mr. Pohler determined that the daily average volume produced by Exxon's gas wells was approximately 2.33 MMcf per day in 1975, whereas the Ellis gas wells averaged only about 0.47 MMcf per day. On the basis of the aforesaid uncontested evidence, the court finds that Exxon's gas well gas was substantially superior, in terms of its 1975 rate of deliverability, to the Ellis gas well gas in issue.

d. *Location and Proximity of Producer's Lease(s) to Gas Pipelines*

Due to the cost of laying pipelines to transport gas from the producer's well to the purchaser's pipeline, a relevant consideration in the valuation of natural gas is the "location of the [producer's] leases or acreage involved, whether in a solid block or scattered, and their proximity to prospective buyers' pipelines." Hugoton I, 161 Ct. Cl. at 320-21, 315 F.2d at 894; Hugoton II, 172 Ct. Cl. at 449-50 n. 7, 349 F.2d at 420-21 n.7. A meaningful comprehension of the foregoing requires an understanding of certain pipeline industry nomenclature. In the context of sales of gas by producers to pipeline companies, the "point of delivery," or delivery point, is the location constituting the physical point of sale, at which title to the gas passes from seller to buyer. At the point of delivery, a "custody meter" measures the volume of gas sold and delivered to the pipeline company. All pipeline company gas purchase contracts designate, in varying degrees of specificity, the point or points of delivery.

Pipelines of various sizes and capacities are used to transport gas from the well to the point of delivery and, thence, to end users. At trial, it soon became clear that different persons in the natural gas industry may use different terms to describe the same type of pipeline, or use the same term to refer to different types of pipeline. However, certain predominant usages and definitions emerged from the testimony of the parties' expert witnesses, and are adopted herein by the court, as follows. A "flow line" is a small-diameter pipeline, typically not more than two to three inches in diameter, that transports the full wellstream from the well to a nearby field separator, where liquid water and liquid hydrocarbons (condensates) are removed from the raw natural gas.[(82)] See Exxon I, 33 Fed. Cl. at 257 (similar definition of flow line).

A "gathering line" is a small-diameter pipeline that transports gas away from the separator to a central delivery point in the field, or to centrally-located facilities such as a dehydrator, compressor, or gas processing plant.[(83)] A "gathering system" is a network of gathering lines that transport gas away from multiple wells, or the appurtenant separators, to such central delivery points or facilities.[(84)] The foregoing definitions are supported by the preponderance of the relevant testimony at trial.[(85)] In addition, the pipeline company contract files in the record (PX 14a and PX 14b) routinely use the term "gathering" to refer to an arrangement whereby gas is transported from multiple wells to a central point.[(86)] Moreover, our conclusion as to the meaning of "gathering" is consistent with findings made in other RMFP cases. See Hugoton I, 161 Ct. Cl. at 297, 315 F.2d at 881 (describing producer's "gathering system" of pipelines that "gathered" gas from multiple wells to a central point for dehydration prior to delivery of the gas to the buyer); Panhandle, 187 Ct. Cl. at 162, 408 F.2d at 710-11 (noting that producer was "gathering" the gas from 13 wells to a common delivery point), 187 Ct. Cl. at 167, 408 F.2d at 713 (reference to such "gathering lines"), 187 Ct. Cl. at 173-74, 408 F.2d at 717-18 (twice referring to producer "gathering" gas from its multiple wells before sale); Exxon I, 33 Fed. Cl. at 257 (gathering to processing plant); Shamrock, 35 T.C. at 989 (same).

Small-diameter gathering lines of the sort described above typically converge into medium-diameter gathering lines, sometimes termed "laterals," which branch off from "transmission lines." Transmission lines are large-diameter pipelines, normally ranging between 12 and 36 inches in diameter, that transport large volumes of gas from gas producing areas, *i.e.*, gas fields, basins, or embayments, to areas populated by residential and industrial gas consumers.[(87)] See Exxon I, 33 Fed. Cl. at 258 (transmission line similarly defined); Shamrock, 35 T.C. at 989 (same). Such transmission lines are often hundreds of miles in length.[(88)]

On this record, to summarize the foregoing, the court concludes that any pipeline which transports gas from a wellhead to a field separator is a flow line. Any pipeline, including one of a series of successive pipelines, that transports gas from the outlet of a separator to a transmission line is a gathering line.[(89)] A gathering line, or a gathering system, may be constructed by the producer of the gas, by the pipeline company that purchases the gas, or by each in part. When a gas purchase contract is negotiated, it is the contractual specification of the delivery point which allocates the obligation to construct any necessary gathering lines between the producer and the pipeline company. In other words, upon negotiating a gas purchase contract, the producer and the pipeline company know where the producer's gas properties are, and where the pipeline company's nearest transmission line is. If it is agreed that the delivery point shall be at each of the producer's wellheads, then the pipeline company must build the gathering system in order to bring the gas to its transmission line. Conversely, if it is agreed that the delivery point shall be at the pipeline company's transmission line, then the producer must build the gathering system in order to deliver the gas.[(90)] Ofttimes the delivery point is located somewhere in between, as when a producer with multiple wells is contractually obligated to compress or dehydrate its gas prior to delivery. Such compression or dehydration is frequently done at central points in the field, rather than at each well, so that the producer can combine the gas streams from multiple wells, in order to achieve the cost savings that result from economies of scale.[(91)] Thus, the point of delivery may be situated anywhere between the outlet of the producer's separator and a point on the pipeline company's nearest transmission line, with the producer doing the gathering required, if any, to move the gas from its wells to the delivery point, and the pipeline company doing the gathering required, if any, to move the gas from the delivery point to its transmission line. As shall be seen, in a subsequent section of this opinion, delivery points were the subject of protracted controversy at trial, relative to the qualification of Exxon's 2,058 transactions for inclusion in the RMFP computation.

Irrespective of whether the delivery point is located at the wellhead, at the buyer's nearest transmission line, or somewhere in between, it is incontestable that the process of gathering gas entails the costs of installing, operating, and maintaining a gathering system. Such costs are lessened if the producer's gas properties are "well-blocked and compactly situated," rather than widely scattered, such that the delivery points are "better than average from the standpoint of costs of connection." Hugoton I, 161 Ct. Cl. at 320-21, 315 F.2d at 895; Hugoton II, 172 Ct. Cl. at 450, 349 F.2d at 421. Stated differently, gas is generally more valuable if the producer's "acreage [is] in convenient blocks from the standpoint of gathering costs and delivery" to the purchaser. Panhandle, 187 Ct. Cl. at 156, 223, 408 F.2d at 707. Similarly, gas is generally more valuable if the producer's acreage lies in close "proximity to prospective buyers' pipelines." Hugoton I, 161 Ct. Cl. at 320-21, 315 F.2d at 894; Hugoton II, 172 Ct. Cl. at 449-50 n. 7, 349 F.2d at 420-21 n.7. Given the natural gas shortage in 1975, the proximity of prospective buyers' pipelines was a particularly strong determinant of value, because the presence of two or more pipelines operating in the general vicinity of a newly-developed gas property would set off an energetic bidding war over the producer's gas.[(92)]

In order to compare Exxon's 369 gas properties with the Ellis gas properties, from the standpoint of their respective locations and proximity to prospective gas buyers' pipelines in 1975, Mr. Pohler had the firm of Petroleum Information/Dwights LLC (*i.e*., the proprietor of the Dwights database, *supra*) plot all of the gas wells in issue upon a map of the Texas Gulf Coast/East Texas region. Based upon his visual examination of that map, Mr. Pohler opined that Exxon's gas properties were as favorably located, with respect to the pipeline systems operating in the Texas Gulf Coast/East Texas region, as the Ellis gas properties.(93) However, in response to the court's inquiry, Mr. Pohler was unable to articulate the standard of distance on which he based that opinion, and ultimately admitted that his opinion rested upon no specific measurement standard.(94) Thus, Mr. Pohler's pipeline-proximity study amounted to an exercise in self-serving, subjective "eyeballing." "Eyeballing may have the advantage of ease, but it surely lacks scientific reliability in the sense of producing consistent results." Ayers v. Robinson, 887 F. Supp. 1048, 1060 (N.D. Ill. 1995) (rejecting "eyeballing" analysis of expert witness). See also Kurncz v. Honda North America, Inc., 166 F.R.D. 386, 389 (W.D. Mich. 1996); Pomella v. Regency Coach Lines, Ltd., 899 F. Supp. 335, 343 (E.D. Mich. 1995). The fundamental problem with Mr. Pohler's approach is that "[a]nyone can look at the same" map "and come up with a different" opinion. Ayers, 887 F. Supp. at 1060.

Moreover, Mr. Pohler's pipeline-proximity study failed to consider whether the leases or acreage associated with Exxon's 369 gas properties and the Ellis gas properties were located "in a solid block or scattered." Hugoton I, 161 Ct. Cl. at 320-21, 315 F.2d at 894; Hugoton II, 172 Ct. Cl. at 449-50 n. 7, 349 F.2d at 420-21 n.7. As noted above, this factor, or sub-factor, enters into the gas comparability determination because the internal geographical configuration of the producer's leases or acreage is a determinant of the size and cost of the gathering system that must be built in order to effectuate the delivery of the gas to the buyer's pipeline. Hugoton I, 161 Ct. Cl. at 320-21, 315 F.2d at 895; Hugoton II, 172 Ct. Cl. at 450, 349 F.2d at 421; Panhandle, 187 Ct. Cl. at 156, 223, 408 F.2d at 707. We certainly perceive no rational justification for Exxon's failure to address the internal geographical configuration of its own gas properties. Further, given the availability of the gas purchase contracts pertinent to most of the Ellis transactions, it was undeniably feasible for Mr. Pohler to have considered the internal geographical configuration of the leases or acreage associated with many of the Ellis gas properties.(95)

Despite the aforementioned shortcomings in Mr. Pohler's analysis, the various maps in the record clearly demonstrate the great number and density of the pipeline systems operating in 1975 throughout the Texas Gulf Coast area, *i.e*., "Pipeline Alley," and, to a lesser yet nonetheless substantial extent, in the East Texas area. None of Exxon's 369 gas properties or the Ellis gas properties was situated more than roughly ten miles from a pipeline, and the vast majority of such gas properties was located only one to two miles from one or more pipelines. Thus, it is evident to the naked eye that gas producers throughout the Texas Gulf Coast/East Texas region enjoyed convenient access to nearby pipelines.(96) Consequently, although we are unable, on this record, to make any general statement regarding the internal geographical configurations of the gas properties in issue,(97) the court nevertheless finds that Exxon's gas properties were reasonably comparable, on the average, to the Ellis gas properties, in terms of their proximity to pipelines operating in the Texas Gulf Coast/East Texas region in 1975.

e. *Hydrogen Sulfide Content*

Hydrogen sulfide is a poisonous gas that sometimes contaminates raw natural gas. Gas containing excessive amounts of hydrogen sulfide is termed "sour gas," whereas gas containing acceptable amounts of hydrogen sulfide is termed "sweet gas." See Panhandle, 187 Ct. Cl. at 156, 223, 408 F.2d at 707; Exxon I, 33 Fed. Cl. at 256-57. Sour gas makes poor fuel, because hydrogen sulfide is extremely toxic, highly corrosive in the presence of water, and, when burnt, emits a rotten-egg odor. Shamrock, 35 T.C. at

988, 1016. Thus, in gas purchase contracts, pipeline companies typically specify a maximum hydrogen sulfide content of one-quarter grain per hundred cubic feet of gas, which equates to about four parts per million. Sour gas can be "sweetened" by various chemical treatments in order to reduce its hydrogen sulfide content to tolerable levels. Due to the cost of treating sour gas to make it usable as fuel, sweet gas tends to command a commensurately higher price.

Based upon his personal experience as the gas supply coordinator of the Exxon Gas System from 1973 to 1986, Mr. Pohler testified that only about 0.2% of the Exxon gas in issue was sour gas, *i.e.*, gas containing more than the maximum one-quarter grain of hydrogen sulfide per 100 cubic feet that was permitted by pipeline gas quality specifications.[(98)] In contrast, based upon hydrogen sulfide content data obtained from the Dwights database, Mr. Pohler determined that at least 3% of the Ellis gas, in volumetric terms (Mcf), was sour gas. Therefore, with regard to hydrogen sulfide content, Mr. Pohler concluded that the Exxon gas in issue was of higher quality, on the average, than the Ellis gas in issue. Inasmuch as Mr. Pohler's determinations are uncontroverted, the court agrees. The mere fact that a very small proportion of the gas in issue was sour gas does not bar a finding of comparability. See Panhandle, 187 Ct. Cl. at 156, 408 F.2d at 707 (finding "[s]ome very small accumulations of sour gas" in the relevant market area, yet concluding that comparability had been sufficiently demonstrated). Accordingly, we find that the Exxon gas well gas in issue was of higher quality than the Ellis gas well gas in issue, in terms of hydrogen sulfide content.

f. *Btu Content*

In the natural gas industry, the heating value of gas is measured in terms of Btu content. Hugoton I, 161 Ct. Cl. at 293, 315 F.2d at 879; Panhandle, 187 Ct. Cl. at 156, 222-23, 408 F.2d at 707.[(99)] The Btu content of natural gas depends upon its chemical constituency. As noted above, the principal component of natural gas is methane, the lightest gaseous hydrocarbon. Raw natural gas produced in the Texas Gulf Coast/East Texas region is, on the average, approximately 90% methane, with the remaining 10% being constituted of the heavier, liquefiable hydrocarbon components, *i.e.*, "natural gas liquids" such as ethane, propane, butane, pentane, etc., and contaminants such as oxygen, nitrogen, carbon dioxide, and hydrogen sulfide. Not all raw gas is average in terms of Btu content, however. Rather, a distinction must be made between gas well gas, produced by gas wells, and casinghead gas, produced by oil wells. Casinghead gas ordinarily contains a lower proportion of methane and higher proportions of natural gas liquids.[(100)] See Exxon I, 33 Fed. Cl. at 256 (similar finding as to 1974). Therefore, inasmuch as natural gas liquids are richer fuels than methane, *i.e.*, possessing greater heating values, casinghead gas typically has a significantly higher Btu content than gas well gas.

Given two equal volumes of raw gas, produced from two different wells, the volume of gas with the higher Btu content tends to be the more valuable of the two. Panhandle, 187 Ct. Cl. at 156, 408 F.2d at 707; Exxon I, 33 Fed. Cl. at 258 ("Generally, the higher the Btu per Mcf at the well head, the more valuable the gas is . . . ."). The foregoing relationship between the heating value and the dollar value of a given *volume* of gas is most evident when gas is priced and sold *volumetrically*, *i.e.*, on a price-per-Mcf basis. By the early 1970s, however, the natural gas industry had largely moved away from the traditional volumetric method of pricing gas, in favor of "Btu pricing." Given that natural gas is predominantly bought and sold for its heating value, *i.e.*, as fuel to be burned, Btu pricing acknowledges that Btu content is a more accurate measure of value. Under Btu pricing, gas is typically priced and sold on a price-per-MMBtu (million Btu) basis, which tends to negate price disparities between high-Btu and low-Btu gas. The diminished significance of Btu content as a gas pricing criterion was noted in the litigation over Exxon's 1974 RMFP, as follows:

Another change in the industry was the shift in 1974, from Mcf-based to Btu-based pricing. This shift eliminated the distinction for pricing purposes, between processed and unprocessed gas. There were no premiums paid for high Btu content or for processed or unprocessed gas. *Gas was considered gas* and the only thing that mattered, other than reserve size and deliverability, was whether or not the gas met pipeline specifications.

Exxon I, 33 Fed. Cl. at 261 (emphasis added). Here at bar, the record establishes the continued predominance of Btu pricing in 1975. Further, as in 1974, gas prices under contracts with Btu pricing terms were not materially influenced by distinctions between high-Btu and low-Btu gas in 1975. As Mr. Eakin put it, under Btu pricing, "gas is gas and Btu is Btu." Tr. 619.[(101)]

However, notwithstanding the ascendancy of Btu pricing in the 1970s, the RMFP of natural gas has always been calculated and expressed in traditional *volumetric* terms, *i.e.*, as a price per Mcf. See Exxon I, 88 F.3d at 979; Panhandle, 187 Ct. Cl. at 160, 175, 408 F.2d at 709, 718. We see no compelling reason to depart from the foregoing convention, here at bar, inasmuch as the parties have prepared and submitted their respective RMFP computations in terms of volumetric pricing.[(102)] Therefore, because Btu content plainly influences the volumetric price of raw gas, it shall be treated as a relevant gas comparability factor herein.

For purposes of comparing the Btu content of the Exxon gas in issue with that of the Ellis gas, Mr. Pohler determined, on the basis of data extracted from Exxon's business records, that the volume-weighted average Btu content of Exxon's gas, at the wellhead, was approximately 1.080 MMBtu per Mcf. With respect to the Btu content of the Ellis gas, Mr. Pohler obtained 1975 Btu data for 1,092 of the 2,058 transactions in Mr. Ellis' RMFP study, from annual reports (Forms 2) filed by interstate pipeline companies with the FPC, and from documentation contained in the pipeline company contract files in PX 14a and PX 14b. As to the other 966 Ellis transactions, for which actual 1975 Btu data was unavailable, Mr. Pohler estimated the Btu content of the gas by using a statistical correlation, of his own creation, that purports to describe the relationship between the specific gravity of natural gas and its Btu content.[(103)] By way of illustration, ordinary air has a specific gravity of 1.0, whereas most gas well gas is lighter, or less dense, having a specific gravity ranging from 0.60 to 0.70. Casinghead gas, containing higher concentrations of the heavier liquefiable hydrocarbons, tends to have a higher specific gravity and Btu content than gas well gas. Thus, generally speaking, the specific gravity and Btu content of natural gas are positively correlated, meaning that as the specific gravity of gas increases, its Btu content likewise tends to increase, and vice versa.[(104)]

The underlying premise of Mr. Pohler's approach is that the Btu content of a particular volume of gas can be inferred by means of a generalized correlation between specific gravity and Btu content, if the specific gravity of such gas is known. In applying that methodology to each of the 966 Ellis transactions lacking actual 1975 Btu data, Mr. Pohler first obtained the pertinent 1975 specific gravity data from the Dwights database, then derived an estimate of the 1975 Btu content of the gas by applying his specific gravity/Btu correlation. Upon aggregating the foregoing estimated Btu values with the actual Btu values observed in connection with the 1,092 transactions for which actual 1975 Btu data was available, Mr. Pohler determined that the volume-weighted average Btu content of the gas represented in the 2,058 transactions in Mr. Ellis' RMFP study was 1.062 MMBtu per Mcf. Based upon his determination that Exxon's gas had a slightly higher average Btu content, in the amount of 1.080 MMBtu per Mcf, Mr. Pohler opined that on a volumetric basis (*i.e.*, price per Mcf), Exxon's gas was slightly more valuable than the Ellis gas in issue, in terms of Btu content.[(105)]

At trial, the Government and its gas comparability expert, Mr. Martin, raised no substantive objections to Mr. Pohler's determination of the average wellhead Btu content of the Exxon gas in issue, nor with respect to the 1,092 Ellis transactions for which Mr. Pohler obtained actual 1975 Btu data from the Dwights database. Rather, the Government focused its attack upon Mr. Pohler's usage of his specific gravity/Btu correlation, *supra*, to estimate the Btu content of the gas associated with the 966 Ellis transactions lacking 1975 Btu data. In Mr. Martin's view, Mr. Pohler's methodology is unacceptably imprecise, because a specific gravity/Btu correlation analysis fails to properly account for the fact that the presence of non-hydrocarbon gases in a raw gas wellstream, such as nitrogen, carbon dioxide, oxygen, or hydrogen sulfide, diminishes the Btu content of the gas. Consequently, Mr. Martin opined, "you can't determine with any reasonable certainty the Btu [content] from the gas [specific] gravity." Tr. 1925.

For at least two reasons, the court is not convinced by Mr. Martin's critique of Mr. Pohler's specific gravity/Btu correlation. First, Mr. Martin's contention that a specific gravity/Btu correlation cannot be used to estimate Btu content, when only the specific gravity of the gas is known, is at odds with the fact that natural gas engineering treatises prescribe such correlations. Confronted with two such published correlation tables, reproduced in Mr. Pohler's report, Mr. Martin conceded that there is, in fact, a direct correlation between specific gravity and Btu content.[(106)] Second, as Mr. Martin also admitted at trial, if Mr. Pohler errs in using his specific gravity/Btu correlation, he errs in the direction of *overstating* the Btu content of the Ellis gas -- in effect, making the Ellis gas appear to be of a higher quality than it actually is.[(107)] Given the foregoing, logic instructs that if Mr. Pohler's correlation tends to overstate the Btu content of the Ellis gas, it also tends to decrease the probability that Exxon will meet its burden of proving comparability, which requires a showing that its gas was comparable or superior to the Ellis gas. Panhandle, 187 Ct. Cl. at 156, 408 F.2d at 707; Exxon I, 33 Fed. Cl. at 270. Thus, rather than achieving his intended purpose of debunking Mr. Pohler's specific gravity/Btu correlation, Mr. Martin's critique actually suggests that Mr. Pohler's approach is inherently *conservative*, *i.e.*, tending to militate against Exxon's interests and toward the Government's favor.[(108)]

In addition, Mr. Martin objected to Mr. Pohler's usage of a correlation technique on the ground that a generalized specific gravity/Btu correlation may sometimes yield an imperfect estimate of Btu content in the case of an individual well. However, this contention overlooks the fact that a "sufficiently large and diverse" sample of transactions tends "to discount variations and offset errors" with respect to individual transactions. Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 704. See also Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877; Exxon I, 88 F.3d at 976, 977-78. Mr. Pohler developed his specific gravity/Btu correlation from a sample of 515 measurements of related specific gravity and Btu values, drawn from Exxon's HIS Segment 66 database, and applied that correlation to 966 Ellis transactions. We think such sample sizes have sufficient breadth to give assurance that, on the average, Mr. Pohler's correlation produces a reasonable approximation of the Btu content of the gas sold in those 966 Ellis transactions. Moreover, perfection has never been the standard for proving gas comparability in an RMFP case. See Hugoton II, 172 Ct. Cl. at 450 & n.9; 349 F.2d at 421 & n.9 (gas held comparable although its Btu content was merely "*in most cases* good") (emphasis added)).[(109)] Accordingly, on this record, we find that the Exxon gas well gas in issue was, on the average, comparable or slightly superior to the Ellis gas well gas in issue, in terms of Btu content.

3. *Gas Comparability -- Conclusion*

To summarize all of the foregoing, Exxon presented credible evidence demonstrating that its gas well gas, representing approximately 90.26% of the Exxon gas in issue, in volumetric terms (Mcf), was superior to the gas well gas represented in the 2,058 transactions in Mr. Ellis' RMFP study, in terms of: (i) the volume available for sale; (ii) delivery pressure; (iii) deliverability; and (iv) hydrogen sulfide content. Exxon also established that its gas well gas was comparable or slightly superior to the Ellis gas well gas, in terms of Btu content. Further, as to the location and proximity of the pertinent wells to prospective buyers' pipelines, Exxon showed that its 369 gas properties were comparable, on the average, to the Ellis gas properties.

With the exception of Btu content, as to which the Government failed to rebut Exxon's *prima facie* case of comparability, Exxon's proof with respect to each of the aforesaid gas comparability factors was unchallenged by the Government. For this reason, the Government failed to mount an effective attack upon the *overall* comparability of Exxon's gas and the Ellis gas. Indeed, the Government's gas comparability expert, Mr. Martin, testified that he had *no* opinion as to whether Exxon's gas and the Ellis gas were comparable, in overall terms, admitted that his report fails to address that question, and admitted, further, that he had no criteria of his own for determining gas comparability.(110) Asked how, given his own admitted lack of comparability standards, he could assert that Mr. Pohler's study fails to establish gas comparability, Mr. Martin weakly replied, "I'm not sure I can answer that." Tr. 1962. Moreover, as in the Hugoton case, "although the Government points to several differences" between Exxon's gas and the Ellis gas, "it presented no evidence that the differences were significant or *would have affected the price* which plaintiff could have obtained for its gas" if sold at the wellhead. Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 872 (emphasis added).

In short, the Government seeks to hold Exxon to a standard of gas comparability that is not only exacting, but effectively unattainable, inasmuch as the Government itself cannot articulate that standard. However, Exxon's burden is to prove merely that its gas was "reasonably or substantially similar" to gas produced generally throughout the Texas Gulf Coast/East Texas region, as represented by the gas sold in the 2,058 Ellis transactions. Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 871 (internal quotation omitted). On this record, we hold that Exxon has met that burden with respect to its gas well gas in issue, by showing that such gas was comparable or superior to the Ellis gas well gas. Moreover, given the foregoing, Exxon has shown that sales of gas comparable to its own gas well gas, *i.e.*, the Ellis gas well gas, occurred within the Texas Gulf Coast/East Texas region in 1975. Accordingly, for purposes of computing the RMFP applicable to the Exxon gas well gas in issue, the court holds that said region, consisting of Texas Railroad Commission Districts 2 through 6, inclusive, was the relevant market area in 1975.

Conversely, as discussed above, Exxon has failed to carry its burden of proving that its 1975 casinghead gas production, comprising approximately 9.74% of the Exxon gas in issue, in volumetric terms (Mcf), was comparable to any of the gas represented in Mr. Ellis' RMFP study. As a consequence, the court finds it impossible, on this record, to determine an RMFP with respect to Exxon's casinghead gas, as required under Treas. Reg. § 1.613-3(a). Therefore, we hold that such casinghead gas must be excluded from the computation of Exxon's 1975 percentage depletion allowance.(111) Having thus concluded our analysis of the gas comparability issue, the court now turns to consider whether any of the 2,058 transactions in Mr. Ellis' RMFP sample qualify for inclusion in the RMFP computation and, if so, how many.

III. *Identification Of Transactions Qualifying For Inclusion In The RMFP Sample*

As noted above, the RMFP of natural gas "is calculated as the weighted average price of wellhead sales of comparable gas in the taxpayer's market area." Exxon I, 88 F.3d at 976. Given our determinations, *supra*, regarding the relevant market area in 1975 and the comparability of gas produced generally in such market area to the Exxon gas well gas in issue, the court must now determine the composition of the RMFP sample -- the sample of wellhead sales on which the weighted-average RMFP calculation shall be made. In making this determination, the fundamental question is how many of the 2,058 transactions proffered by Exxon were truly "wellhead sales." We begin by consulting the relevant precedents for guidance as to the operative definition of a wellhead sale for purposes of the RMFP computation.

A. *Operative Definition Of A "Wellhead Sale"*

For purposes of the RMFP computation, a wellhead sale is a transaction in which the value of the raw natural gas has not been enhanced, prior to sale, by post-production processes such as transportation, compression, dehydration, or processing for the extraction of liquefiable hydrocarbons. Exxon I, 88 F.3d at 976, 33 Fed. Cl. at 275-77; Hugoton I, 161 Ct. Cl. at 277, 315 F.2d at 869. A wellhead sale is thusly defined because percentage depletion "was designed not to recompense for costs of recovery but for exhaustion of mineral assets alone." Cannelton, 364 U.S. at 88. See also id. at 86; Hugoton II, 172 Ct. Cl. at 455-56, 349 F.2d at 425. In other words, as Judge Learned Hand observed in an early percentage depletion case, "we are not justified in injecting into the 'basis' [for percentage depletion] the added value imparted to the [gas] by work done upon it after it reaches the surface." Consumers, 78 F.2d at 161.

In applying the aforementioned principle, so as to determine whether a transaction in issue was a wellhead sale, our analysis proceeds in two steps. First, the court must ascertain the physical location of the point of delivery, *i.e.*, the point of sale, relative to the wellhead. As explicated above, in a typical sale of gas by a producer to a pipeline company in 1975, the producer had to transport, or gather, the gas from its well(s) to the point of delivery, where the pipeline purchaser took title to the gas. Therefore, the proximity of the delivery point to the wellhead determines the distance over which the gas was transported, prior to sale, and the value added to the gas, if any, by such transportation. Second, having determined the location at which the gas was delivered to the purchaser, the court must determine whether the gas was compressed, dehydrated, or processed prior to delivery.

With respect to the proximity of the delivery point to the wellhead, the term "wellhead sale" is, to a certain degree, a misnomer. In an engineering sense, the "wellhead" proper is the aggregation of valves and fittings, commonly known as the "Christmas tree," that sits directly atop the well bore. However, as a practical matter, buyers and sellers of natural gas do not arrange for delivery of the gas to take place at the precise situs of the Christmas tree. This is so because, upon exiting the wellhead, the full well stream ordinarily contains not only raw natural gas, but also liquids such as water, crude oil, or condensate (liquid hydrocarbons chemically analogous to crude oil). See Exxon I, 33 Fed. Cl. at 257 (similar findings, relative to 1974). So constituted, the full well stream is not marketable, because a mixture of gas and liquids cannot be accurately measured by a gas custody meter. Moreover, the Texas Railroad Commission requires the liquids in the full well stream to be separated from the raw gas prior to metering. Such separation is typically performed in the gas producer's field separator, a simple, gravity-driven mechanical device that is usually located within a few hundred feet of the wellhead.[(112)] Thus, the outlet of the field separator is the point nearest the wellhead at which a purchaser can take delivery of the raw gas.[(113)]

Consistent therewith, for purposes of computing the RMFP, a sale at the outlet of the producer's field separator is deemed the equivalent of a sale at the wellhead itself. Exxon I, 88 F.3d at 978; Panhandle, 187 Ct. Cl. at 151, 227, 236, 408 F.2d at 704. Although the aforesaid authorities do not explicate why this is so,[(114)] the preceding discussion suggests two rationales. First, it is evident that separation is not deemed to be a post-production activity that adds value to otherwise salable natural gas. Rather, separation is deemed to be a production activity that is required to make raw gas a marketable commodity, separate and distinct from the non-gas constituents of the full wellstream, *i.e.*, water, crude oil, or condensate. See Riddell v. Monolith Portland Cement Co., 371 U.S. 537, 538 (1963) (holding that "the statutory percentage depletion allowance . . . should be cut off at the point where the mineral first became suitable for industrial use or consumption"), quoted in Hugoton II, 172 Ct. Cl. at 453 n.16, 349 F.2d at 424 n.16; see also 172 Ct. Cl. at 455, 349 F.2d at 425 (noting that the RMFP of natural gas must be based upon raw gas "if marketable in that form") (citing Cannelton, 364 U.S. at 86).

Second, the act of transporting raw gas only a few hundred feet, from wellhead to separator, is evidently deemed to add no *material* value to such gas. That transportation of the gas a *minimal* distance from the wellhead, prior to sale, is not grounds for disqualifying a transaction from inclusion in the RMFP sample is fully in accord with Treas. Reg. § 1.613-3(a), which makes sales "in the immediate vicinity of the well," rather than sales "*at* the well," the analytical touchstone of the RMFP computation. Accordingly, given all of the foregoing, we conclude that for purposes of computing the RMFP, the term "wellhead sale" includes a sale of raw gas in which the delivery point is located at, meaning within a few feet of, the outlet of the separator appurtenant to the wellhead in question.(115)

In addition to the specific case in which raw gas is sold at the separator, Panhandle also defines a wellhead sale generally as a transaction involving the sale of raw gas at a delivery point "on the lease property *near the wellhead*." Panhandle, 187 Ct. Cl. at 137, 163, 172, 408 F.2d at 696, 711, 716 (emphasis added).(116) The "lease property" at issue in Panhandle was, of course, the acreage covered by the oil and gas lease that granted the producer the right to exploit the underlying natural gas deposit. Panhandle, 187 Ct. Cl. at 161, 238-240, 408 F.2d at 710. Further, Panhandle is in accord with the Tax Court's seminal Shamrock decision, wherein it was stated: "A wellhead sale of gas is a sale where the purchaser lays a line to receive the gas *at the wellhead on the lease*." Shamrock, 35 T.C. at 989 (emphasis added).(117) In short, Panhandle defines a qualifying wellhead sale as a sale of raw gas at a delivery point located "on the lease property near the wellhead," 187 Ct. Cl. at 137, 163, 172, 408 F.2d at 696, 711, 716, which includes a sale of raw gas at the separator appurtenant to the producer's well, 187 Ct. Cl. at 151, 175, 227, 236, 408 F.2d at 704, 718.(118) See also Exxon I, 88 F.3d at 978.

What the foregoing means, here at bar, is that in order to establish that any transaction in issue was a wellhead sale qualifying for inclusion in the RMFP computation, Exxon has the burden of proving that such a transaction was a sale of raw gas at a delivery point located on the pertinent lease and near the wellhead that produced such gas. However, in the case of a transaction wherein the purchaser of the gas was an *inter*state pipeline company, an evidentiary presumption lightens Exxon's burden somewhat. Specifically, as noted above, interstate pipeline companies were required to file annual reports (Form 2) with the Federal Power Commission (FPC) in 1975. Among other things, such annual reports list natural gas purchases made by the reporting pipeline company in 1975, including the seller's identity, the volume of gas purchased, the dollar amount paid, the Btu content of the gas, and the state and field, or county, in which each gas purchase took place. Further, the reporting pipeline company was required to categorize each of its gas purchases according to the location of the delivery point. Each such category was designated with an account number under the Uniform System of Accounts promulgated by the National Association of Regulatory Utility Commissioners (NARUC).(119) See Exxon I, 33 Fed. Cl. at 272 (similar findings, relative to 1974).

Of particular relevance, in a natural gas RMFP case, are gas purchases reported under NARUC Accounts 800 and 801. In 1975, the FPC defined such gas purchases as follows:

800 Natural gas well head purchases.

A. This account shall include the cost at well head of natural gas purchased from producers in gas fields or production areas where *only the utility's facilities are used in bringing the gas from the well head* into the utility's natural gas system.

* * * * *

801 Natural gas field line purchases.

A. This account shall include the cost, at point of receipt by the utility, of natural gas purchased in gas fields or production areas at points along gathering lines, and at points along the utility's transmission lines within field or production areas, exclusive of purchases at outlets of gasoline plants includible in account 802, where *facilities of the vendor or others are used in bringing the gas from the well head* to the point of entry into the utility's natural gas system.

18 C.F.R. part 201, Account 800 ¶ A, Account 801 ¶ A (1975) (emphasis added).(120) The critical distinction between an Account 800 transaction and an Account 801 transaction, as noted in Exxon I, "is that in Account 800 sales the *purchaser* transports the gas away from the wellhead; whereas in Account 801 sales, the *producer* transports the gas away from the wellhead." Exxon I, 33 Fed. Cl. at 273 (emphasis in original), quoted with approval, 88 F.3d at 977. Stated differently, Account 800 describes a transaction in which the purchaser transports the gas away from the wellhead, meaning that the delivery point is, by definition, at the wellhead. Conversely, in an Account 801 transaction, "the *producer* incurs costs for transporting the gas away from the wellhead" to the point of delivery. Exxon I, 33 Fed. Cl. at 273-74 (emphasis added). Such transportation, prior to sale, adds value to the gas. Exxon I, 88 F.3d at 977.

In Exxon I, the Federal Circuit delineated the evidentiary significance of transactions classified under Accounts 800 and 801, in an annual report filed by an interstate pipeline company with the FPC, as follows:

[W]e read Panhandle as creating a rebuttable presumption that filed annual reports constitute prima facie proof of the transactions they represent. Nonetheless, the parties remain free to rebut this presumption with proof that the forms conflict with the underlying contracts. Moreover, the parties remain free to disagree as to which FPC transactions should be included in the RMFP calculation.

Id. at 977 (citing Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05). Thus, under Panhandle, the court must "presume that the FPC forms are representative of their underlying transactions," Exxon I, 88 F.3d at 979, meaning that an Account 800 transaction is presumed to qualify as a wellhead sale. An Account 801 transaction, on the other hand, is presumed to be tainted by the value added to the gas, prior to sale, by transportation away from the wellhead. Id. at 977-78. The Panhandle presumption is rebuttable, however, because "obvious errors in the information shown in the [FPC] forms, as established by actual reference to the contracts involved, must be corrected. To disregard such errors and fail to reflect them in the computation of the weighted-average prices determined here would be unjustified and improper." Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 705, cited with approval in Exxon I, 88 F.3d at 979 ("Either party may rebut this presumption with proof that some of the transactions listed in the forms are not representative [of the true character of the underlying transactions].").(121)

Thus, with respect to any transaction wherein the purchaser was an *inter*state pipeline company, the Panhandle presumption permits Exxon to demonstrate, subject to rebuttal, that such transaction was a wellhead sale by producing the purchaser's 1975 annual report (Form 2), as filed with the FPC, and showing that such transaction was reported therein under Account 800. Exxon I, 88 F.3d at 977.[(122)] The Panhandle presumption is inapplicable, however, to transactions in which the purchaser was an *intra*state pipeline company. Intrastate pipeline companies were not required to file annual reports with the FPC in 1975. Rather, intrastate pipeline companies fell under the jurisdiction of, and filed their annual reports with, the Gas Utilities Division (GUD) of the Texas Railroad Commission, which did not require the NARUC Uniform System of Accounts to be used until 1977. See Exxon I, 33 Fed. Cl. at 272-73 (similar findings, relative to 1974). Neither litigant has cited, and we have not found, any authority for extending the Panhandle presumption to GUD annual reports. Indeed, in Exxon I, the Federal Circuit noted the existence of both FPC and GUD annual reports, 88 F.3d at 977, but thereafter confined its remarks concerning the application of the Panhandle presumption exclusively to "FPC forms" and "FPC transactions." Exxon I, 88 F.3d at 977-79. Moreover, the 1975 GUD annual reports in evidence disclose that the Texas intrastate pipeline companies employed no standardized method of categorizing their 1975 gas purchases. In fact, only one significant intrastate pipeline company, Lone Star Gas Company, categorized its gas purchases as "wellhead" or "field line" purchases in its 1975 GUD annual report, in accordance with NARUC Accounts 800 and 801. However, as noted below, the record furnishes no justification for extending the Panhandle presumption to the Account 800 and 801 designations in Lone Star's 1975 GUD annual report.

To summarize all of the foregoing, with respect to the issue of transportation of the gas away from the wellhead, prior to sale, there are three ways that Exxon can prove that a transaction in issue was a wellhead sale. First, in the case of an *inter*state transaction, *i.e*., a transaction in which the purchaser of the gas was an interstate pipeline company subject to FPC jurisdiction, Exxon can show that the purchaser's 1975 annual report (Form 2), as filed with the FPC, reported such transaction under Account 800. Exxon I, 88 F.3d at 977; Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05. Of course, the Government can rebut such a showing by demonstrating that the Account 800 designation conflicts with the underlying transaction, in that the producer transported the gas a material distance away from the wellhead before sale. Exxon I, 88 F.3d at 977, 979; Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 705.

Second, Exxon can produce the gas purchase contract relating to *any* transaction in issue, interstate or intrastate, and show that the contractually specified delivery point was located at the wellhead. Exxon I, 88 F.3d at 977; Panhandle, 187 Ct. Cl. at 151, 408 F.2d at 704 (transactions shown to be wellhead sales by reference to underlying contracts). For this purpose, the term "wellhead" includes the outlet of the field separator appurtenant to the producer's well. Exxon I, 88 F.3d at 978; Panhandle, 187 Ct. Cl. at 151, 175, 227, 236, 408 F.2d at 704, 718.

Third, if the underlying gas purchase contract specifies a delivery point further removed from the wellhead than the appurtenant separator, or describes the delivery point in ambiguous terms, Exxon can present evidence showing that the delivery point was nonetheless located "on the lease property *near the wellhead*." Panhandle, 187 Ct. Cl. at 137, 163, 172, 408 F.2d at 696, 711, 716 (emphasis added). By this, we mean that Exxon can prove that a transaction was the factual equivalent of a wellhead sale, by showing that the transportation of the gas prior to sale, away from the wellhead and to the delivery point, added no *material* value to the gas.

Even assuming that Exxon can establish that a transaction in issue met one of the aforesaid three requirements, relative to transportation, that does not complete our inquiry into the qualification of such transaction for inclusion in the RMFP computation. Instead, as noted above, the court must also ascertain whether the gas was compressed, dehydrated, or processed prior to sale. Transactions involving the sale of gas that was processed, for the purpose of extracting liquefiable hydrocarbons, are unconditionally disqualified from inclusion in the calculation of the RMFP, which must reflect the "price of the . . . gas *before* [its] conversion" into a refined product. Treas. Reg. § 1.613-3(a) (emphasis added). See Cannelton, 364 U.S. at 86; Exxon I, 88 F.3d at 976; Hugoton II, 172 Ct. Cl. at 455-56, 349 F.2d at 425.

Prior to the Federal Circuit's decision in Exxon I, it also seemed equally clear that compression or dehydration, prior to sale, likewise compelled disqualification of a transaction. Exxon I, 88 F.3d at 978; 33 Fed. Cl. at 275 (citing Shamrock, 35 T.C. at 1037). Similarly, transportation of the gas a material distance away from the wellhead, prior to sale, compelled disqualification. Exxon I, 88 F.3d at 976 (citing Panhandle, 408 F.2d at 716). However, in Exxon I, the Federal Circuit observed that "in light of the goal of maximizing the number of transactions included" in the RMFP computation, it would be "preferable" to cure "tainted" transactions, not otherwise qualifying as wellhead sales, by subtracting the costs of transportation, dehydration and, by necessary implication, compression, from the sale price. Exxon I, 88 F.3d at 977-78. Yet, the foregoing observation was not essential to the holding in Exxon I -- and, therefore, dicta -- inasmuch as the Federal Circuit expressly affirmed, as not clearly erroneous, the trial court's ruling that such "tainted" transactions must be excluded from the RMFP computation. Id. at 977-78.[(123)]

At this juncture, we raise the subject of Exxon I's "preferable" method of dealing with "tainted" transactions solely to furnish context to the discussion below. Before revisiting the "preferable" method, *infra*, the court must first delineate the extent to which the 2,058 transactions proffered by Exxon were, in fact, "tainted" by transportation, compression, dehydration, or processing of the gas, prior to sale. We begin said analysis with the issue that fueled the most heated controversy at trial -- the effect that transportation of the gas, prior to sale, has upon the qualification of a transaction for inclusion in the RMFP computation.

B. *Transportation Of The Gas Prior To Sale*

1. *Contentions Of The Parties*

Exxon's basic contention is that any transaction involving the sale of raw gas at a delivery point located *anywhere* "on the lease" qualifies as a wellhead sale, *i.e.*, a sale of raw gas "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a).[(124)] Simply stated, by "on the lease," Exxon means the acreage covered by the producer's oil and gas lease(s), the gas production from which was dedicated to the gas purchase contract relating to the transaction in question. Despite its seeming simplicity, however, there is more than meets the eye to Exxon's "on-the-lease criterion," as denoted herein.

This is so because Exxon's experts, in applying their hospitable on-the-lease criterion to identify wellhead sales, gave the regulatory term "in the immediate vicinity of the well" a very broad interpretation. See Exxon I, 33 Fed. Cl. at 273 (similar finding, relative to 1974). For example, Mr. Ellis, Exxon's principal expert on the computation of the RMFP, testified that it makes no difference whether the lease in question is 10 acres or 10,000 acres. In either case, Mr. Ellis opined, a delivery point falling *anywhere* within the boundaries of the lease is in "the immediate vicinity of the well."[(125)] Moreover, Exxon's on-the-lease criterion rests upon a hospitably expansive construction of the term "lease," in that the physical area encompassed by the "lease" is not limited to the metes and bounds of a single, common-law mineral lease. Rather, the "lease" includes *all* of the gas producer's leased acreage that has been dedicated to the gas purchase contract underlying the transaction in issue. So conceived, the "lease" can, and frequently does, include multiple contiguous tracts leased by the gas producer, often from different lessors, aggregated into a larger area.[(126)]

The significance of Exxon's expansive definitions of "the immediate vicinity of the well," and the "lease," pertains to the distance over which the producer transports, or gathers, the gas away from the well prior to sale. As explained above, gathering is the act of transporting gas from the outlet of the producer's field separator to the purchasing pipeline company's nearest transmission line. Any gathering of the gas from the separator appurtenant to the producer's well, to the contractually specified point of delivery to the purchaser, is the obligation of the producer. Further, it is not uncommon in the natural gas industry for producers to construct and operate gathering systems that gather the gas from multiple wells to a central delivery point. Exxon's on-the-lease criterion for identifying wellhead sales disregards all such gathering to the extent it occurs on the "lease," as defined by Exxon.

A hypothetical gas sale transaction, addressed by Mr. Eakin at trial, will illustrate why this is so. Counsel for defendant proposed a transaction in which the gas producer had 38 wells, situated on multiple adjoining common-law leases, and had constructed a gathering system in order to connect those 38 wells to a central delivery point located on one of those multiple leases. In response, Mr. Eakin opined that such a transaction would be properly categorized as a "wellhead sale," irrespective of the gathering performed by the producer prior to sale, because it would satisfy the on-the-lease criterion, *i.e.*, the central delivery point was located on one of the producer's multiple leases.[(127)] Speaking generally, Mr. Eakin explained that when a producer has multiple leases dedicated to a gas purchase contract, the on-the-lease criterion requires only that the gas was delivered at a point located anywhere within any one of the multiple leases in question, not at individual delivery points located within each individual lease.[(128)]

Given the foregoing, it is evident that Exxon's on-the-lease criterion fails to take account of the actual distance between the wellhead and the delivery point. On the contrary, this approach simply presumes that every transaction with a delivery point literally on the "lease," broadly defined by Exxon to permit the aggregation of many smaller leases, is the factual equivalent of a sale of gas "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). Exxon's position, in a nutshell, is that when the producer transports its gas within the boundaries of the "lease," so defined, such on-the-lease transportation, whatever the distance and the cost, adds no material value to the gas.[(129)]

In contrast, Exxon concedes that when the producer transports the gas away from the wellhead, or wellheads, to a delivery point located *outside* the boundaries of the "lease," as defined above, the off-the-lease segment of such transportation does add value to the gas. According to Exxon, such off-the-lease transportation adds only a flat $0.01/Mcf to the value of the gas, regardless of how much gas is involved, or how far such gas is actually transported beyond the boundaries of the "lease." Exxon concedes, further, that an off-the-lease transaction fails to qualify as a wellhead sale, but maintains that such a transaction is properly includible in the RMFP computation, under the "preferable" method enunciated by the Federal Circuit in Exxon I, 88 F.3d at 977-78, so long as the sale price of the gas is reduced by $0.01/Mcf. Thus, in Exxon's view, transportation from the wellhead to the edge of the lease is always valueless, but transportation from the edge of the lease to an off-the-lease delivery point adds value in the sum of only $0.01/Mcf, regardless of the actual distances involved.

Exxon advances several arguments in support of its on-the-lease criterion. First, Exxon contends that in Exxon I, the Federal Circuit implicitly adopted the on-the-lease criterion when it computed the 1974 RMFP on the basis of 24 transactions that Mr. Ellis had identified as wellhead sales. See Exxon I, 88 F.3d at 978-79 & n.9. Here at bar, Mr. Ellis testified that his on-the-lease criterion is the same one he used for purposes of the 1974 RMFP study he submitted in Exxon I. As a consequence, argues Exxon, the doctrine of collateral estoppel bars the Government from relitigating the validity of the on-the-lease criterion.

Second, Exxon asserts that its on-the-lease criterion flows from a plain reading of Treas. Reg. § 1.613-3(a). Exxon points out that said Regulation prescribes only two ways of computing percentage depletion: (i) on the actual sales price, if the gas is sold "in the immediate vicinity of the well"; or (ii) under the RMFP method, if "the gas is not sold on *the premises*," but instead is "transported from *the premises* prior to sale." Treas. Reg. § 1.613-3(a) (emphasis added). Logically, Exxon submits, the areas delineated by "immediate vicinity of the well" and the "premises" must be coterminous, for otherwise there would exist a regulatory "gap" -- specifically, an area situated beyond "the immediate vicinity of the well," but within the "premises" -- in which certain transactions might fall, passing outside the express scope of Treas. Reg. § 1.613-3(a). According to Exxon, the Court of Claims addressed this interpretive issue by adopting the on-the-lease/off-the-lease distinction between wellhead sales and non-wellhead sales, in Panhandle, 187 Ct. Cl. at 148, 151, 161, 164, 171-75, 408 F.2d at 703, 704, 710, 712, 716-18. Thus, Exxon favorably concludes, a sale of gas "on the lease," broadly defined to include an aggregation of multiple common-law mineral leases, is synonymous with a sale of gas "on the premises," within the meaning of Treas. Reg. § 1.613-3(a).

Third, Exxon maintains that its on-the-lease criterion conforms to regulatory and industry practice in 1975. Specifically, Exxon argues that as of 1975, interstate pipeline companies classified their gas purchases under NARUC Accounts 800 or 801, in their FPC annual reports (Forms 2), in accordance with the on-the-lease/off-the-lease distinction. Further, Exxon asserts that the regulatory phrase "immediate vicinity of the well" is not used in natural gas contracting, whereas the regulatory phrase "on the premises" is commonly used. In support of its contention that the natural gas industry considers "the premises" to mean "the lease," Exxon asserts that the Texas Supreme Court adopted such a definition in a case arising from a natural gas royalty dispute, Exxon Corp. v. Middleton, 613 S.W.2d 240, 243 (1981).

Responding to the foregoing, the Government contends that Exxon's on-the-lease criterion has no basis in fact or law. Factually, the Government argues, the delivery point must be within 500 feet of the wellhead, because the only commercial reasons for setting the custody meter, which measures the volume of gas the producer delivers to the purchaser, more than 500 feet from the well are: (i) to gather the gas from multiple wells to a central delivery point; or (ii) to deliver the gas at a point more convenient to the purchaser. The Government asserts that, in either case, the transaction is not a wellhead purchase of gas, *i.e*., a NARUC Account 800 transaction, but rather, a field line purchase, *i.e*., an Account 801 transaction. Further, the Government argues that the FPC and the natural gas industry have never applied Accounts 800 and 801, as set forth in 18 C.F.R. part 201, so as to differentiate wellhead purchases of gas from field line purchases in accordance with an on-the-lease/off-the-lease distinction.

Legally, the Government contends, Exxon's on-the-lease criterion is flatly contrary to the construction given Accounts 800 and 801 in Exxon I, 88 F.3d at 977. In addition, the Government argues that Exxon not only misreads Panhandle as authorizing the use of an on-the-lease criterion to identify qualifying wellhead sales, but also disregards an unbroken line of natural gas RMFP cases -- Exxon I, Panhandle itself, Hugoton II, Hugoton I, and Shamrock, *supra* -- consistently holding that the RMFP must be computed on the basis of sales of raw gas at the wellhead. The Government points out that none of the foregoing precedents expresses the view that the term "in the immediate vicinity of the well," as set forth in Treas. Reg. § 1.613-3(a) and its predecessors, means "anywhere on the lease," as Exxon would have it. Moreover, the Government asserts that Exxon is not entitled to include non-wellhead sales in the RMFP computation, after deducting the cost of transportation from the sales price, in reliance upon the Federal Circuit's remarks concerning the "preferable" method, enunciated in dicta in Exxon I, 88 F.3d at 977-78.

Further, the Government contests, on two grounds, Exxon's assertion that under the doctrine of collateral estoppel, Exxon I conclusively established the validity of the on-the-lease criterion. First, given the enactment of § 613A into law, effective January 1, 1975, the Government argues that collateral estoppel is inapplicable because the controlling statutory law changed between 1974 and 1975. Second, the

Government vehemently contends that collateral estoppel is inapplicable because the validity of Exxon's on-the-lease criterion was not actually litigated and decided in Exxon I.

Relative to its second contention, the Government raises a startling allegation concerning the appellate proceedings in Exxon I. Specifically, as noted above, the Federal Circuit held that the Court of Federal Claims committed reversible error "by truncating its RMFP analysis thus not reaching the issue of whether Exxon's [RMFP] study contained any valid transactions from which an RMFP could be determined." Exxon I, 88 F.3d at 979. However, the Federal Circuit determined that it was unnecessary to remand the case for the calculation of the 1974 RMFP, "because the *undisputed* evidence of record supports an RMFP in the amount of $0.39/Mcf." Id. (emphasis added). The "undisputed" evidence at issue, on which the Federal Circuit based its RMFP calculation, id. at 979 & n.9, consisted of 24 transactions that Mr. Ellis' 1974 RMFP study presented as untainted wellhead sales, *i.e.*, "pre-dehydration, pre-compression, Account 800 sales." Id. at 978-79. In selecting the aforementioned 24 transactions, the Federal Circuit considered and rejected "the government['s] argu[ment] that . . . the Account 800 sales reported on the FPC forms may not have been wellhead sales." Id. at 978. By way of explanation, the Federal Circuit stated:

As explained above [88 F.3d at 977], . . . we presume that the FPC forms are representative of their underlying transactions. Either party may rebut this presumption with proof that some of the transactions listed in the forms are not representative. Cf. Panhandle, [187 Ct. Cl. at 152], 408 F.2d at 704 (allowing an adjustment because gas purchased at the wellhead was erroneously listed as non-wellhead sales). In the present case, however, the government has made no showing of proof to rebut the FPC transactions which meet the Court of Federal Claims' criteria [for a wellhead sale]. Therefore, in the present case, the [24] pre-dehydration transactions listed in Account 800 may properly be used to calculate the RMFP.

Exxon I, 88 F.3d at 979. As the foregoing passage from the Exxon I opinion makes clear, the Federal Circuit viewed its selection of 24 "undisputed" transactions for inclusion in the 1974 RMFP computation as a straightforward application of the Panhandle presumption, *i.e.*, that transactions reported under Account 800, in an interstate pipeline company's annual report (Form 2) filed with the FPC, are rebuttably presumed to be wellhead sales. See id. at 977; Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05.

Here at bar, the Government alleges that the Federal Circuit was "duped" into applying the Panhandle presumption to 23 of the 24 transactions at issue in Exxon I, because those 23 transactions were, in fact, *intra*state transactions that had never been reported under Account 800 to the FPC in a duly filed Form 2. Specifically, in its post-trial reply brief, the Government argues as follows:

As we understand the underpinnings of Exxon's argument in this case, it is now telling this Court what it obviously did not make clear to the Federal Circuit in Exxon I -- that the sales that its expert (Ellis) in Exxon I classified for his own purposes as "Account 800" and "Account 801" did not meet the same criteria by which the FPC classified sales as "Account 800" and "Account 801." That is, whereas the FPC considered an "Account 800" sale in which the purchaser transported the gas away from the wellhead, Mr. Ellis labeled as an "Account 800" sale for his purposes any inter- or intrastate sale made anywhere on the lease (that is, including those in which the producer transported the gas away from the wellhead). Yet, Exxon represented to the Federal Circuit that Mr. Ellis's "Account 800" sales, from which the Federal Circuit extracted the 24 sales that it used to calculate the [1974] RMFP, "met the court's criteria for a 'wellhead sale' -- namely, classification under [the FPC's] Account 800 [criteria] . . . ." In other words, Exxon is actually contending that this Court is required to hold that all of Mr. Ellis' questionable samples in this case (including those that are clearly non-wellhead sales) are all "wellhead sales," because the Federal Circuit was *duped* into believing that Mr. Ellis's similar samples in Exxon I met the criteria established in Panhandle. As discussed previously, however, even if the Federal Circuit had realized that the so-called Account 800 sales did not in fact "meet the court's criteria," it could not knowingly have included those in its RMFP sample consistently with the holding of the Court of Claims in Panhandle that it purported to follow.

Post-Trial Reply Brief For The United States (Def. Reply), filed May 18, 1998, at 18 (emphasis added) (quoting, with alterations, Pl. Brf. at 26).[(130)] The Government states, further, that:

[T]he [Exxon I appellate] panel stated that it compiled a list of 24 qualified transactions (listed at 88 F.3d at 979, n.9) by identifying transactions listed in *both* Exxon's exhibit 45 -- a list of pre-dehydration sales, and the first three pages (which it said were limited to Account 800 sales) of Exxon's exhibit 29 -- a list of pre-compression sales. Id. at 978. . . . In compiling its list of 24 transactions using the above procedure, the appellate panel simply made a mistake. . . . At [88 F.3d at 979 n.9], the panel listed 24 transactions that it stated met the foregoing criteria. Those transactions did not meet the court's stated criteria because only one of them was an Account 800 sale. Only *inter*state gas sales are reported in Account 800 of the Uniform System of Accounts . . . (18 C.F.R. Part 201). Of the 24 transactions, only one was an interstate purchase. Only that purchase had been reported to the Federal Power Commission on FPC Form 2 as Account 800 wellhead sale purchases [sic]. (This is simply a factual error objectively verifiable from the text of the opinion and the record, and does not negate the opinion of the appellate panel.)

Defendant's Response To Plaintiffs' Report Of Their Collateral Estoppel Contentions, filed January 9, 1998, at 8-9 (emphasis in original).[(131)] The essence of the Government's argument is that 23 of the 24 transactions included in the 1974 RMFP computation, Exxon I, 88 F.3d at 979 n.9, failed to meet the Federal Circuit's own stated criteria and, further, that the Federal Circuit's purported "mistake" was the product of Exxon's failure to disclose the true character of those 23 transactions.[(132)] Thus, the Government concludes, the foregoing alleged circumstances compel the conclusion that the validity of Exxon's on-the-lease criterion was not actually litigated and decided before the Federal Circuit in Exxon I, such that the doctrine of collateral estoppel does not bar the litigation of that issue in the case at bar.

This court, having duly considered the parties' intricate contentions regarding the operative definition of a wellhead sale, including the preclusive effect of Exxon I with respect to that issue, agrees with the Government that collateral estoppel is inapplicable and, further, that Exxon's on-the-lease criterion is without foundation in law or fact. However, as explained below, we likewise reject the Government's contention that a wellhead sale must be defined so as to exclude transactions occurring more than 500 feet from the wellhead. Even so, despite the failure of the litigants to establish a tenable legal definition of a wellhead sale, the court has ascertained that Exxon's 2,058-transaction proposed RMFP sample contains a sizable number of transactions in which the contractually-specified point of delivery to the purchaser was "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). All of the foregoing is explicated in greater detail below, with the discussion focusing initially upon Exxon's collateral estoppel argument. As a prelude to that discussion, the court deems it prudent and necessary to delineate the precise character of the 2,058 transactions in issue.

2. *De Jure Account 800 Transactions v. De Facto Account 800 Transactions*

In order to fully understand the character of the 2,058 transactions in Exxon's RMFP sample, one must first draw a distinction between *de jure* Account 800 transactions and *de facto* Account 800 transactions.[(133)] A *de jure* Account 800 transaction is a gas purchase that an interstate pipeline company classified under NARUC Account 800 in a 1975 annual report (Form 2) filed with the FPC. As noted above, under the Panhandle presumption, such transactions are rebuttably presumed to be wellhead sales, *i.e*., sales "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). Exxon, 88 F.3d at 977; Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05. Similarly, a *de jure* Account 801 transaction is a "field line" (*i.e*., non-wellhead) gas purchase reported as such by an interstate pipeline company in a 1975 FPC annual report. *De jure* Account 801 transactions do not qualify as wellhead sales. Exxon I, 88 F.3d at 977. Neither litigant has attempted to rebut the Panhandle presumption in connection with any of the *de jure* Account 800 transactions in issue.[(134)] Instead, both parties relied upon said presumption in selecting transactions for inclusion in their respective RMFP samples.

A *de facto* Account 800 transaction, on the other hand, is everything else that Exxon contends to be a wellhead sale. Such *de facto* Account 800 transactions fall into two classes. First, Mr. Ellis' RMFP study includes 46 *de jure* (interstate) Account 801 transactions that he redesignated as *de facto* Account 800 transactions.[(135)] It is Mr. Ellis' contention that these 46 transactions were on-the-lease gas purchases, and that the interstate pipeline companies in question erred in classifying these 46 transactions under Account 801 in their 1975 FPC annual reports. However, Mr. Ellis admitted that he had no idea why these 46 transactions had been reported to the FPC under Account 801, since he contacted none of the pertinent interstate pipeline companies to make inquiry about such matters.[(136)] Therefore, Mr. Ellis' redesignation of these 46 transactions as *de facto* Account 800 transactions was based exclusively upon his subjective judgment that such transactions met Exxon's on-the-lease criterion.[(137)]

Second, Exxon argues that numerous gas purchases by *intra*state pipeline companies, never reported to the FPC in a 1975 Form 2 filing, were the factual equivalents of *de jure* Account 800 transactions. Such transactions include: (i) generally, all intrastate gas purchases satisfying Exxon's on-the-lease criterion; (ii) intrastate gas purchases that Lo-Vaca Gathering Company classified in its internal accounting records under "Account 41," a putative equivalent of NARUC Account 800; and (iii) gas purchases classified under Account 800 by Lone Star Gas Company, the only intrastate pipeline company to voluntarily utilize the NARUC Uniform System of Accounts in its 1975 GUD annual report. Most of the foregoing intrastate *de facto* Account 800 transactions were designated as such by Mr. Ellis, based upon his review of the underlying contract files. As noted above, the gas purchase contract files of Houston Pipe Line Company and Lo-Vaca Gathering Company were reviewed by Messrs. Buie and Eakin, respectively, on whose work Mr. Ellis relied. All three experts classified on-the-lease transactions as *de facto* Account 800 transactions, and off-the-lease transactions as *de facto* Account 801 transactions. Moreover, in the case of certain Lo-Vaca gas purchases for which the contract was missing, or ambiguous as to the delivery point, Mr. Eakin relied upon the classification of such transactions under Account 41 in Lo-Vaca's accounting records. This approach produced results consistent with the on-the-lease criterion, Mr. Eakin asserted, because Lo-Vaca's Account 41 was intended to collect gas purchases with on-the-lease delivery points.[(138)] As to gas purchases made by Lone Star Gas Company, Exxon's post-trial submissions suggest that Mr. Ellis relied upon Lone Star's *de facto* Account 800 classifications in its 1975 GUD annual report. However, upon retiring to examine the record, the court discovered that Mr. Ellis was less deferential to Lone Star's *de facto* Account 801 gas purchases, finding that his RMFP study redesignates eight such transactions as *de facto* Account 800 transactions, presumably on the basis of Exxon's on-the-lease criterion.[(139)]

What must be kept in mind, relative to the aforesaid *de facto* Account 800 transactions, is that *none* of these transactions was, in fact, reported under Account 800 in a 1975 Form 2 annual report filed with the FPC. On the contrary, such *de facto* Account 800 transactions are nothing more than the product of subjective judgments, reached by Messrs. Ellis, Buie, and Eakin, that such transactions were the factual equivalents of *de jure* Account 800 transactions. The fundamental distinction is that the *de jure* Account 800 transactions in issue were designated as such in filings that interstate pipeline companies were required by law to make with the FPC, whereas the *de facto* Account 800 transactions in issue have been designated as such in Mr. Ellis' RMFP study, prepared in anticipation of litigation. Consequently, it is clear beyond cavil that such *de facto* Account 800 transactions are *not* entitled to the rebuttable presumption of correctness laid down in Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05, and Exxon I, 88 F.3d at 977.[140] Rather, it is Exxon's threshold burden to affirmatively establish, by a preponderance of the evidence, that each such *de facto* Account 800 transaction did, in fact, occur "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). Under the standards delineated above, Exxon can meet its burden by showing that the gas was sold either: (i) at the wellhead, including the outlet of the appurtenant separator; or (ii) at a delivery point located elsewhere "on the lease property," but yet "near the wellhead," Panhandle, 187 Ct. Cl. at 137, 163, 172, 408 F.2d at 696, 711, 716, such that no material value was added to the gas by transportation, prior to sale.

The qualification of such *de facto* Account 800 transactions for inclusion in the RMFP computation has spawned enormous controversy, here at bar. Indeed, no other issue was so hotly contested at trial, and at such length. So as to clarify what is in dispute, and what is not, we find it helpful to categorize the 2,058 transactions in Exxon's proposed RMFP sample, as follows:

Designation in

Ellis RMFP Study Number of

Character of Transaction (PX 6, SubX G) Transactions

De jure Account 800 transactions "Account 800 -- Interstate" 158

De jure Account 801 transactions, "Account 800 -- Interstate" 46

redesignated as *de facto* Account 800

transactions by Mr. Ellis

_____

Subtotal, transactions designated 204

"Account 800 -- Interstate"

De jure Account 801 transactions "Account 801 -- Interstate" 774

_____

Subtotal, all interstate transactions 978

De facto Account 800 transactions "Account 800 -- Intrastate" 445

De facto Account 801 transactions "Account 801 -- Intrastate" 635[(141)]

Subtotal, all intrastate transactions 1,080

Total, all transactions 2,058.

Of these 2,058 transactions, the parties have only agreed that 170 of them qualify for inclusion in the RMFP computation. Both parties include the 158 *de jure* Account 800 transactions in their respective RMFP samples.[(142)] In addition, the Government has conceded that 12 of the 445 intrastate transactions designated in Mr. Ellis' report as *de facto* Account 800 transactions qualify as wellhead sales. Eleven of such transactions appear in the Government's own RMFP sample.[(143)] The twelfth such transaction is undisputed by virtue of the Government's stipulation, at trial, that the producer in that transaction added no value to the gas by transporting it from the several wells in question to a central delivery point.[(144)]

Notwithstanding the foregoing, the Government disputes the qualification of every other transaction in Mr. Ellis' study -- 1,888 transactions, to be exact -- for inclusion in the RMFP computation. The immediate question, relative to Exxon's collateral estoppel argument, pertains to the 479 *de facto* Account 800 transactions that are in dispute, consisting of: (i) 46 *de jure* (interstate) Account 801 transactions redesignated by Mr. Ellis as *de facto* Account 800 transactions; and (ii) 433 of the 445 *de facto* (intrastate) Account 800 transactions listed in Mr. Ellis' report (the other 12 of which the Government concedes to be wellhead sales).[(145)] With respect to the 479 *de facto* Account 800 transactions in dispute, the precise question for decision is whether a *de facto* Account 800 transaction, identified as such by Mr. Ellis in accordance with Exxon's on-the-lease criterion, is the factual equivalent of a *de jure* Account 800 transaction. We now turn to Exxon's contention that Exxon I conclusively answered the foregoing question in the affirmative, such that the doctrine of collateral estoppel precludes the Government from relitigating that question in the case at bar.[(146)]

C. *Collateral Estoppel And Plaintiff's On-The-Lease Criterion*

At the outset, we are constrained to observe that, even if the court were to hold that collateral estoppel is properly applicable, here at bar, in connection with the asserted validity of Exxon's on-the-lease criterion, *supra*, Exxon's expectations regarding the consequences of such a holding are implausibly optimistic. Such a holding would *not* put the qualification of the *de facto* Account 800 transactions in issue beyond all controversy. On the contrary, the very *most* that Exxon could accomplish, as the beneficiary of a meritorious assertion of collateral estoppel, would be to elevate each of the 479 *de facto* Account 800 transactions in dispute, identified as such pursuant to Mr. Ellis' determination that the underlying contract specifies a delivery point "on the lease," to the status of a *de jure* Account 800 transaction, classified under NARUC Account 800 in a Form 2 annual report duly filed with the FPC. In such case, *de jure* Account 800 status merely gives rise to a presumption that the *purchaser*, not the producer, transported the gas away from the wellhead. Exxon I, 88 F.3d at 977. That presumption is *rebuttable*, however. Id. Therefore, even in the case of *de jure* Account 800 transactions reported as such to the FPC, "*the parties remain free to disagree* as to which FPC transactions should be included in the RMFP calculation." Id. (emphasis added). Consequently, even assuming that collateral estoppel were applicable, the qualification of a *de facto* Account 800 transaction as a wellhead sale would, as with any *de jure* Account 800 transaction, still be rebuttable by evidence tending to show that, in fact, the *producer*, not the purchaser, transported the gas away from the wellhead(s). Id.

Exxon has never suggested that for the purpose of identifying wellhead sales, its on-the-lease criterion is more accurate than, or supersedes, the Account 800 standard expressly approved in Exxon I, *i.e*., a showing that the purchaser transported the gas away from the wellhead(s). Rather, Exxon insists that its on-the-lease criterion and the Account 800 standard lead to exactly the same result. Thus, given Exxon I's unequivocal holding that *de jure* Account 800 transactions are subject to challenge, Exxon's contention that Exxon I somehow transforms the 479 *de facto* Account 800 transactions in dispute into transactions that irrebuttably qualify as wellhead sales, under the doctrine of collateral estoppel, is patently absurd and without merit.

Turning now to address the merits of Exxon's collateral estoppel argument with respect to the aforesaid issue, *i.e*., whether a *de facto* (on-the-lease) Account 800 transaction is the factual equivalent of a *de jure* Account 800 transaction, we begin with the requirement that Exxon, as the proponent of collateral estoppel, must demonstrate that the validity of its on-the-lease criterion was actually litigated and decided in Exxon I, and was essential to the final judgment therein. Arkla, 37 F.3d at 624. Seeking to establish that the aforesaid issue was, in fact, litigated and decided in the Exxon I trial proceedings, Exxon argues that:

In the trial court, Judge Lydon expressly recognized the existence of what this Court has described as "*de jure*" and "*de facto*" Account 800 transactions, referring to "Account 800 and Account 801 transactions and their GUD [Gas Utility Division] equivalent." . . . Judge Lydon drew no distinction between the NARUC classifications and their GUD (intrastate) equivalents; his analysis consistently lumped together all transactions classified by Mr. Ellis as Account 800 type transactions.

Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 4 (quoting, with alteration, Exxon I, 33 Fed. Cl. at 273, and citing generally id. at 273-74). Exxon seeks to assign the cited portions of the Exxon I trial opinion a meaning they cannot logically bear. Reproduced in full, the quoted sentence states: "Ellis included in his RMFP calculation both Account 800 and 801 transactions and their GUD equivalent based on the assumption that there are no economic or operational differences between Account 800 and Account 801 transactions." Exxon I, 33 Fed. Cl. at 273. Read in context, the foregoing sentence is part of a generalized description of the manner in which Mr. Ellis prepared his 1974 RMFP study, not a formal judicial finding that Mr. Ellis' *de facto* (intrastate) Account 800 transactions were the factual equivalents of *de jure* (interstate) Account 800 transactions, *i.e*., wellhead sales.(147) We are not convinced that the Court of Federal Claims, in making this innocuous descriptive statement, actually "decided" that Exxon's on-the-lease criterion was valid. On the contrary, that court found Mr. Ellis' 1974 RMFP study so gravely flawed that it expressly declined to make *any* findings of fact as to which of the 1974 transactions in controversy qualified as wellhead sales. Id. at 274, 275, 277, 278.

Nor does Exxon's nebulous contention, *supra*, that "Judge Lydon drew no distinction" between *de jure* and *de facto* Account 800 transactions but, rather, "consistently lumped together all transactions classified by Mr. Ellis as Account 800 type transactions," persuade us that the Court of Federal Claims implicitly accepted the validity of Exxon's on-the-lease criterion in Exxon I. The cited discussion in the Exxon I trial opinion, 33 Fed. Cl. at 273-74, addresses Mr. Ellis' hospitable "assumption that there [were] no economic or operational differences between Account 800 and Account 801 transactions." Id. at 273. In analyzing the economic difference between the two, in terms of pricing disparities, the court expressly distinguished between "*interstate and intrastate* Account 800 sales," as well as "*interstate and intrastate* Account 801 sales," and consistently maintained that interstate-intrastate distinction throughout its analysis. Id. (emphasis added). Thus, it is patently clear that Exxon wrongly contends that Judge Lydon simply "lumped together" *de jure* (interstate) Account 800 transactions with Mr. Ellis' *de facto* (intrastate) Account 800 transactions.

Similarly, in considering the "operational differences between the Account 800 and 801 classifications," Exxon I, 33 Fed. Cl. at 273, the Court of Federal Claims plainly did not "lump together" *de jure* and *de facto* Account 800 transactions. Rather, the court focused exclusively upon the distinction between NARUC Accounts 800 and 801, *as defined by the FPC* -- not by Mr. Ellis -- in 18 C.F.R. part 201, concluding that "in Account 800 sales the *purchaser* transports the gas away from the wellhead; whereas in Account 801 sales, the *producer* transports the gas away from the wellhead." Exxon I, 33 Fed. Cl. at 273 (emphasis in original), quoted with approval, 88 F.3d at 977. Having settled upon the aforesaid definition of a wellhead and non-wellhead sales, in accordance with the FPC Account 800 and 801 standards, the court went on to ultimately conclude as follows:

As noted, Exxon broadly construes the phrases "immediate vicinity of the well" and "wellhead sales." The sheer number of transactions and the lack of adequate data as to each transaction leaves the court unable to ascertain whether the sales [in Exxon's 1974 RMFP sample] truly are sales of raw gas in the immediate vicinity of the well.

Exxon I, 33 Fed. Cl. at 274. More importantly, the court's misgivings respecting Exxon's overly broad construction of the terms "immediate vicinity of the well" and "wellhead sale" stemmed, at least in substantial part, from Exxon's insistence that a "wellhead sale" can have a delivery point anywhere "on the lease." Id. at 273. We read the foregoing not as the Court of Federal Claims' implicit adoption of the on-the-lease criterion in Exxon I, as Exxon urges, but rather as that court's *rejection* of Exxon's position.

Further, even if we were to charitably assume that the validity of Exxon's on-the-lease criterion was actually litigated in the Exxon I trial proceedings, and decided in Exxon's favor, it is axiomatic that an incidental or collateral determination of an issue that is nonessential to the final judgment in a prior suit will not preclude the reconsideration of that issue in subsequent litigation. Russell v. Place, 94 U.S. (4 Otto) 606, 608, 610 (1876); Mother's Restaurant, Inc. v. Mama's Pizza, Inc., 723 F.2d 1566, 1571 (Fed. Cir. 1983). In Exxon I, the Court of Federal Claims' entry of judgment in the Government's favor was expressly premised upon Exxon's failure to meet its burden of proving that the 2,228 transactions in issue qualified as wellhead sales, as a consequence of "the sheer number of transactions and the lack of adequate data as to each transaction." Exxon I, 33 Fed. Cl. at 274. Therefore, even assuming that the trial court had ruled in Exxon's favor as to the validity of the on-the-lease criterion in Exxon I, the determination of that issue would have been nonessential to the final judgment, given Exxon's overall failure of proof, and would not preclude our reconsideration of that issue, here at bar. Accordingly, given that the validity of Exxon's on-the-lease criterion was not actually litigated and decided, nor essential to the final judgment, in the Exxon I trial proceedings, Exxon's collateral estoppel argument cannot prevail unless it is shown that the Federal Circuit adopted the on-the-lease criterion in Exxon I, 88 F.3d 968.

Exxon's fundamental dilemma is that the Federal Circuit's Exxon I opinion, 88 F.3d 968, nowhere mentions the word "lease," nor any derivatives thereof (*e.g.*, "leasehold").[(148)] We are, of course, in no position to read the term "lease" into that opinion. Cognizant of this point, Exxon nonetheless argues that the Federal Circuit took notice of Exxon's on-the-lease criterion, and *implicitly* held that a *de facto*

Account 800 transaction is the factual equivalent of a *de jure* Account 800 transaction. Yet, a straightforward comparison of what the Federal Circuit actually *said* in Exxon I, concerning the definition of a wellhead sale, as opposed to what Exxon would like the Federal Circuit to have said in that regard, reveals the implausibility of Exxon's argument.

Wellhead Sale Non-Wellhead Sale

(Account 800) (Account 801)

Federal Circuit "[T]he *purchaser* transports "[T]he *producer* transports

De Jure the gas away from the the gas away from the

Definition *wellhead* . . . ." *wellhead*."[149]

Exxon "[T]he pipeline transport[s] "[T]he producer transport[s]

De Facto the gas from the producer's the gas off the *leased*

Definition *lease* to the pipeline's *premises* to the pipeline's

transmission system." transmission system."[150]

By hospitably substituting the term "lease" for the term "wellhead," in the Federal Circuit's definition of a "wellhead sale," Exxon would have this court adopt the gratuitous belief that the Federal Circuit views the wellhead and the lease to be one and the same. However, such an overly broad interpretation of the term "wellhead sale" obviously disregards any value added to the gas, prior to sale, if "the *producer* transports the gas away from the wellhead" to a delivery point located elsewhere within the lease. Exxon I, 88 F.3d at 977 (internal quotation omitted). Exxon I firmly instructs that such added value plays no role in the RMFP computation. Id. Thus, as in the Panhandle case, wherein the Court of Claims was faced with another taxpayer that sought to incorporate such added value into the RMFP, we find that Exxon's interpretation of the Federal Circuit's holding in Exxon I "would produce an indigestible result which we decline to swallow." Panhandle, 187 Ct. Cl. at 171, 408 F.2d at 716 (citing United States v. Henderson Clay Prods., 324 F.2d 7, 12 (5th Cir. 1963)).

Despite the lack of textual support for its position in the Federal Circuit's Exxon I opinion, Exxon nevertheless insists that the validity of its on-the-lease criterion was actually litigated and decided before the Federal Circuit in Exxon I. In support of this contention, Exxon directs our attention to the initial appellate brief it filed in Exxon I.[151] Therein, Exxon noted in passing that Mr. Ellis had categorized the 2,228 transactions in his 1974 RMFP study according to "whether the gas was delivered to the buyer on the producing lease (Account 800) or off lease at a field common point (Account 801)." Brief For Appellant at 38, Exxon I (CAFC No. 95-5116).[152]

However, the cited statement in Exxon's appellate brief employs descriptive rather than argumentative rhetoric. A bland narrative description of how Mr. Ellis went about preparing his 1974 RMFP study cannot objectively be viewed as argument intended to alert the Federal Circuit that the validity of Exxon's on-the-lease criterion was an issue actually in controversy. Exxon might as well argue that the meaning of each and every word that appeared in its appellate briefs, however innocuous, was somehow transmuted into a contested "issue" that was actually litigated before, and decided by, the Federal Circuit in Exxon I. We decline to read such neutral, descriptive text as argument. Moreover, Exxon did *not* argue that the Federal Circuit should adopt an on-the-lease/off-the-lease distinction in order to differentiate wellhead sales from non-wellhead sales. On the contrary, based upon the stated, albeit faulty, premise that the Court of Federal Claims had *already* adopted the on-the-lease criterion below, Exxon argued that the Federal Circuit should permit the inclusion of non-wellhead sales in the RMFP computation.(153)

Further, nothing in the appellate briefs that Exxon submitted in Exxon I was even remotely calculated to apprise the Federal Circuit of the argument that Exxon now makes, here at bar -- that the "lease," for purposes of Exxon's on-the-lease criterion, can be an aggregation of multiple common-law oil and gas leases, with no perceptible limitation upon the size of the acreage encompassed therein. Rather, in Exxon I, Exxon's initial appellate brief simply mentioned the term "lease" without any elaboration.(154) Lacking any signal that a specialized usage is intended, no reasonable person could assign the term "lease," in the context of a controversy involving natural gas production, anything other than its plain meaning, *i.e.*, a single common-law oil and gas lease. Thus, having failed to establish that the issue now presented -- the propriety of Exxon's unorthodox definition of the term "lease" -- is *identical* to an issue actually litigated before, and decided by, the Federal Circuit in Exxon I, Exxon cannot now assert that collateral estoppel bars the Government from litigating such issue in the case at bar. Arkla, 37 F.3d at 624.

In addition, we note that the Government's appellate brief in Exxon I never raised any distinction between on-the-lease transactions and off-the-lease transactions.(155) Consequently, our examination of the Exxon I appellate briefs leads us inexorably to the conclusion that the Federal Circuit never considered whether a *de facto* Account 800 transaction, designated as such by Mr. Ellis in accordance with Exxon's on-the-lease criterion, is the factual equivalent of a *de jure* Account 800 transaction, classified under the standard set out at 18 C.F.R. part 201, Account 800, and reported as such in a Form 2 annual report duly filed with the FPC. Exxon's written submissions regarding its collateral estoppel argument, here at bar, confirm our conclusion. For example, Exxon asserts that in the Exxon I appeal, "*neither party suggested any distinction* between the NARUC Account 800 *interstate* transactions and the Account 800 equivalent *intrastate* transactions. Therefore, the Federal Circuit had no occasion to 'expressly examine' a distinction between the two." Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 4 (emphasis added). In addition, Exxon declares:

It is important to remember that this case *is the first time* that Defendant . . . has sought to ascribe legal significance to the distinction between what this Court has characterized as 'de jure' and 'de facto' Account 800 sales. In Exxon I, *it was not suggested that otherwise identical intrastate and interstate sales would be treated differently* for purposes of computing the RMFP, just because interstate sales were reported to the FPC.

Plaintiff's Memorandum In Response To Defendant's Motion For Leave To Submit Appellate Briefs And Plaintiff's Exhibits Nos. 29 And 45 [from Exxon I], filed August 21, 1998, at 4 (emphasis added). We can scarcely conceive of a more unequivocal judicial admission than the foregoing, that the validity of Exxon's on-the-lease criterion was not actually litigated and decided in the Exxon I appeal.(156) Therefore, the Federal Circuit's decision in Exxon I does not preclude this court from considering that issue as a matter of first impression.

Exxon argues, further, that the Federal Circuit necessarily had to adopt Exxon's on-the-lease criterion in

Exxon I, inasmuch as the Court of Appeals computed the 1974 RMFP on the basis of 24 purported on-the-lease transactions.[(157)] See Exxon I, 88 F.3d at 979 & n.9. By this contention, Exxon invokes one of the indispensable elements of collateral estoppel -- that the resolution of a contested issue must have been "essential to a final judgment" in a prior action, in order to preclude the litigation of such issue in a subsequent action. Arkla, 37 F.3d at 624. In essence, using reverse logic to work its way back from the final judgment of the Federal Circuit in Exxon I, Exxon reasons that the Federal Circuit could not compute the 1974 RMFP on the basis of 24 on-the-lease transactions without having determined beforehand that such on-the-lease transactions qualify for inclusion in the RMFP computation, which in turn implies that the validity of Exxon's on-the-lease criterion was actually litigated and decided in Exxon I.

The Government responds to this argument, as noted above, with the contention that in Exxon I, the Federal Circuit was "duped" into computing the 1974 RMFP on the basis of 24 transactions that were presented in Mr. Ellis' 1974 RMFP study as *de jure* (interstate) Account 800 transactions when, in fact, 23 of those transactions were merely *de facto* (intrastate) Account 800 transactions.[(158)] Here at bar, notwithstanding Exxon's protests over the Government's version of what transpired in the Exxon I appellate proceedings, Exxon *admits* that 23 of the 24 transactions on which the Federal Circuit relied were, in fact, *de facto* Account 800 transactions, *i.e.*, *intra*state transactions never reported to the FPC under Account 800, Account 801, or otherwise, but merely determined by Mr. Ellis to be the factual equivalents of *de jure* Account 800 transactions.[(159)] However, even assuming, arguendo, that the Federal Circuit made a "mistake," as the Government puts it,[(160)] in relying upon the 24 transactions in question, we plainly cannot, and do not, sit in review of our senior court's judgment in Exxon I and pronounce error. "The court that considers the question of collateral estoppel does not examine the reasoning of the court that decided the issue," because "'[c]ollateral estoppel does not turn upon a determination that a prior ruling was *correctly* rendered . . . .'" Arkla, 37 F.3d at 626 (quoting Laaman v. United States, 973 F.2d 107, 112 (2d Cir. 1992) (emphasis in original), cert. denied, 507 U.S. 954 (1993)). Moreover, even further assuming that Exxon actually did what the Government contends, *supra*, the remedy for any such alleged malfeasance is not for this court to disregard the Federal Circuit's judgment in Exxon I. On the contrary, we agree with Exxon that the applicability of collateral estoppel, here at bar, must be determined in light of the Federal Circuit's actual holding in Exxon I, not the manner in which the 24 transactions in question were presented to the Federal Circuit.

Notwithstanding the foregoing, we disagree with Exxon's contention that a determination as to the validity of its on-the-lease criterion was essential to the Federal Circuit's judgment in Exxon I. We reach this conclusion for two reasons. First, Exxon's argument is logically unsound, for it rests on the assumption that a *de facto* Account 800 transaction, in which the delivery point is located anywhere on the producer's leased acreage dedicated to the contract in question, is the factual equivalent of a *de jure* Account 800 transaction. In a *de jure* Account 800 transaction, "the *purchaser* transports the gas away from the wellhead." Exxon I, 88 F.3d at 977. (emphasis in original, internal quotation omitted). For purposes of computing the RMFP, as explained above, the term "wellhead sale" includes a sale in which the point of delivery to the purchaser is located at the wellhead proper (*i.e.*, the "Christmas tree") or, more commonly, at the field separator appurtenant to that wellhead. Exxon I, 88 F.3d at 978; Panhandle, 187 Ct. Cl. at 151, 175, 227, 236, 408 F.2d at 704, 718. The wellhead and appurtenant separator are invariably located within the acreage covered by the producer's oil and gas lease(s), barring the improbable situation in which a trespassing producer situates its wellsite equipment on another's property. Therefore, every *de jure* Account 800 transaction is a sale "on the lease."

The converse, however, is *not* true. Not every sale "on the lease" qualifies as a *de jure* Account 800 transaction because, as Exxon concedes here at bar,[(161)] sales "on the lease" plainly include sales falling within the definition of a *de jure* Account 801 transaction, in which "the *producer* transports the gas away from the wellhead." Exxon I, 88 F.3d at 977 (emphasis in original, internal quotation omitted). Concomitantly, every sale "off the lease" is a *de jure* Account 801 transaction, inasmuch as the producer must transport the gas away from the wellhead to the off-the-lease delivery point, but not every *de jure* Account 801 transaction occurs "off the lease." Stated differently, Exxon's on-the-lease criterion defines *de facto* Account 801 transactions more narrowly (*i.e*., in less inclusive terms) than the Exxon I definition of a *de jure* Account 801 transaction. Likewise, Exxon's on-the-lease criterion defines *de facto* Account 800 transactions more broadly (*i.e*., in more inclusive terms) than the Exxon I definition of a *de jure* Account 800 transaction. Thus, Exxon's collateral estoppel argument, here at bar, rests entirely upon the fortuitous circumstance that every *de jure* Account 800 transaction, as narrowly defined in Exxon I, 88 F.3d at 977, also happens to fall within the broader category of sales "on the lease."

We reject this line of reasoning. In Exxon I, the Federal Circuit expressly approved a narrower definition of a *de jure* Account 800 transaction -- a sale in which "the *purchaser*," not the producer, "transports the gas away from the wellhead." Exxon I, 88 F.3d at 977 (emphasis in original). Consequently, having determined that a wellhead sale, so defined, qualifies for inclusion in the RMFP computation, the Federal Circuit had no need to consider whether a broader definition of a wellhead sale, *i.e*., Exxon's on-the-lease criterion, would also qualify. In other words, the Federal Circuit ultimately held that the 1974 RMFP could be computed on the basis of 24 transactions that, to all appearances, met its stated definition of a *de jure* Account 800 transaction. Exxon I, 88 F.3d at 979. Given the foregoing holding, it was *not* essential to the judgment that the Federal Circuit also determine whether a sale "on the lease" could likewise qualify for inclusion in the RMFP computation. Rather, even assuming, *arguendo*, that the validity of Exxon's on-the-lease criterion was raised in the Exxon I appeal -- a most improbable assumption, as the Federal Circuit's opinion and the parties' appellate briefs make clear -- any hypothetical disposition of that issue would have been merely "incidental or collateral," *i.e*., nonessential, to the Federal Circuit's actual final judgment. Mother's Restaurant, 723 F.2d at 1571. Accordingly, the doctrine of collateral estoppel does not preclude the Government from litigating the validity of Exxon's on-the-lease criterion in the case at bar. Id. See also Russell, 94 U.S. at 608, 610; Arkla, 37 F.2d at 624.

Turning to the second reason why a determination of the validity of Exxon's on-the-lease criterion was nonessential to the Federal Circuit's judgment in Exxon I, we are constrained to heed the Federal Circuit's express declaration that its computation of the 1974 RMFP was based upon 24 "FPC transactions" shown to be such by "the *undisputed* evidence of record." Exxon I, 88 F.3d at 979 (emphasis added). As noted above, in determining that the 24 transactions in question were undisputed, the Federal Circuit expressly relied upon the Panhandle presumption, under which it is rebuttably presumed that transactions reported under Account 800, in an interstate pipeline company's annual report (Form 2) filed with the FPC, are wellhead sales qualifying for inclusion in the RMFP computation. See Exxon I, 88 F.3d at 977 (explicating Panhandle presumption); id. at 979 (rejecting the Government's objection to the qualification of the aforesaid 24 transactions because "we presume that the FPC forms are representative of their underlying transactions"). In so doing, the Federal Circuit identified 24 "Account 800 sales," based upon their designation as such in Mr. Ellis' 1974 RMFP study. Id. at 978-79. Applying the Panhandle presumption, the Federal Circuit concluded that those 24 "Account 800 sales" were undisputed wellhead sales because "the government ha[d] made no showing of proof to rebut the [24] *FPC transactions* . . . ." Id. at 979 (emphasis added).(162)

Exxon now concedes, here at bar, that 23 of the aforementioned 24 transactions in Exxon I were not truly *de jure* "FPC transactions," as the Federal Circuit believed, but rather, *intra*state on-the-lease transactions never reported to the FPC under Account 800 or otherwise, *i.e*., *de facto* Account 800 transactions.(163) Yet, seeking now to capitalize upon the foregoing inconsistency, in essence, Exxon argues that the Federal Circuit's apparently inadvertent selection of 23 intrastate, on-the-lease transactions, for inclusion in the 1974 RMFP computation, precludes the Government from litigating the validity of Exxon's on-the-lease criterion in the present proceedings. We disagree. Because the 23 "FPC transactions" in question were selected on the basis of "the *undisputed* evidence of record," Exxon I, 88 F.3d at 979, it inescapably follows that it was unnecessary for the Federal Circuit to reach and decide the factual question presented in the case at bar -- whether a *de facto* Account 800 transaction is the factual equivalent of a *de jure* Account 800 transaction. Thus, inasmuch as the resolution of the foregoing factual question was *not* essential to the Federal Circuit's judgment in Exxon I, "the principle of issue preclusion is clearly inapplicable." Schendel v. Curtis, 83 F.3d 1399, 1405 (Fed. Cir. 1996).

Exxon evidently would have this court believe that in Exxon I, the Federal Circuit resolved the question of whether a sale, in which the purchaser transports the gas away from a delivery point located *anywhere* on the producer's "lease," expansively defined by Exxon to include an aggregation of multiple common-law oil and gas leases, with no perceptible limitation upon the acreage encompassed therein, is the factual equivalent of a sale in which the purchaser transports the gas away from the *wellhead*. Plainly, as noted above, the Court of Federal Claims had made no finding, as the trier of fact, to this effect in Exxon I, on which the Federal Circuit could rely. Therefore, at the core of Exxon's collateral estoppel argument, there lurks the disturbing contention that in Exxon I, the Federal Circuit tacitly engaged in what the Supreme Court has termed "impermissible appellate factfinding." Amadeo v. Zant, 486 U.S. 214, 228 (1988).[(164)]

Out of deference to our senior court, we are unable to accept the implausible notion that the Federal Circuit assumed the unorthodox role of appellate trier of fact in Exxon I. On the contrary, the Federal Circuit simply followed the settled rule that "[w]hen the pertinent facts are *undisputed*, as [in Exxon I], an appellate court need not remand for the trial court to make findings and conclusions but may resolve the issue." SmithKline Diagnostics, Inc. v. Helena Laboratories Corp., 859 F.2d 878, 891 (Fed. Cir. 1988) (emphasis added) (citing Icicle, 475 U.S. at 714; UMC Elecs. Co. v. United States, 816 F.2d 647, 657 (Fed.Cir.1987), cert. denied, 484 U.S. 1025 (1988)). Nothing in the Federal Circuit's Exxon I opinion even remotely suggests that the Court of Appeals weighed the evidence pertinent to the 23 on-the-lease intrastate transactions at issue, and determined that such transactions were the factual equivalents of *de jure* (interstate) Account 800 transactions.[(165)] Rather, the Federal Circuit selected those 23 transactions, as well as the single *de jure* Account 800 transaction presented by Exxon, on the basis of "the undisputed evidence of record." Exxon I, 88 F.3d at 979. In so doing, the Federal Circuit no doubt recognized that a remand to the trial court is required only if the resolution of a controverted issue of fact is "*essential* to a proper resolution" of the case. Icicle, 475 U.S. at 714. Thus, inasmuch as the Federal Circuit declined to remand the case for the computation of the 1974 RMFP, the purported factual equivalence of *de jure* and *de facto* Account 800 transactions was clearly an issue that was *non*essential to the judgment on appeal in Exxon I. Consequently, Exxon I does not preclude the Government from litigating the validity of Exxon's on-the-lease criterion in the case at bar. Russell, 94 U.S. at 608, 610; Schendel, 83 F.3d at 1405; Arkla, 37 F.2d at 624; Mother's Restaurant, 723 F.2d at 1571.[(166)]

To summarize all of the foregoing, we hold that Exxon has failed to demonstrate that the validity of its on-the-lease criterion was actually litigated, decided, and essential to the judgment in Exxon I. Therefore, we hold that the doctrine of collateral estoppel does not preclude the Government from litigating that issue in the case at bar. Given our disposition of Exxon's collateral estoppel argument, *supra*, we need not reach the Government's contention that collateral estoppel is inapplicable because the controlling statutory law changed between 1974 and 1975, due to the enactment of § 613A into law, effective January 1, 1975.[(167)] Accordingly, the discussion now turns to Exxon's contention that Treas. Reg. § 1.613-3(a) and the Court of Claims' Panhandle decision, 187 Ct. Cl. 129, 408 F.2d 690, furnish legal authority for the proposition that a sale of raw gas anywhere "on the lease" qualifies as a wellhead sale properly includible in the RMFP computation.

D. *Legal Foundations Of Plaintiff's On-The-Lease Criterion*

Seeking legal authority to sustain the validity of its on-the-lease criterion, Exxon argues that Treas. Reg. § 1.613-3(a) permits the inclusion of sales of raw gas anywhere "on the lease" in the RMFP computation. Exxon's regulatory interpretation rests upon two propositions. First, Exxon asserts that Treas. Reg. § 1.613-3(a) must be construed so as to assign "the immediate vicinity of the well" and "the premises" the same meaning. Second, Exxon maintains that a sale "on the premises," within the meaning of Treas. Reg. § 1.613-3(a), is equivalent to a sale "on the lease," as broadly defined by Exxon to include an aggregation of multiple, common-law oil and gas leases. The court agrees with the former proposition, but we firmly reject the latter.

Exxon correctly asserts that Treas. Reg. § 1.613-3(a) cannot be construed so as to create a regulatory "gap" between a sale "in the immediate vicinity of the well" and a sale "on the premises." This is so because Congress expressly directed that the computation of the depletion allowance is "*in all cases* to be made under regulations prescribed by the Secretary or his delegate." § 611(a) (emphasis added). In the case of natural gas production, the Secretary fulfilled that mandate with the promulgation of Treas. Reg. § 1.613-3(a). Exxon I, 88 F.3d at 980. Said regulation prescribes two alternative bases on which percentage depletion may be computed with respect to natural gas: (i) the actual sales price of the gas, if it is sold "in the immediate vicinity of the well"; or (ii) an RMFP, if "the gas is *not* sold *on the premises*," but instead is "transported from *the premises* prior to sale." Treas. Reg. § 1.613-3(a) (emphasis added). Again, we agree with Exxon that if the regulation were construed so as to give different meanings to the terms "the immediate vicinity of the well" and "the premises," a regulatory "gap" would result. So construed, Treas. Reg. § 1.613-3(a) would prescribe *no* method by which a producer that sold its gas beyond "the immediate vicinity of the well," but "on the premises," could compute its percentage depletion allowance, because in such case neither the actual sales price nor the RMFP method would be applicable. Such a regulatory "gap" would, therefore, cause Treas. Reg. § 1.613-3(a) to fail to comply with the congressional directive that regulations promulgated by the Secretary are to govern the computation of percentage depletion "in all cases." § 611(a).

Yet, while it is evident that we must construe Treas. Reg. § 1.613-3(a) so as to avoid a regulatory "gap," it does not logically follow, as Exxon urges, that "on the premises" inevitably means "on the lease." Exxon's singular and hospitable focus on the regulatory phrase "on the premises," at the expense of the preceding regulatory phrase, "in immediate vicinity of the well," imposes an untenable construction upon Treas. Reg. § 1.613-3(a), in clear contradiction to long established rules of construction. As fully explicated at an earlier stage of these proceedings, Treas. Reg. § 1.613-3(a) is legislative in character, having the force and effect of law, and must be construed in the manner of a statute. Exxon, 40 Fed. Cl. at 84-85, 90 (citing cases). "The cardinal principle of statutory construction is to save and not to destroy." National Labor Relations Board v. Jones & Laughlin Steel Corp., 301 U.S. 1, 30 (1937). Therefore, it is our duty to construe Treas. Reg. § 1.613-3(a) so as to give effect to its every term, and not to render one part altogether inoperative. See, e.g., Gustafson v. Alloyd Co., Inc., 513 U.S. 561, 574-75 (1995); Inhabitants of Montclair Tp. v. Ramsdell, 107 U.S. 147, 152 (1883); Forest v. Merit Sys. Protection Bd., 47 F.3d 409, 412 (Fed. Cir. 1995). With the foregoing principle in mind, we conclude that Exxon's interpretation of Treas. Reg. § 1.613-3(a), if sustained, would effectively render meaningless the operative regulatory phrase, "in the immediate vicinity of the well."

The significance of the interpretive question we must resolve, here at bar, pertains generally to the qualification of a sale of raw gas for inclusion in the RMFP computation and, specifically, to the distance over which the producer transports the gas away from the wellhead and to the point of delivery to the purchaser. Such transportation, if significant, is grounds for disqualifying the transaction from inclusion in the RMFP computation. Exxon I, 88 F.3d at 977. This is so because the inclusion of the value added by transportation in the RMFP would produce "a result that conflicts with" Treas. Reg. § 1.613-3(a).

Panhandle, 187 Ct. Cl. at 171-72, 408 F.2d at 716. Consequently, the requirement that the RMFP must exclude any material value added by transportation serves to *limit*, rather than expand, the number of raw gas sales in the relevant market area that are potentially includible in the RMFP computation.

Given the foregoing, in terms of delineating a tolerable distance between the wellhead and the physical location of the delivery point, we find the regulatory phrase "in the immediate vicinity of the well" somewhat more instructive than its counterpart, "on the premises." Because Treas. Reg. § 1.613-3(a), a legislative regulation, must be interpreted in the manner of a statute, we are guided by the canons of construction applicable to statutes. It is well settled that, in the absence of any evidence that a unique or specialized meaning is intended, the words of tax statutes should be construed "in their ordinary, everyday senses." Crane v. Commissioner, 331 U.S. 1, 6 (1947).[(168)] Upon applying the foregoing maxim to the regulatory phrase, "in the immediate vicinity of the well," the court is convinced that the manifest purpose of the adjective "immediate" is to limit the size of the physical area corresponding to the "vicinity of the well." We reach this conclusion because the term "immediate," in its ordinary, everyday sense, means "close at hand" or "near." *Webster's II -- New Riverside Dictionary* 611 (1988).[(169)] That Treas. Reg. § 1.613-3(a) makes reference to raw gas sold "in the *immediate* vicinity of the well" (emphasis added), as opposed to raw gas sold "anywhere in the general vicinity of the well," unmistakably implies a substantive limitation upon the distance between the wellhead and the delivery point.

Our construction of the regulatory phrase, "in the immediate vicinity of the well," accords not only with plain English, but also with the limiting principle, *supra*, that the RMFP must exclude any material value added to the gas, prior to sale, by transportation. As a matter of law, it is clear beyond cavil that Congress, in enacting the allowance for percentage depletion, intended that integrated natural gas producers, such as Exxon, "should not receive preferred treatment," relative to their "similarly situated" nonintegrated competitors. Hugoton II, 172 Ct. Cl. at 465, 349 F.2d at 431 (internal quotation omitted) (citing Cannelton, 364 U.S. 76). Therefore, "the fundamental goal of the [RMFP] calculation is to arrive at a price that is *representative* of the price which would be realized by nonintegrated producers." Exxon I, 88 F.3d at 976 (emphasis in original). In furtherance of such competitive parity, as between integrated and nonintegrated producers, the RMFP computation necessarily presumes that a typical nonintegrated producer sells its gas "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). See Exxon I, 88 F.3d at 970; 33 Fed. Cl. at 252. That is precisely why Treas. Reg. § 1.613-3(a) expressly draws the distinction between sales "in the immediate vicinity of the well" and all other sales made at all other locations more distantly removed from the well.

Under Treas. Reg. § 1.613-3(a), a natural gas producer that sells its gas in the immediate vicinity of the well must calculate its percentage depletion allowance upon the actual sales price of the gas, whereas a producer that sells its gas elsewhere, at some point further removed from the wellhead, must use the RMFP method. The RMFP of natural gas "is calculated as the weighted average price of wellhead sales of comparable gas in the taxpayer's market area." Exxon I, 88 F.3d at 976. In selecting sales of comparable gas for inclusion in the RMFP computation, the court must disregard transactions in which the gas is sold outside of the immediate vicinity of the well, because the gas producers in such transactions are *themselves* required to use the RMFP method. The *actual* sales price of the gas in any such transaction is, therefore, presumed to be tainted with value added by transportation. Basing Exxon's RMFP upon such tainted transactions would, of course, be contrary not only to Treas. Reg. § 1.613-3(a), but also to settled precedent. Panhandle, 187 Ct. Cl. at 171-72, 408 F.2d at 716. Given the foregoing, we conclude that the regulatory phrase, "in the immediate vicinity of the well," must be construed as a limitation that narrows the definition of a wellhead sale qualifying for inclusion in the RMFP computation.[(170)]

Conversely, with its on-the-lease criterion, Exxon would have us define a transaction that qualifies for inclusion in the RMFP computation broadly as a sale occurring at a delivery point located *anywhere* on the "lease," expansively defined by Exxon to include an aggregation of multiple common-law oil and gas leases, with no discernible limitation upon the acreage encompassed therein. Absent a probative and convincing demonstration that transportation "on the lease" adds no material value to natural gas, prior to sale,[(171)] we are constrained to conclude that Exxon's on-the-lease criterion is overinclusive, meaning that, in doubtful cases, it errs in the direction of including unqualified transactions. An overinclusive approach to selecting transactions for inclusion in the RMFP computation obviously tends to heighten the risk that the resultant RMFP will be tainted with value added by transportation. Thus, we must reject Exxon's invitation to blindly expand the definition of "the immediate vicinity of the well" to the outer boundaries of the producer's leased acreage, irrespective of the actual distances involved.

Further support for our conclusion is found in that canon of statutory construction known as *noscitur a sociis*,[(172)] "which holds that a word is known by the company it keeps." Babbitt v. Sweet Home Chapter of Communities for a Great Oregon, 515 U.S. 687, 694 (1995). See also Gustafson, 513 U.S. at 575; Neal v. Clark, 95 U.S. 704, 708-09 (1878). Stated differently, the meaning of an ambiguous or undefined term in a statute or regulation may be ascertained by reference to the meaning of other terms that accompany it. Sweet Home, 515 U.S. at 701; Jarecki v. G.D. Searle & Co., 367 U.S. 303, 307 (1961) (noting that a word "gathers meaning from the words around it"); Auto-Ordnance Corp. v. United States, 822 F.2d 1566, 1571 (Fed. Cir. 1987); 2A Norman J. Singer, *Sutherland's Statutory Construction* § 47.16 (5th ed. 1992). The doctrine of *noscitur a sociis* points out the flaw in Exxon's interpretation of Treas. Reg. § 1.613-3(a), which errs by construing the undefined phrase "on the premises" in isolation, totally deprived of the accompanying regulatory text that gives it meaning and context. As explained above, Treas. Reg. § 1.613-3(a) must be construed so that "the premises" are coterminous with the physical area delineated by "the immediate vicinity of the well." Since "the immediate vicinity of the well" and "the premises" are one and the same, elementary logic instructs that the term "immediate" *must* limit the physical scope of "the premises" no less than it does the "vicinity of the well."

In contrast, Exxon's liberal construction of the regulatory term "on the premises" disregards the restrictive tenor of its nearby synonym, "in the immediate vicinity of the well," and plainly violates the canon of *noscitur a sociis*. We cannot, therefore, accept an interpretation of Treas. Reg. § 1.613-3(a) that robs the regulatory phrase "in the immediate vicinity of the well" of all meaning, while imposing an overbroad meaning on the regulatory phrase "on the premises," so as to define a qualifying wellhead sale as a sale anywhere "on the lease." See Gustafson, 513 U.S. at 575 ("[W]e rely upon [the rule of *noscitur a sociis*] to avoid ascribing to one word a meaning so broad that it is inconsistent with its accompanying words, thus giving 'unintended breadth to the Acts of Congress.'") (quoting Jarecki, 367 U.S. at 307). Thus, we hold that Exxon's contention that its on-the-lease criterion is consistent with Treas. Reg. § 1.613-3(a) is legally without merit.

To the extent that the sale of raw gas "on the lease" has anything to do with a transaction's qualification for inclusion in the RMFP computation, we think the sounder view was expressed in the Panhandle case. Therein, the taxpayer was an interstate pipeline company that produced natural gas from 14 wells on oil and gas leases located in the Howell Field in Michigan. Panhandle, 187 Ct. Cl. at 133, 136-37, 161, 408 F.2d at 693, 696, 710.[(173)] The taxpayer transported all of the gas produced by 13 of its 14 wells, and a portion of the gas produced by its other well, the McPherson No. 1-35 well, away from the wellheads and off the leases, to a delivery point located 30 to 40 miles away. Id. at 162, 408 F.2d at 710-11. Due to its transportation of such gas, prior to sale, the taxpayer was required to compute its percentage depletion allowance on the basis of an RMFP, pursuant to the regulatory precursor to Treas. Reg. § 1.613-3(a). Id. at 163-64, 408 F.2d at 711. The remainder of the taxpayer's gas production from the McPherson No. 1-35 well was sold at a delivery point located "on the . . . McPherson lease near the wellhead." Id. at 162, 408 F.2d at 710.

In an intriguing turn of events, the Court of Claims found that for purposes of computing an RMFP, the *only* identifiable wellhead sale of comparable gas in the Howell Field was the taxpayer's *own* sale, involving that portion of the gas from the McPherson No. 1-35 well that was delivered on the McPherson lease and *near the wellhead*. Panhandle, 187 Ct. Cl. at 161, 167, 408 F.2d at 710, 713-14. Of critical importance, here at bar, in finding that such transaction qualified as a wellhead sale, the Panhandle court determined that the taxpayer sold the gas at a delivery point located "on the lease property *near the wellhead*." Panhandle, 187 Ct. Cl. at 137, 163, 172, 408 F.2d at 696, 711, 716 (emphasis added).(174) See also id. at 162, 408 F.2d at 710 ("The delivery point . . . was on the . . . lease near the wellhead."); id. at 172, 408 F.2d at 717 ("near the wellhead on the lease property"); id. at 175, 408 F.2d at 718 ("near the wellhead of plaintiff's McPherson No. 1-35 well" and, by necessary implication, on the aforementioned McPherson lease). The Panhandle definition of a wellhead sale, *supra*, embraces and gives effect to the regulatory phrase "in the immediate vicinity of the well," by requiring that such a sale take place "near the wellhead," without diminishing the import of the regulatory phrase "on the premises." Conversely, Exxon's on-the-lease criterion focuses exclusively on whether the sale is "on the premises," construed by Exxon to mean "on the lease," and treats the regulatory phrase "in the immediate vicinity of the well" as a nullity. Thus, Exxon's on-the-lease criterion is plainly at odds not only with Treas. Reg. § 1.613-3(a), but also with Panhandle's definition of a wellhead sale, *i.e*., a sale of raw gas "on the lease" *and* "near the wellhead." Panhandle, 187 Ct. Cl. at 137, 162, 163, 172, 175, 408 F.2d at 696, 710, 711, 716, 717, 718.

Exxon's citations to Panhandle, as precedential authority for the use of an on-the-lease/ off-the-lease distinction to differentiate between wellhead sales and non-wellhead sales, studiously avoid the statements in the Panhandle opinion on which we rely, *supra*. Instead, Exxon prefers various language in the Panhandle opinion that is seemingly more hospitable to its on-the-lease criterion. For example, Exxon calls our attention to the fact that the Court of Claims' observation that, in order to compute an RMFP with respect to the taxpayer's gas production in the Hugoton Embayment, it was necessary to select a market "area in the Embayment . . . from which wellhead *or* on-the-lease sales can be ascertained." Panhandle, 187 Ct. Cl. at 148, 408 F.2d at 703 (emphasis added). Similarly, Exxon points out that, relative to the taxpayer's gas production in the Howell Field in Michigan, the Court of Claims noted: "The Howell Field situation is unique in that one on-the-lease property *or* wellhead sale of gas is involved . . . ." Panhandle, 187 Ct. Cl. at 161, 408 F.2d at 710 (emphasis added). Apparently, because the Court of Claims twice referred to "wellhead" sales or "on-the-lease" sales, in the disjunctive, *supra*, Exxon believes that Panhandle stands for the proposition that a transaction qualifying for inclusion in the RMFP computation may be *either* a sale at the wellhead sale *or* a sale *anywhere* "on the lease." Exxon's self-serving interpretation of Panhandle fails to hold up on closer examination, however.

Neither of the cited statements in the Panhandle opinion purport to be what Exxon would like them to be -- a definitive *holding* that every sale "on the lease," *ipso facto*, qualifies for inclusion in the RMFP computation. The Court of Claims' reference to "wellhead or on-the-lease sales" was made in conjunction with the definition of the relevant market area, relative to the taxpayer's gas production in the Hugoton Embayment, not the definition of a qualifying wellhead sale. Panhandle, 187 Ct. Cl. at 148, 408 F.2d at 703. Inasmuch as the "main thrust" of the court's analysis of the Hugoton Embayment issue related to the definition of the relevant market area, 187 Ct. Cl. at 153, 408 F.2d at 705, we are skeptical that the definition of a qualifying wellhead sale is best sought in that section of the Panhandle opinion.

Moreover, with only two minor exceptions, the Panhandle court was not called upon to make factual findings regarding the qualification of the Hugoton Embayment transactions that were included in the taxpayer's RMFP computation.(175) As to the only two contested transactions in the Hugoton Embayment, the Court of Claims found that "gas purchased by [the] plaintiff *at the wellhead*" had been "erroneously listed as non-wellhead sales in the gas purchase sections of plaintiff's [FPC] Forms 2." Panhandle, 187 Ct. Cl. at 151, 408 F.2d at 704 (emphasis added). Without mentioning whether the aforesaid two transactions were sales "on the lease," the Panhandle court approved their inclusion in the taxpayer's Hugoton Embayment RMFP computation. Id. at 151-52, 408 F.2d at 704-05. Given the Court of Claims' only stated rationale for the foregoing holding -- that the gas was sold "at the wellhead" -- Exxon's contention that its on-the-lease criterion was approved in the Panhandle case, in conjunction with the Hugoton Embayment controversy, is simply incomprehensible. Thus, Exxon errs in construing the Panhandle court's passing reference to "wellhead or on-the-lease sales," 187 Ct. Cl. at 148, 408 F.2d at 703, in the context of the Hugoton Embayment controversy, as a definitive holding that every sale "on the lease" qualifies for inclusion in the RMFP computation.

In Panhandle, the definition of a qualifying wellhead sale was more squarely presented in connection with the dispute over the taxpayer's gas production in the Howell Field in Michigan. Exxon puts great emphasis upon the Court of Claims' introductory statement: "The Howell Field situation is unique in that one on-the-lease property *or* wellhead sale of gas is involved . . . ." Panhandle, 187 Ct. Cl. at 161, 408 F.2d at 710 (emphasis added). We are not convinced, however, that such an introductory statement can be plausibly read as a *holding*, to the effect that a transaction qualifying for inclusion in the RMFP computation may be *either* a sale at the wellhead sale *or* a sale *anywhere* "on the lease." What is more, the Panhandle court's discussion of the Howell Field controversy describes a qualifying wellhead sale, no fewer than *six times*, as a transaction in which the delivery point is *both* on the lease *and* near the wellhead.[(176)] See Panhandle, 187 Ct. Cl. at 137, 408 F.2d at 696 ("on the lease property near the wellhead"); 187 Ct. Cl. at 162, 408 F.2d at 710 ("on the . . . lease near the wellhead."); 187 Ct. Cl. at 163, 408 F.2d at 711 ("on the lease property near the wellhead"); 187 Ct. Cl. at 172, 408 F.2d at 716 ("on the lease property near the wellhead"); 187 Ct. Cl. at 172, 408 F.2d at 717 ("near the wellhead on the lease property"); 187 Ct. Cl. at 175, 408 F.2d at 718 ("near the wellhead" and, by necessary implication, on the related lease). Therefore, Exxon's claim that in Panhandle, the Court of Claims construed Treas. Reg. § 1.613-3(a) to define a qualifying wellhead sale as a sale *anywhere* "on the lease," simply ignores the plain language of the Panhandle opinion.

Conversely, reading Panhandle faithfully, as we do, to define a qualifying wellhead sale as a sale on the lease *and* near the wellhead, results in a sounder, more consistent construction not only of Treas. Reg. § 1.613-3(a), as noted above, but also of the Panhandle opinion itself. Further, our reading of Panhandle's definition of a wellhead sale is in accord with other natural gas RMFP precedents. See Exxon I, 88 F.3d at 977 (defining a *de jure* Account 800 transaction, *i.e*., a wellhead sale, as a sale in which "the *purchaser* transports the gas away from the wellhead" (emphasis in original)); Shamrock, 35 T.C. at 989 ("A wellhead sale of gas is a sale where the purchaser lays a line to receive the gas *at the wellhead on the lease*." (emphasis added)). In contrast, Exxon's hospitable interpretation of Panhandle is irreconcilable with the wellhead sale definitions adopted in the Exxon I and Shamrock cases.[(177)]

Exxon also cites the holding in Panhandle, relative to the Howell Field controversy, that the taxpayer was not entitled to base its percentage depletion allowance upon an RMFP calculated with reference to the sale price of the gas "after it was gathered, transported, and delivered some distance *away from the lease* property." Panhandle, 187 Ct. Cl. at 172, 408 F.2d at 716 (emphasis added). The principle that Exxon apparently seeks to extract, in a herculean leap of logic, from the foregoing and several statements to similar effect in the Panhandle opinion, is that because off-the-lease sales fail to qualify as wellhead sales, properly includible in the RMFP computation, every sale "on the lease," without more, must so qualify. We have, of course, already addressed the logical fallacy manifest in this argument. As previously observed, barring exceptional circumstances, it is no doubt the case that every wellhead sale is a sale "on the lease," but that does not mean that every sale on the "lease," as broadly defined by Exxon, satisfies the requirement that the gas be sold "in the immediate vicinity of the well," Treas. Reg. § 1.613-3(a), or "near the wellhead." Panhandle, 187 Ct. Cl. at 137, 162, 163, 172, 408 F.2d at 696, 710, 711, 716, 717, 718. Concomitantly, merely because every sale "off the lease" is deemed to occur after the gas has been transported away from the wellhead, as in Panhandle (or any other circumstances), it does not logically follow that every sale on the "lease," as Exxon employs that term, qualifies for inclusion in the RMFP computation.

The fundamental flaw in Exxon's *stare decisis* argument is that the "lease," expansively defined by Exxon, fails to square with the ordinary meaning of the term "lease" known to the Court of Claims in the Panhandle decision. Here at bar, as noted above, Exxon defines the "lease" to include an aggregation of multiple common-law oil and gas leases, the gas production from which is dedicated to a gas purchase contract, with no limitation upon the total size of the acreage encompassed therein. So long as the point of delivery to the purchaser falls *anywhere* "on the lease," *i.e.*, within any one of the multiple leases dedicated to the gas purchase contract in question, Exxon contends that the transaction qualifies for inclusion in the RMFP computation. However, nothing in the Panhandle opinion suggests that the Court of Claims considered, let alone accepted, the overbroad "lease" definition that Exxon advocates here.

In Panhandle, as explicated above, the taxpayer produced gas from 14 wells situated on multiple leases in the Howell Field. Panhandle, 187 Ct. Cl. at 161, 408 F.2d at 710 ("Plaintiff owned, as lessee, an economic interest in oil and gas *leases* . . . [in] the Howell Field." (emphasis added)). Although the Panhandle opinion does not expressly find that the contract under which the taxpayer sold its gas contained a dedication clause, one can readily deduce the existence of such a contractual dedication, given that the taxpayer sold all of its Howell Field gas production to a single purchaser under a single contract. Id. at 162, 408 F.2d at 710. Thus, under Exxon's definition, all of the Panhandle taxpayer's leased acreage in the Howell Field constituted a single combined "lease." Yet, the Court of Claims plainly did not view the taxpayer's multiple Howell Field leases, dedicated to a single contract, as a single, amalgamated lease.

On the contrary, with respect to the majority of the taxpayer's Howell Field gas production, the Panhandle court expressly held that the taxpayer was not entitled to base its percentage depletion allowance upon the actual sale price of the gas, because the gas had been "sold off the *leases* . . . and transported from the *leases*." Panhandle, 187 Ct. Cl. at 162, 408 F.2d at 711 (emphasis added).(178) Further, the Court of Claims held that the sale price of the gas had to be reduced by "the stipulated cost of 3 ½¢ per MCF to [the taxpayer] of *gathering the gas from its wells* and transporting it off the *leases* to the delivery points." Id. at 175, 408 F.2d at 718 (emphasis added).(179) The fundamental significance of the holding in Panhandle, *supra*, is that Exxon's overbroad definition of the "lease," as noted above, has the effect of disregarding any gathering of the gas from multiple wells situated on multiple common-law oil and gas leases. Had the Panhandle court viewed the taxpayer's Howell Field leases as a single combined "lease," in accordance with Exxon's view, the court would have been unconcerned about all of the costs the taxpayer incurred in "gathering the gas from its wells *and* transporting it off the leases to the delivery points." Id. at 175, 408 F.2d at 718 (emphasis added). Rather, only the costs associated with "transporting [the gas] off the leases to the delivery points," *supra*, would have been relevant. Thus, in Panhandle, the Court of Claims clearly viewed the taxpayer's leased acreage in the Howell Field in terms of the individual leases therein, not as a single, combined "lease" of the sort that Exxon warmly advocates, here at bar.(180)

Given all of the foregoing, the court holds that neither Treas. Reg. § 1.613-3(a), nor the Panhandle decision, 187 Ct. Cl. 129, 408 F.2d 690, furnish legal authority for Exxon's argument that a sale of raw gas anywhere "on the lease" qualifies for inclusion in the RMFP computation. Having also considered certain lesser authorities cited by Exxon, we find them likewise unhelpful to Exxon's cause.(181)

Therefore, in order for Exxon to ultimately prevail on its contention that all such on-the-lease sales are, *ipso facto*, eligible for inclusion in the RMFP computation, the record must contain affirmative proof that a sale "on the lease" is, in every case, a sale "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). As noted above, in an abortive effort to carry its burden, Exxon makes two factual allegations. First, Exxon contends that in 1975, interstate pipeline companies categorized their gas purchases under NARUC Accounts 800 or 801, in their FPC annual reports (Forms 2), in accordance with an on-the-lease/ off-the-lease distinction, with the endorsement of the FPC. Second, regardless of whether its on-the-lease criterion was rooted in industry and regulatory practice in 1975, Exxon maintains that the transportation of natural gas "on the lease," prior to sale, adds no material value to the gas. We address the merits of the foregoing two allegations below, *seriatim*.

E. *Evidentiary Foundations Of Plaintiff's On-The-Lease Criterion*

As discussed above, a *de jure* Account 800 transaction is a gas purchase designated as such by an interstate pipeline in a 1975 annual report (Form 2) duly filed with the FPC. Under the Panhandle presumption, for purposes of the RMFP computation, a *de jure* Account 800 transaction is rebuttably presumed to be a wellhead sale, in which "the *purchaser* transports the gas away from the wellhead." Exxon I, 88 F.3d at 977 (emphasis in original); Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05. Citing industry and regulatory practice in 1975, Exxon argues, in essence, that the Panhandle presumption should be extended to embrace all transactions that satisfy its on-the-lease criterion, *i.e.*, a sale of gas anywhere on the "lease," broadly defined by Exxon to include an aggregation of multiple common-law oil and gas leases dedicated to a gas purchase contract, without limitation upon the acreage encompassed therein.(182) In other words, as discussed herein, *supra*, Exxon's basic contention is that a *de facto* (*i.e.*, on-the-lease) Account 800 transaction is the factual equivalent of a *de jure* Account 800 transaction.

Exxon's on-the-lease criterion is the apparent brainchild of Mr. Ellis, who also used this standard to identify the purported wellhead sales designated as *de facto* Account 800 transactions in the 1974 RMFP study he submitted in Exxon I. Here at bar, Mr. Ellis testified that he examined the contract files underlying the *de jure* Account 800 transactions in issue, in order to determine how interstate pipeline companies drew the distinction between wellhead (Account 800) and field line (Account 801) gas purchases in 1975, for purposes of their Form 2 annual report filings with the FPC. In Mr. Ellis' opinion, the "common element" of the *de jure* Account 800 transactions he examined was a delivery point located somewhere within the producer's leased acreage that was dedicated to the contract. Tr. 929. However, Mr. Ellis was unable to trace his on-the-lease criterion to any FPC publication or authoritative natural gas industry literature.(183) Mr. Ellis admitted, further, that he had not contacted any of the interstate pipeline companies that did business in the Texas Gulf Coast/East Texas region in 1975, in order to ask such pipeline companies how they drew the distinction, in their FPC filings, between Account 800 wellhead purchases and Account 801 field line purchases.(184) Consequently, Mr. Ellis' unsubstantiated opinion testimony fails to persuade the court that interstate pipeline companies did, in fact, use an on-the-lease/off-the-lease distinction to categorize their gas purchases under Accounts 800 and 801 in their 1975 Form 2 annual report filings with the FPC.(185)

Ironically, Exxon called another witness who presumably could have testified from firsthand experience regarding such matters -- Mr. Hague, who was responsible for negotiating and administering the gas purchase contracts of a major interstate pipeline company, United Gas Pipe Line Company, in 1975. Yet, Exxon failed to ask Mr. Hague whether United utilized an on-the-lease criterion to distinguish between Account 800 and Account 801 transactions. From Exxon's omission, we can reasonably infer the contrary. See Day & Zimmerman Services v. United States, 38 Fed. Cl. 591, 602 n.13 (1997). Indeed, on cross-examination, Mr. Hague testified that United classified its gas purchases in accordance with the *de jure* Account 800 and Account 801 standards published by the FPC in 18 C.F.R. part 201.(186) Thus, on this record, the only assurance we have that interstate pipeline companies used an on-the-lease/off-the-lease distinction to categorize their gas purchases under Accounts 800 and 801, in their 1975 FPC filings, is Mr. Ellis' naked, uncorroborated opinion to this effect.

Our conclusion that Exxon has failed to prove that interstate pipeline companies used an on-the-lease/off-the-lease distinction in 1975, in order to differentiate between wellhead and non-wellhead gas purchases, applies with equal force to the Texas *intra*state pipeline companies. As noted above, the Texas Railroad Commission did not require intrastate pipeline companies to use the NARUC Uniform System of Accounts in their GUD annual report filings until 1977. However, Exxon asserts that, when the usage of NARUC Accounts 800 and 801 in GUD reports became mandatory in 1977, the Texas intrastate pipelines utilized an on-the-lease/off-the-lease distinction in order to categorize their gas purchases under Account 800 or Account 801.(187) Exxon maintains, further, that by reviewing such 1977-1979 GUD reports, Mr. Ellis was able to retroactively confirm the validity of the judgments he made, using Exxon's on-the-lease criterion, in identifying purported intrastate wellhead sales (*i.e.*, *de facto* Account 800 transactions) that occurred in 1975.

On this record, we find the foregoing argument wholly unconvincing. Once again, as with Exxon's assertions regarding the 1975 reporting practices of the interstate pipeline companies, *supra*, Exxon's contention that its on-the-lease criterion was adopted by the Texas intrastate pipeline companies, in their 1977-1979 GUD annual reports, depends totally upon Mr. Ellis' uncorroborated opinion to this effect. Moreover, Exxon has failed to demonstrate that 1977-1979 GUD reports are a reliable source of *post hoc* confirmation of the validity of the judgments Mr. Ellis made in classifying 1975 intrastate gas purchases as *de facto* (on-the-lease) Account 800 transactions, or *de facto* (off-the-lease) Account 801 transactions. Upon examining a substantial number of the intrastate pipeline company gas purchase contract files in evidence (PX 14a and PX 14b), the court found that with respect to any given transaction, the number and physical location of the delivery point(s), relative to the producer's wellhead(s), can change over time as a result of any number of events. Such events include, but are not limited to: (i) new wells being drilled and commencing production; (ii) old wells depleting and ceasing production; or (iii) the producer's installation of centrally-located compression facilities to compensate for the depletion of the natural pressure of the gas in the underlying reservoir(s). Consequently, GUD reports for the years 1977-1979 fail to reliably establish whether a 1975 transaction was a wellhead sale or a non-wellhead sale, unless it is first shown that there was no change in the delivery point(s) between the year 1975 and the 1977-1979 time frame. Exxon has not even attempted to make such a probative showing. Further, the court is unable, on this record, to verify which of the many thousands of transactions listed in the 1977-1979 GUD reports correspond to the 1,080 intrastate transactions listed in Mr. Ellis' 1975 RMFP study.(188)

Given the foregoing, on this record, the court is constrained to conclude that Exxon has not proven that its on-the-lease criterion was utilized by any of the Texas intrastate pipeline companies during the 1970s, including the year 1975. Therefore, we hold that Exxon has failed to establish that, as of 1975, either segment of the natural gas pipeline industry -- interstate or intrastate -- routinely and systematically utilized an on-the-lease/off-the-lease distinction in order to differentiate between wellhead purchases of raw gas and non-wellhead purchases.

What is more, Exxon has failed to demonstrate that its on-the-lease criterion is consistent with the rules and regulatory practices of the FPC in 1975. The regulatory definitions of a Account 800 wellhead purchase and an Account 801 field line purchase, set out in 18 C.F.R. part 201, do not even mention the word "lease."(189) However, the regulatory definition of an Account 801 transaction does include gas purchases "at *points along gathering lines*, . . . where *facilities of the vendor* or others are used in bringing the gas from the well head to the point of entry into the utility's natural gas system." 18 C.F.R. part 201, Account 801 ¶ A (1975) (emphasis added). We read the foregoing reference to "gathering lines" to include gathering lines that a producer (*i.e.*, the "vendor" under Account 801) uses to transport gas away from the wellhead, prior to sale, to a delivery point located elsewhere on the producer's leased acreage. Thus, transactions that satisfy Exxon's on-the-lease criterion clearly can fall within the regulatory definition of a *de jure* Account 801 transaction, wherein "the *producer* transports the gas away from the wellhead." Exxon I, 88 F.3d at 977 (emphasis in original). *De jure* Account 801 transactions fail to qualify as wellhead sales for purposes of the RMFP computation. Id. Of course, a transaction that satisfies Exxon's on-the-lease criterion may also fall within the regulatory definition of a *de jure* Account 800 transaction, and thereby qualify as a wellhead sale for purposes of the RMFP computation, but only upon proof that "the *purchaser* transport[ed] the gas away from the wellhead." Id. (emphasis in original). Thus, inasmuch as a sale of raw gas "on the lease," without more, can fall within the literal definition of either a *de jure* Account 800 transaction, *or* a *de jure* Account 801 transaction, Exxon's on-the-lease criterion plainly fails to reflect the regulatory distinction between Accounts 800 and 801 that was enunciated in Exxon I.

That a delivery point "on the lease" has nothing to do with the regulatory definition of an Account 800 transaction was underscored at trial by the testimony of Mr. Edmonds, the deputy director of the Office of Pipeline Regulation of the Federal Energy Regulatory Commission (FERC), the successor agency to the FPC. Mr. Edmonds' experience with the NARUC Uniform System of Accounts, 18 C.F.R. part 201, in connection with the FPC's (and later, FERC's) regulatory oversight of interstate pipeline companies, dates to the early 1970s and includes the year 1975. In the 1970s, Mr. Edmonds explained, the FPC used the NARUC Account 800 series of accounts (*i.e.*, Accounts 800, 801, 802, etc.) in order to locate and quantify gas purchases by interstate pipeline companies. Specifically, for purposes of regulating the prices that interstate pipeline companies were allowed to pay and charge for gas, the distinction between Accounts 800 and 801 determined whether the gas producer was entitled to a gathering allowance. If the gas was delivered into the interstate pipeline's system at the end of a producer's gathering line, the pipeline company was allowed to pay the producer the wellhead price set by the FPC, plus an additional gathering allowance. Conversely, if the interstate pipeline company owned the gathering line through which the gas was transported away from the wellhead, no gathering allowance was payable to the producer.

Mr. Edmonds opined that, from the viewpoint of the FPC staff in the 1970s, the on-the-lease/off-the-lease distinction had nothing to do with whether an interstate pipeline company was required to classify a gas purchase under Account 800 or Account 801. Rather, the regulatory distinction between Accounts 800 and 801 turned upon the ownership of the pipeline facilities that transported the gas away from the wellhead. Account 800, in Mr. Edmonds' opinion, describes a transaction in which the interstate pipeline company owns the pipeline facilities that pick up the gas at or near the producer's wellhead. On the other hand, he opined, Account 801 describes a transaction in which the interstate pipeline company's facilities only run through a producing field, or extend to a central point in the producing field, such that the gas producer is required to transport the gas away from the wellhead in order to deliver such gas to the pipeline company. In short, Mr. Edmonds' views concerning the regulatory distinction between Accounts 800 and 801 mirror the distinction drawn in Exxon I, 33 Fed. Cl. at 273 ("The distinction is that in Account 800 sales the *purchaser* transports the gas away from the wellhead; whereas in Account 801 sales, the *producer* transports the gas away from the wellhead.") (emphasis in original), quoted with approval, 88 F.3d at 977.

Exxon argues that Mr. Edmonds' view of the regulatory distinction between Accounts 800 and 801 is contradicted by the official position of FERC and, formerly, the FPC, on this matter. In support thereof, Exxon cites the following pronouncement by FERC:

In Order Nos. 94 and 94-A, the Commission removed the requirement that a producer provide *some off-lease delivery* as a qualification for the area-wide gathering allowances under the Natural Gas Act. Previously, the Commission had required that, in order to qualify for the allowance, the seller first had to expend money for substantial *off-lease gathering* from at least two wells.

Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978, 48 Fed. Reg. 44495, 44497-44498 (Sep. 27, 1983) (emphasis added). Exxon construes the foregoing statement to mean that, prior to the issuance of FERC Orders Nos. 94 and 94-A, including the year 1975, the longstanding official position of FERC and its precursor, the FPC, was that gathering allowances were payable *only* when the producer performed off-the-lease gathering. Given Mr. Edmonds' testimony, *supra*, that interstate pipeline companies were allowed to pay gathering allowances to gas producers in Account 801 transactions, but not Account 800 transactions, Exxon concludes that transactions with off-the-lease delivery points had to fall under Account 801, whereas transactions with on-the-lease delivery points necessarily fell under Account 800.

The court disagrees. Exxon cites FERC's statement regarding its Orders Nos. 94 and 94-A, *supra*, completely out of its proper historical context. FERC's policy of limiting the payment of gathering allowances to producers that performed off-the-lease gathering was a regulatory aberration of sorts, adopted in 1978 but withdrawn in 1980,[190] that had no evident relationship to the FPC's interpretation and application of NARUC Accounts 800 and 801 in the year 1975. In fact, as of 1975, the FPC drew no distinction whatsoever between on-the-lease gathering and off-the-lease gathering, in determining whether gathering allowances were payable to gas producers in the Texas Gulf Coast/East Texas region. See Opinion No. 595, Texas Gulf Coast Area Rate Proceeding, 45 F.P.C. 674, *passim* (1971), modified, Opinion No. 595-A, 46 F.P.C. 827 (1971), vacated and remanded sub nom. Public Service Comm'n of New York v. FPC, 487 F.2d 1043 (D.C. Cir. 1973), vacated and remanded, 417 U.S. 964 (1974), on remand, 516 F.2d 746 (D.C. Cir. 1975) (affirming FPC Opinion No. 595, *supra*), codified at 18 C.F.R. § 154.111 (1971) (establishing Texas Gulf Coast pricing, effective August 1, 1971 through December 31, 1975); Opinion No. 607, Other Southwest Area Rate Proceeding, 46 F.P.C. 900, *passim* (1971), modified, Opinion No. 607-A, 47 F.P.C. 99 (1971), aff'd sub nom. Shell Oil Co. v. FPC, 484 F.2d 469 (5th Cir. 1973), cert. denied, 417 U.S. 973 (1974), codified at 18 C.F.R. § 154.109a (1971) (establishing East Texas pricing, effective January 1, 1972 through June 30, 1976). Further, as to the circumstances in which a gas producer was entitled to a gathering allowance, as of 1975, the aforementioned FPC pronouncements are substantially in accord with Mr. Edmonds' views, *supra*, regarding the distinction between Accounts 800 and 801. Thus, Exxon has failed to demonstrate that its on-the-lease criterion has any plausible connection with the regulatory practices of the FPC, from the standpoint of how that agency interpreted and applied Accounts 800 and 801 in 1975.

Independent of its meritless contention that Accounts 800 and 801 reflect an on-the-lease/ off-the-lease distinction, Exxon also contends that its on-the-lease criterion was widely used in natural gas contracts in 1975. Specifically, revisiting the text of Treas. Reg. § 1.613-3(a), Exxon argues that the regulatory phrase "immediate vicinity of the well" is not used in natural gas contracting, whereas the regulatory phrase "on the premises" is commonly used to denote a wellhead sale. According to Exxon, most royalty clauses in oil and gas lease agreements reflect this conception of a wellhead sale, with "the premises" understood to mean the boundaries of "the lease." As evidence of such industry usage, Exxon cites Exxon Corp. v. Middleton, 613 S.W.2d 240 (Tex. 1981), a case arising from a natural gas royalty dispute. In Middleton, the Texas Supreme Court held that in construing a royalty clause in a natural gas lease agreement under Texas law, "sold 'off the premises' means gas which is sold outside the leased premises [and]

. . . 'sold at the wells' means sold at the wells within the lease and not sold at the wells within the fields." Id. at 243.

However, Exxon's hospitable citation to the Texas Supreme Court's Middleton decision disregards the fact that Middleton addresses the meaning of "the premises" solely in connection with state-law doctrines concerning the interpretation of royalty clauses in oil and gas leases. Consequently, as a matter of law, respecting the issues at bar, Middleton does not, and cannot, establish that a sale "on the lease" is a wellhead sale qualifying for inclusion in the RMFP computation under Treas. Reg. § 1.613-3(a). State law doctrines that establish the price or value on which natural gas royalties are payable, such as the Middleton decision, have never governed, and can never govern, the calculation of an integrated natural gas producer's gross income from the property for purposes of computing the percentage depletion deduction allowable under federal income tax law. See Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718; Shamrock, 35 T.C. at 1035.(191) Therefore, were this court to approve Exxon's on-the-lease criterion, here at bar, in reliance upon Middleton, as an acceptable method of identifying wellhead sales for purposes of the RMFP computation, we would improperly permit Exxon to compute its 1975 percentage "depletion allowance based on a royalty pricing approach which the courts have determined to be unacceptable." Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718. Accordingly, relative to the asserted validity of Exxon's on-the-lease criterion, for purposes of the RMFP computation, we hold that Middleton is simply inapposite.

Given the foregoing, we also hold that Exxon has failed to prove that a *de facto* Account 800 transaction, in which raw gas is sold at a delivery point located *anywhere* on the "lease," as broadly defined by Exxon, is the factual equivalent of a *de jure* Account 800 transaction, in which "the *purchaser* transports the gas away from the wellhead." Exxon I, 33 Fed. Cl. at 273 (emphasis in original), quoted with approval, 88 F.3d at 977. Notwithstanding its utter failure to marshal credible evidence in support of its position, Exxon strongly protests that in Exxon I, "it was not suggested that *otherwise identical* intrastate and interstate sales would be *treated differently* for purposes of computing the RMFP, just because interstate sales were reported to the FPC."(192) For the sake of completeness, the court believes this contention cannot go without response. It is no doubt correct, as Exxon urges, that "otherwise identical" interstate and intrastate transactions should not be "treated differently" *solely* because the former are reported under Account 800 to the FPC and the latter are not. Yet, Exxon assigns far more significance to this truism than it can logically bear.

The point to be kept in mind is that an interstate transaction reported to the FPC under Account 800 is rebuttably presumed to be a sale of raw gas made in the immediate vicinity of the well, within the meaning of Treas. Reg. § 1.613-3(a). Exxon I, 88 F.3d at 977 (emphasis in original); Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05. Conversely, an *intra*state transaction that was never reported to the FPC, but merely classified as a *de facto* Account 800 transaction in Mr. Ellis' RMFP study, by virtue of his subjective judgment that such transaction satisfies Exxon's on-the-lease criterion, is entitled to no such presumption of correctness. But it does not automatically follow that a *de facto* (intrastate) Account 800 transaction must be "treated differently," as Exxon puts it, than a *de jure* (interstate) Account 800 transaction. On the contrary, the aforementioned distinction implies only that Exxon has the burden of proving, by a preponderance of the evidence, that Mr. Ellis' *de facto* Account 800 transactions are, in fact, the equivalent of *de jure* Account 800 transactions in all material respects. Should Exxon carry its required burden, Mr. Ellis' *de facto* Account 800 transactions are entitled to be treated as "otherwise identical" to *de jure* Account 800 transactions. If, on the other hand, Exxon fails to carry its burden, then its *de facto* Account 800 transactions shall be "treated differently" to the extent necessary to make certain that the RMFP calculation does not produce a distorted result, *i.e.*, an RMFP which cannot be fairly viewed as representative of the market price of comparable raw gas sold at the wellhead in the relevant market area.

Here at bar, for the reasons noted above, we hold that Exxon has totally failed to demonstrate that, in terms of industry and regulatory practice in 1975, a *de facto* Account 800 transaction was the factual equivalent of a *de jure* Account 800 transaction, *i.e.*, a transaction in which "the *purchaser* transports the gas away from the wellhead." Exxon I, 88 F.3d at 977 (emphasis in original). However, this does not end our inquiry regarding the effect that transportation of the gas, prior to sale, has upon the qualification of a transaction for inclusion in the RMFP computation, for we have yet to consider Exxon's final contention -- that the act of transporting natural gas away from the wellhead, to a delivery point located *anywhere* "on the lease," adds no material value to such gas. As discussed below, Exxon's argument not only runs contrary to precedent, but also lacks probative evidentiary support in the record.

F. *Transportation,"On The Lease" Or Not, Adds Value To Natural Gas*

Exxon's on-the-lease criterion, as noted above, hospitably presumes that a natural gas producer adds no material value to the gas by transporting, or gathering, it away from the wellhead, prior to sale, to a delivery point located *anywhere* within the boundaries of the "lease." For this purpose, Exxon broadly defines a "lease" to include an aggregation of multiple common-law oil and gas leases that were dedicated to a single gas purchase contract, without limitation upon the acreage encompassed therein. Further, in Exxon's view, it makes no difference if the producer gathers gas from multiple wells to a central point of delivery, so long as such central delivery point is located *anywhere* within the boundaries of the "the lease," so defined. On the other hand, Exxon contends that gathering *beyond* the boundaries of the lease, *i.e.*, to an off-the-lease delivery point, *does* adds value to the gas, in the sum of $0.01/Mcf, irrespective of the actual distance involved.

Exxon's contention that on-the-lease gathering adds *no* material value to natural gas, whereas off-the-lease gathering does, is quite novel. The relevant RMFP precedents uniformly hold that where the producer transports the gas away from the wellhead, prior to sale, such transportation adds value that must be excluded from the RMFP computation. Exxon I, 88 F.3d at 977; Panhandle, 187 Ct. Cl. at 171-72, 408 F.2d at 716; Shamrock, 35 T.C. at 1030, 1036-37. However, none of the foregoing precedents draw any distinction between the value added by gathering "on the lease" and the value added by gathering "off the lease."

Panhandle clearly demonstrates that such a distinction is without precedent. Therein, as noted above, the taxpayer sold a portion of its gas production from its McPherson No. 1-35 well, located in the Howell Field in Michigan, near the wellhead at a price of $0.325/Mcf. Panhandle, 187 Ct. Cl. at 162; 408 F.2d at 710-711. Given the aforesaid circumstance, the Court of Claims determined that, literally and technically, $0.325/Mcf was a wellhead price for gas produced in the Howell Field. Id. at 171; 408 F.2d at 715-16. However, the taxpayer also sold the remainder of its gas from the McPherson No. 1-35 well, plus all of its gas production from another 13 wells in the Howell Field, at delivery points located some 30 to 40 miles away, pursuant to the same contract and at the same $0.325/Mcf price. Id. at 162; 408 F.2d at 710-711. It was undisputed that the taxpayer's total cost of transporting the gas to the remote delivery points was $0.035/Mcf. Id. at 162; 408 F.2d at 711. Inasmuch as the taxpayer was selling the vast majority of its Howell Field gas at the remote delivery points, the Panhandle court reasoned that the $0.325/Mcf contract price had to be tainted by transportation costs in the sum of $0.035/Mcf and, consequently, could not be truly representative of the market price at the wellhead. Id. at 171-72; 408 F.2d at 716-17. See also Exxon I, 88 F.3d at 974 (summarizing aforesaid circumstances in Panhandle). Therefore, relative to the gas sold at the remote delivery points, the Court of Claims held that "there should be deducted from the 32½¢ per MCF sales price of such gas, the stipulated cost of 3½¢ per MCF to [the taxpayer] of *gathering the gas from its wells and transporting it off the leases* to the [remote] delivery points . . . , resulting in a price of 29¢ per MCF which shall be used with respect to this production," *i.e.*, as the depletable gross income from the property. Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718 (emphasis added).

Significantly, in holding that the $0.035/Mcf cost of transportation had to be deducted from the $0.325/Mcf sale price of the gas, the Panhandle court drew no distinction between transportation "on the lease" and transportation "off the lease." On the contrary, the Court of Claims expressly recognized that the $0.035/Mcf transportation cost deduction included both the taxpayer's cost of "gathering the gas from its wells," *i.e.*, on-the-lease transportation, *and* the cost of "transporting it off the leases to the delivery points," *i.e.*, off-the-lease transportation. Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718. See also id. at

162, 173, 408 F.2d at 711, 717. Thus, Panhandle establishes that Exxon's contention that transportation "on the lease" adds no value to natural gas, whereas transportation "off the lease" does, is without precedent.

Here at bar, of course, and notwithstanding the lack of precedential support for its position, Exxon remains entitled to prove, by a preponderance of the evidence, that any on-the-lease transportation before sale was, in fact, immaterial to the sale price of the gas in the 2,058 transactions in its proposed RMFP sample. Surprisingly, however, at trial, Exxon made no effort to quantify the cost of transportation "on the lease," prior to sale, with respect to the 2,058 transactions in issue. Rather, Exxon relies exclusively upon Mr. Ellis' naked opinion that such on-the-lease transportation "involves cost increments that are so small that they do not even round to a whole cent." Tr. 1222. Mr. Ellis failed to identify and proffer any credible factual basis for his opinion, stating instead that he "would defer to Mr. Platt to give a full explanation of his calculation of [transportation] costs." Id. Yet, Mr. Platt later admitted that, at Exxon's instruction, his transportation cost study addresses only off-the-lease transportation, and totally disregards the distances and costs associated with any on-the-lease transportation.(193) Therefore, the record in fact furnishes no evidentiary support for Mr. Ellis' self-serving opinion that the cost of on-the-lease transportation is immaterial to the sale price of natural gas.

In fact, the record contains creditable evidence, offered by Exxon itself, that discredits Mr. Ellis' view. For example, Mr. Platt himself conceded that the cost of transporting gas is a function of the distance that the gas is transported, without drawing any distinction between on-the-lease transportation and off-the-lease transportation.(194) Moreover, Messrs. Pohler and Buie testified that pipeline companies, for purposes of negotiating gas purchase contracts in 1975, took into account the length and cost of any gathering system that might be required in order to effect delivery of the producer's gas. Specifically, as explained above, a large reserve allows the pipeline company to amortize the cost of a gathering system over more units of purchased gas, thereby lowering the per-unit cost of such gas. See Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 894 (findings to this effect); Panhandle, 187 Ct. Cl. at 218-19 (same). Thus, *before* making the commitment to lay gathering lines to take delivery of the producer's gas at or near the wellheads, pipeline companies frequently demanded assurance that the underlying reserves available for sale would justify the economic investment in such gathering lines.(195) Having noted such contractual arrangements in connection with several of the transactions in controversy, the court found that such arrangements drew *no* distinction whatsoever between on-the-lease gathering and off-the-lease gathering.(196)

The foregoing finding irreversibly undermines Exxon's contention that on-the-lease gathering had no material effect upon the sale price of natural gas in the Texas Gulf Coast/East Texas region in 1975. If Exxon were correct, the court would expect to find that producers and purchasers focused exclusively upon gathering "off the lease," but were totally indifferent about which party had to bear the costs of gathering the gas within the producer's leased acreage. Yet, the court found no instance in which this was so. On the contrary, it is evident that pipeline companies and gas producers routinely took gathering requirements into account in negotiating gas purchase contracts in 1975. Further, due to the costs of gathering, such gas purchase contracts routinely allocated, as between seller and buyer, the obligation to construct the requisite gathering lines or gathering system. On this record, Exxon has failed to establish that pipeline companies and gas producers commonly negotiated such contract provisions solely by reference to off-the-lease gathering, while disregarding any on-the-lease gathering. Consequently, we are constrained to reject, as unproven, Exxon's contention that the costs of transportation "on the lease" had no material effect upon the sale price of natural gas in 1975.

Our conclusion finds further support in certain determinations made by FERC under section 110 of the Natural Gas Policy Act of 1978 (NGPA), Pub. L. No. 95-621, 92 Stat. 3353, 3368 (1978), which authorized FERC to prescribe rules specifying the circumstances under which pipeline companies could pay gathering allowances to gas producers, in addition to the maximum lawful wellhead price. As noted above, FERC issued an interim regulation in 1978 that permitted such allowances to be paid only to the extent the gathering took place "off the lease from which the natural gas was produced." *Natural Gas Policy Act of 1978: Interim Regulations*, 43 Fed. Reg. 56448, 56576 (Dec. 1, 1978), codified at 18 C.F.R. § 271.1105(c)(2) (1979). Thereafter, however, by amendment to its interim regulation in 1980, and promulgation of a final regulation in 1983, FERC eliminated the prohibition on the payment of gathering allowances for on-the-lease gathering. See Order No. 94, *Order Amending Interim Regulations Under the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act*, 45 Fed. Reg. 53099, 53104, 53107-08 (July 25, 1980); *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44497-44498 (Sept. 27, 1983). In so doing, FERC determined that "the 'off lease' criteria was . . . inexact and did not lead to equal treatment between applicants." 45 Fed. Reg. at 53108. Moreover, in the preamble to its final regulation, FERC expressly acknowledged that on-the-lease gathering does, in fact, add value to natural gas, by clarifying that a gathering allowance could be paid even if the gas producer incurred *no* off-the-lease gathering costs. 48 Fed. Reg. at 44498.

Given the aforesaid determinations by FERC -- the federal agency charged by Congress with the duty of regulating sales of natural gas by producers to pipeline companies -- Exxon's contention that on-the-lease gathering adds no value to natural gas, whereas off-the-lease gathering does, is plainly untenable. Particular noteworthy, we think, is FERC's finding that an

on-the-lease/off-the-lease distinction produces inexact results and fails to treat similarly situated gas producers alike. Exxon's on-the-lease criterion exhibits the same flaw, because it absolutely fails to distinguish between two very different situations: (i) a gas producer with a single well, situated on a relatively small lease, connected to a delivery point on that lease by a short gathering line, not exceeding a few hundred feet; and (ii) a gas producer with dozens of wells, situated on multiple leases encompassing many thousands of acres, all of which are connected by an extensive gathering system, involving miles of pipe, to a central delivery point located on any one of the producer's leases. In both scenarios, Exxon's on-the-lease criterion treats the producer's cost of gathering "on the lease" as totally immaterial to the sales price of the gas, irrespective of the actual distances involved.

On Exxon's behalf, Mr. Platt sought to defuse this criticism by opining that extensive, on-the-lease gathering systems were not "common" to the transactions in Mr. Ellis' RMFP study, because one-well and two-well transactions made up over one-half of the 1,809 transactions for which he was able to identify the related well(s). However, inasmuch as the RMFP is a *volume*-weighted average price, the number of transactions involving one or two wells is of relatively little significance. What is important, due to the fact that large-volume transactions exert a greater influence upon the RMFP than small-volume transactions, is the proportionate *volume* of gas associated with the transactions involving one or two wells. Yet, when asked what volume of gas relates to single-well transactions, as a percentage of the total volume represented in the 2,058 transactions in Mr. Ellis' RMFP study, Mr. Platt weakly responded, "I don't know. I haven't computed it."[(197)] Mr. Platt's response, in the court's view, completely negates the probative force of his opinion that extensive on-the-lease gathering systems were not "common" to the transactions in Mr. Ellis' RMFP study. Thus, relative to the transactions in issue, we cannot reasonably infer that on-the-lease gathering from multiple wells, prior to sale, was so uncommon or trivial so as to exercise no material influence upon Mr. Ellis' proposed RMFP computation.

Exxon also argues that when a producer gathers gas from multiple wells to a central delivery point located somewhere on its leased acreage, the producer's intention typically is to centralize its separation and treatment facilities, in order to achieve economies of scale and cost savings, not to add value to the gas by the mere act of transporting it to the central delivery point. In support of this contention, Exxon calls the court's attention to the following opinion testimony given by Mr. Martin on cross-examination:

Q: Is it your understanding that the principal reason producers centralize their separation and treatment facilities is to add value to the gas by virtue of transportation to a central point?

A: No.

Q: No. In fact, isn't it true that the principal reason producers centralize their separation and treatment facility is to realize economies of scale in separation and treating gas?

A: If that occurred, yes.

* * * * *

Q: If what occurred?

A: The centralization of facilities.

Q: The principal reason they do it, though, is to realize economies of scale, is it not?

A: Yes.

Q: It's not to add value by way of transportation?

A: No.

Q: And isn't it further true that in some cases gathering to a central point actually moves the production from a given well away from the purchasing pipeline?

A: Yes.

Tr. 2651-52 (Martin).

For at least two reasons, we think Exxon assigns the foregoing opinion testimony far more significance than it is rightfully due. First, Mr. Martin's testimony cannot be fairly and objectively read, as Exxon urges, as a sweeping admission to the effect that on-the-lease gathering *never* adds material value to natural gas. At most, Mr. Martin did no more than concede that on-the-lease gathering *sometimes* adds no material value to natural gas. Further, even assuming that Mr. Martin's testimony could be read as an unequivocal admission that on-the-lease gathering adds no value to natural gas, the weight of the other probative evidence in the record is, as discussed above, to the contrary. Consequently, even if given the hospitable construction that Exxon advocates, Mr. Martin's opinion testimony would be intrinsically unpersuasive and, thus, not conclusive and binding on the court. Sternberger, 185 Cl. Ct. at 535-36, 401 F.2d at 1016.

Second, the primary focus of the questions posed by counsel for Exxon, and Mr. Martin's responses, *supra*, is the motive behind a typical producer's decision to gather its gas to a central point on its leased acreage. It is essentially undisputed, on this record, that gas producers can achieve economies of scale and cost savings by gathering their gas to centralized compression, dehydration, or processing facilities. Moreover, it is not implausible that the achievement of such economies of scale is typically the "principal reason" (Tr. 2652) that a producer gathers gas to a central point on its leased acreage. However, the question is not whether the gas producer *intends* to add transportation-related value to its gas by gathering it to a central point "on the lease." On the contrary, the question is whether such on-the-lease gathering, *in fact*, adds transportation-related value to the gas.

Common sense instructs that gathering costs incurred by the producer are, more often than not, gathering costs that the purchasing pipeline company is spared. In other words, when the producer has multiple producing wells, if the purchaser can take delivery of the gas at a single, centrally-located point on the producer's leased acreage, the purchaser avoids the cost of constructing an on-the-lease gathering system, i.e., laying a gathering line to each of the producer's wells. As noted above, whether the purchaser incurs or avoids the cost of constructing an on-the-lease gathering system influences the price it will bid for the gas.[(198)] Thus, irrespective of the producer's intentions in gathering its gas to a central delivery point on its leased acreage, the court cannot simply assume, without more, as Exxon would have us do, that such on-the-lease gathering, in every case, has no material effect upon the sale price of the gas.

We turn now to Exxon's final factual contention in support of the validity of its on-the-lease criterion. Specifically, Exxon asserts that the "median lease size" of the transactions in Mr. Ellis' RMFP study that had on-the-lease delivery points (i.e., the transactions given the "Account 800" designation therein) was "a mere 233 acres."[(199)] What this means, according to Mr. Ellis, is that one-half of the on-the-lease transactions he examined involved leased acreage exceeding 233 acres, while the other one-half involved leased acreage of less than 233 acres.[(200)] As to the significance of the foregoing, Exxon argues:

The median lease size for the transactions included in the Ellis study was 233 acres, or approximately 0.36 square miles. Tr. 1211 (Ellis). That translates to a square-shaped lease with sides approximately 0.6 miles long. On such a lease, even indulging Defendant's assumption that the well is located in the exact center of the lease (see June 22, 1998, Oral Arg. Tr. at 29), the well would be no more than 0.3 miles, less than 1600 feet, from the edge of the lease.

Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 6 n.2. In essence, Exxon asks the court to make two findings: (i) that the typical or representative size of the leased acreage associated with the purported on-the-lease transactions in Mr. Ellis' RMFP study is 233 acres; and (ii) that the cost of transporting natural gas away from the wellhead, but within the confines of a 233-acre tract, is so minimal so as to have no material effect upon the sale price of the gas.

However, such findings of fact are impossible to make, on this record, because the court has no way to verify Mr. Ellis' unsubstantiated assertion that the median lease size of the on-the-lease transactions in his RMFP study was, in fact, 233 acres, because Mr. Ellis submitted no workpapers to support his contention. Mr. Ellis' omission is problematic in two respects. First, it underscores Exxon's complete failure to present a systematic, comprehensive study of the costs of on-the-lease transportation, as evidentiary support for its contention that such costs have no material effect upon the sale price of natural gas.(201)

Second, Mr. Ellis admitted that he limited his determination of the median lease size to 300 contract files, representing fewer than 15% of the 2,058 transactions in issue, despite the fact that he had access to hundreds of additional contract files.(202) For this reason, we refuse to view Mr. Ellis' 233-acre estimate of the median lease size as probative evidence that is supportive of Exxon's contention that on-the-lease transportation adds no value to natural gas. The validity of the median lease size as a statistical measure of central tendency, relative to the distribution of lease sizes within Mr. Ellis' 2,058-transaction RMFP sample, is dependent upon the number of transactions on which it is based. This is, of course, the very same statistical principle that underlies "the goal of maximizing the number of transactions included" in the RMFP sample. Exxon I, 88 F.3d at 977-78. Stated differently, as the proportion of the 2,058 transactions in Mr. Ellis' RMFP study that are included in the median lease size determination increases, the median lease size should tend to more closely approximate the typical or representative size of the leased acreage associated with the 2,058 transactions in Mr. Ellis' RMFP study. Here at bar, however, Mr. Ellis not only failed to utilize every available contract, but also failed to offer any justification for his failure to do so. In addition, Mr. Ellis neglected to identify which 300 contracts he used to estimate the median lease size. Thus, on this record, the court is utterly unable to ascertain whether Mr. Ellis' 233-acre estimate of the median lease size is reasonably representative of the size of the leased acreage associated with the transactions in his RMFP study.

Moreover, we think Mr. Ellis' 233-acre estimate of the median lease size is conspicuously flawed and speculative insofar as it relates to transactions involving multiple wells. From the standpoint of making reasonably certain that the RMFP computation is untainted by any material value attributable to on-the-lease transportation of the gas, multiple-well transactions are of particular concern, because the court must be mindful of the probability that the producer had an on-the-lease gathering system in place, connecting its multiple wells to a central delivery point. This is no illusory issue. On the contrary, in terms of the volume sold (Mcf), a substantial majority of the gas associated with the 649 purported on-the-lease transactions in Mr. Ellis' RMFP study (*i.e.*, the transactions given the "Account 800" designation therein), relates to transactions that involved multiple wells.(203)

Applied to multiple-well transactions, Mr. Ellis' estimate of the median lease size would, if accepted as valid, imply that producers typically drill gas wells in accordance with a physical spacing of 233 acres per well. However, the weight of the evidence convinces us that 233 acres per well is an unrealistically low estimate of typical gas well spacing in the Texas Gulf Coast/East Texas region. In particular, we note the conflict between Mr. Ellis' 233-acre estimate and Mr. Buie's testimony, also given on Exxon's behalf, that the Texas Railroad Commission typically set a producer's minimum gas well spacing at "360 acres or maybe 640 acres" per well in 1975. Tr. 584.(204) Moreover, the contract files in PX 14a and PX 14b disclose that gas producers often leased acreage exceeding that required to satisfy the minimum well spacing requirements set by the Railroad Commission -- in some cases, over 1,000 acres per well.(205)

Given the foregoing, we are constrained to hold that Mr. Ellis' estimate of the median lease size, at 233 acres per well, significantly understates the size of the actual leased acreage typically associated with the multiple-well transactions in issue and, in turn, the cost of gathering gas from multiple wells to an on-the-lease central delivery point. Due to the fact that the volume of gas represented in Mr. Ellis' RMFP study relates predominantly to multiple-well transactions, the costs of such on-the-lease gathering, if left unaccounted for, could materially distort the RMFP computation.[(206)] Therefore, the court refuses to accept, on the basis of Mr. Ellis' unfounded assertion that the median lease size is 233 acres, Exxon's contention that on-the-lease transportation typically covers such short distances as to be totally valueless.

In short, Exxon has failed to present any credible, probative evidence in support of its contention that on-the-lease transportation adds no material value to natural gas. Given such, Exxon cannot cure its failure of proof by overlaying a self-serving statistical "gloss" on its argument, in the form of Mr. Ellis' bland, unsubstantiated assertion regarding the median lease size of the on-the-lease transactions in his study. As a matter of law, if the court is to accord any probative weight to Mr. Ellis' invocation of a statistical measure, *i.e.*, the putative median lease size, in support of his opinion that on-the-lease transportation is valueless, then we must hold Mr. Ellis to the same standards of expertise that govern the work of reputable statisticians generally. In short, our objective, in applying this requirement, is to ensure that Mr. Ellis' statistical determinations meet the standard of evidentiary reliability enunciated in Daubert v. Merrell Dow Pharmaceuticals, Inc., 509 U.S. 579, 589-92 (1993), and Kumho Tire Co., Ltd. v. Carmichael, 119 S. Ct. 1167, 1175-76 (1999).[(207)] Under that standard, we are obliged to "make certain that an expert, whether basing testimony upon professional studies or personal experience, employs in the courtroom the same level of intellectual rigor that characterizes the practice of an expert in the relevant field." Kumho Tire, 119 S. Ct. at 1176.

Here at bar, in stark contradiction to the aforesaid principle, Mr. Ellis sought to avoid, not to adhere to, the standards that normally govern the work of competent statisticians. Notwithstanding his determination of the putative median lease size, Mr. Ellis failed to supplement his analysis with an estimate of the mean, or average, lease size, for the purpose of comparing those two measures of central tendency, or with any statistical measure of the dispersion, or variability, of lease size, such as the standard deviation.[(208)] Further, when asked whether he had any recollection as to what the mean lease size was, Mr. Ellis declined to give a direct response, stating instead: "Given the nature of acreage, I wouldn't consider the mean to be a relevant measure of distribution because it could be so greatly skewed by a single large lease. . . . I do not believe that a mean or average, in describing acreage, is a meaningful measure of the central distribution or tendency." Tr. 1213. We find such subjective response to be utterly unconvincing and nonprobative. While it is true that the mean lease size could be distorted by one or more outliers, *i.e.*, exceptionally large leases, as Mr. Ellis maintained, that does not necessarily suggest that the court would be so easily misled. Indeed, by the simple expedient of presenting a tabulation of the lease sizes that he used in determining the alleged median lease size, Mr. Ellis could have readily brought the existence of any such outliers to the court's attention.[(209)] Under the standard of evidentiary reliability laid down in Daubert and Kumho Tire, Mr. Ellis' unexplained failure to apply recognized methods of statistical analysis, other than his unsubstantiated estimate of the median lease size, in connection with the size of the leases represented in his RMFP study, or even to make his leased acreage data available for the court's inspection, casts incurable doubt upon the veracity of his opinion that on-the-lease transportation is without value.

G. *Summary -- Validity Of Exxon's On-The-Lease Criterion*

To summarize all of the foregoing, Exxon's contention is that *every* sale of raw gas at a delivery point located *anywhere* on the producer's "lease," expansively defined by Exxon to include an aggregation of multiple common-law oil and gas leases, with no discernible limitation upon the size of the acreage encompassed therein, is a transaction in which the sale price of the gas was untainted by transportation before sale. Against this background, we hold that Exxon has failed to demonstrate that the validity of its on-the-lease criterion is supported by either legal authority or the evidence in the record. First, as a matter of law, we hold that the doctrine of collateral estoppel, on this record, does not prevent the Government from litigating the validity of Exxon's on-the-lease criterion, here at bar, because Exxon has not shown that such issue was actually litigated, decided, and essential to the judgment in Exxon I, 88 F.3d 968, 33 Fed. Cl. 250. Second, we reject, as legally untenable, Exxon's argument that authority for its on-the-lease criterion may be found in Treas. Reg. § 1.613-3(a), and Panhandle, 187 Ct. Cl. 129, 408 F.2d 690. In fact, as explained above, Exxon's on-the-lease criterion represents a significant and unjustified *expansion* of Panhandle's definition of a qualifying wellhead sale, *i.e*., a sale of raw gas "on the lease" *and* "near the wellhead." Panhandle, 187 Ct. Cl. at 137, 162, 163, 172, 175, 408 F.2d at 696, 710, 711, 716, 717, 718. Third, turning to the factual merits of Exxon's position, we also hold that the record fails to support Exxon's assertion that, as of 1975, the natural gas industry and the Federal Power Commission routinely utilized an on-the-lease/off-the-lease distinction to differentiate between wellhead sales and non-wellhead sales. Fourth, we hold that Exxon's contention that on-the-lease transportation *never* adds material value to natural gas is unsupported by credible, probative evidence in the record. Accordingly, and in summary, we are constrained to hold that Exxon's on-the-lease criterion is not a valid standard by which the court can identify transactions in which the producer added no material value to the gas, prior to sale, by transporting it away from the wellhead.

Moreover, on this record, it is not feasible to cure any tainted transactions, as Exxon urges, merely by subtracting the cost of transportation from the sale price of the gas, in accordance with the "preferable" method explicated in Exxon I, 88 F.3d at 977-78. We find Mr. Platt's transportation cost study useless, in this respect, inasmuch as it totally disregards the cost of on-the-lease transportation. In addition, Mr. Platt's flat $0.01/Mcf deduction for off-the-lease transportation rests upon his overbroad, speculative assumption that such transportation typically covered no more than one mile in the Texas Gulf Coast/East Texas region in 1975.[(210)]

Correctly anticipating that the court would find Mr. Platt's transportation cost study deficient and unacceptable, Exxon argues alternatively that the court should apply a flat $0.05/Mcf transportation cost deduction to the sale price of the gas in each of the 2,058 transactions in Mr. Ellis' RMFP study. As support for its position, Exxon cites certain determinations that FERC made in the early 1980s, relating to the delivery, *i.e*., gathering, allowances that gas producers were permitted to charge, in addition to the maximum lawful wellhead prices established by FERC, under section 110 of the Natural Gas Policy Act (NGPA) of 1978, *supra*. See *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44507-08 (Sep. 27, 1983), codified at 18 C.F.R. § 271.1104(d)(1) (1984). With respect to "old," pre-NGPA gathering systems, the construction of which commenced before November 9, 1978 (the effective date of the NGPA), FERC allowed gas producers to recover gathering costs not exceeding the sum of $0.05/MMBtu, regardless of the length of the producer's gathering system. 18 C.F.R. § 271.1104(d)(1)(i) (1984). According to Exxon, the foregoing demonstrates that $0.05/Mcf is a reasonable maximum transportation cost deduction for the 2,058 transactions in Mr. Ellis' RMFP study.

We disagree. Exxon fails to give due consideration to the fact that FERC authorized much larger gathering allowances for "recent," post-NGPA gathering systems, the construction of which commenced on or after November 9, 1978. 18 C.F.R. § 271.1104(d)(1)(ii) (1984). Specifically, with respect to such post-NGPA gathering systems, gas producers were permitted to recover gathering costs in the sum of $0.07/MMBtu for the first mile, or fraction thereof, that the gas was transported away from the wellhead or field separator, plus $0.02/MMBtu for each additional mile, or fraction thereof, up to a maximum distance of 20 miles (*i.e*., a maximum gathering allowance of $0.45/MMBtu). Id. FERC adopted the foregoing rule after making an exhaustive study of gathering costs, including the solicitation and receipt of numerous comments from the natural gas industry and the general public, with the objective of establishing a representative mileage-based gathering allowance that would generally permit the full recovery of gathering costs. See 48 Fed. Reg. at 44496 (summarizing background of FERC proceedings).

Conversely, in establishing a flat $0.05/MMBtu maximum gathering allowance for pre-NGPA gathering systems, FERC sought to balance the need to allow producers "adequate cost recovery for representative old delivery systems," *i.e*., pre-NGPA gathering systems, against "the risk of overcompensation." 48 Fed. Reg. at 44498. In so doing, FERC expressly noted that the regulatory policies set by its pre-NGPA predecessor agency, the FPC, and the terms of pre-NGPA gas sale contracts, generally "did not afford total recovery of the [producer's] costs of providing delivery services," *i.e*., gathering. 48 Fed. Reg. at 44497. FERC observed, further, that by collecting a gathering allowance of $0.05/MMBtu, gas producers in the Texas Gulf Coast area would become entitled to "several times the amount they were previously permitted" under pre-NGPA law. 48 Fed. Reg. at 44497.(211) In short, FERC sought to avoid conferring a perceived economic windfall upon producers who had entered into pre-NGPA gas sale contracts without any reasonable expectation of being able to charge a substantial gathering allowance.(212) Thus, whereas the FERC gathering allowance for post-NGPA gathering systems was intended to permit gas producers to fully recover the representative costs of installing and operating a gathering system, the less generous gathering allowance for pre-NGPA gathering systems permitted only a *partial* recovery of such costs. Consequently, we reject Exxon's contention that the FERC pre-NGPA gathering allowance of $0.05/MMBtu (restated by Exxon as $0.05/Mcf) is a reasonable maximum transportation cost deduction for the 2,058 transactions in Mr. Ellis' RMFP study.

Moreover, lacking an adequately developed record concerning the actual distances between wellheads and delivery points, relative to the 2,058 transactions in Mr. Ellis' RMFP study, the court is unable to determine a reasonable transportation cost deduction by applying the FERC mileage-based allowance for *post*-NGPA gathering systems, *supra*. Because the FERC post-NGPA methodology takes account of the actual distance the gas is transported before sale, it would likely produce a more reasonable estimate of gathering costs than Mr. Platt's approach.(213) However, as explained herein, *supra*, Exxon has failed to prepare and submit a reasonably thorough, systematic study of the actual distances between wellheads and delivery points, with respect to each of the 2,058 transactions in Mr. Ellis' RMFP study. Without such a study, it would be pure conjecture for this court to attempt to determine transportation cost deductions for the 2,058 Ellis transactions, under the mileage-based FERC methodology for post-NGPA gathering systems. Thus, on this record, we reject Exxon's invitation to apply the so-called "preferable" method explicated in Exxon I, 88 F.3d at 977-78, for the purpose of cleansing the 2,058 Ellis transactions of any value added by the producer's transportation of the gas away from the wellhead, prior to sale.

Given the foregoing, we hold that all of the 1,409 purported off-the-lease transactions in Mr. Ellis' RMFP study (*i.e*., the transactions given the "Account 801" designation therein) are ineligible for inclusion in Exxon's 1975 RMFP computation. We reach this conclusion on the grounds that (i) the sale prices in the 1,409 off-the-lease transactions include value added by transportation; and (ii) Exxon has failed to prove the amount of such added value with reasonable certainty, so as to permit an appropriate deduction to be made from the sale price of the gas in each such transaction. Exxon I, 88 F.3d at 977.

On like grounds, we hold that the 46 *de jure* Account 801 transactions redesignated by Mr. Ellis as *de facto* Account 800 transactions, *supra*, are also ineligible for inclusion in the RMFP computation.(214) A *de jure* Account 801 transaction, as explicated above, is a gas purchase that an interstate pipeline company classified under NARUC Account 801 in a 1975 annual report (Form 2) filed with the FPC. Under the Panhandle presumption, *de jure* Account 801 transactions are rebuttably presumed *not* to qualify for inclusion in the RMFP computation. Exxon I, 88 F.3d at 977; Panhandle, 187 Ct. Cl. at 151-

52, 408 F.2d at 704-05. This is so because, in an Account 801 transaction, "the *producer* transports the gas away from the wellhead," prior to sale. Exxon I, 88 F.3d at 977 (emphasis in original). As noted above, Mr. Ellis redesignated the aforesaid 46 *de jure* Account 801 transactions as *de facto* Account 800 transactions solely on the basis of his subjective judgment that such transactions met Exxon's on-the-lease criterion, a standard that we have held to be legally and factually untenable. Thus, Exxon has failed to rebut the Panhandle presumption, relative to the 46 *de jure* Account 801 transactions in question, and those 46 transactions must be excluded from the RMFP computation.

At this juncture, 603 transactions remain under consideration for inclusion in Exxon's 1975 RMFP computation, consisting of: (i) 158 *de jure* (interstate) Account 800 transactions; and (ii) 445 *de facto* (intrastate) Account 800 transactions, *i.e.*, on-the-lease transactions given the "Account 800" designation in Mr. Ellis' RMFP study. As discussed above, 170 of those transactions are undisputed wellhead sales, those being the 158 *de jure* Account 800 transactions and 12 *de facto* Account 800 transactions conceded by the Government to qualify as wellhead sales. The qualification of the remaining 433 *de facto* Account 800 transactions is unagreed.

In determining whether any of the 433 transactions in dispute qualify for inclusion in the RMFP computation, the court must consider whether the record at bar establishes, on grounds other than Exxon's discredited on-the-lease criterion, that no material value was added to the gas, prior to sale, by transportation. Exxon I, 88 F.3d at 977. Additionally, in evaluating the qualification of said transactions, we must consider whether the gas was either compressed or dehydrated before sale. Id. at 978-79, 33 Fed. Cl. at 275-77. If a transaction involved the sale of gas that was either compressed or dehydrated, the court must then decide whether to exclude the transaction, or to deduct the applicable costs of compression and dehydration, if supported by the record, from the sale price under the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78. First, however, we shall consider whether Exxon has met its burden of showing that the gas at issue was not processed, prior to sale, for the extraction of liquefiable hydrocarbons. Id. at 976; Hugoton II, 172 Ct. Cl. at 455-56, 349 F.2d at 425.

H. *Transactions Involving Reservations Of Gas Processing Rights To The Seller*

1. *Background*

Unlike the controversy over transportation of the gas away from the wellhead, *supra*, the legal and factual issues pertinent to gas processing are relatively simple. As a matter of law, sales of processed gas are unconditionally disqualified from inclusion in the RMFP computation, which must reflect the "price of the . . . gas *before* [its] conversion" into a refined product. Treas. Reg. § 1.613-3(a) (emphasis added). See Cannelton, 364 U.S. at 86; Exxon I, 88 F.3d at 976; Hugoton II, 172 Ct. Cl. at 455-56, 349 F.2d at 425. From a factual standpoint, therefore, the only question for decision is whether Exxon has proven that the gas was, in fact, sold in raw, unprocessed form in each of the 2,058 transactions in Mr. Ellis' RMFP study.

Regarding the transactions at issue here, *i.e.*, sales of gas by producers to pipeline companies, it is undisputed that the producer's right to process its gas, prior to sale and delivery to the purchaser, hinged upon whether the gas purchase contract expressly reserved such processing rights to the producer. Although the operative language differs slightly from contract to contract, depending upon the identity of the pipeline company in question, such reservations of processing rights are essentially standardized. For example, with respect to transaction L0336, in which Expando Production Co. was the producer and seller of the gas, and Lo-Vaca Gathering Co. was the buyer, the contract, dated February 22, 1974, provides in pertinent part, as follows:

RESERVATIONS OF SELLER

Seller hereby expressly reserves the following rights with respect to Seller's Gas Reserves and the leases subject to this Contract:

* * * * *

3. The right to process the gas prior to delivery for the recovery of liquefiable hydrocarbons . . . .

PX 14a, L0027024-25. With respect to the 2,058 transactions in Mr. Ellis' RMFP study, the parties have stipulated that processing rights were contractually reserved to the producer in 500 such transactions.(215) In addition, upon examining the contract files relating to transactions G0806, G0922, L0017, L0170, and L0498, the court determined that those five transactions also involved a reservation of processing rights to the producer.(216) Thus, in 505 of the transactions in issue, the producer had the contractual right to process its gas.

The factual issue the court must now resolve, relative to the qualification of the foregoing 505 transactions for inclusion in the RMFP computation, is whether the producers in question, in fact, exercised their reserved processing rights in 1975 and, consequently, sold processed gas. For clarity of presentation, we categorize these 505 transactions as follows:

Interstate transactions:

De jure Account 800 transactions 58

De jure Account 801 transactions 128

___

Subtotal -- interstate transactions 186

Intrastate transactions:

De facto Account 800 transactions 130

De facto Account 801 transactions 189

___

Subtotal -- intrastate transactions 319

___

Total -- transactions with reserved processing rights 505.

Under the Panhandle presumption, *supra*, the 186 interstate transactions involving a reservation of processing rights to the producer are presumed to be sales of raw gas, subject to rebuttal by contrary evidence from the underlying contract files. See Exxon I, 88 F.3d at 977; Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05. This is so because the interstate pipeline companies in question reported those 186 transactions under Account 800 (wellhead purchases) or Account 801 (field line purchases) in their 1975 Forms 2, filed with the FPC, rather than under Account 802 (natural gas gasoline plant outlet purchases), as would be the case if the producer sold processed gas. Inasmuch as neither party has rebutted the Panhandle presumption with respect to the aforesaid 186 transactions, the court finds that those 186 transactions were sales of raw, unprocessed gas.(217) Accordingly, the following discussion addresses only the 319 *intra*state transactions involving reserved processing rights.

2. *Contentions Of The Parties*

Exxon contends that in the course of preparing his RMFP study, Mr. Ellis properly excluded any and all intrastate transactions in which the producer was, in fact, selling processed gas in 1975. In making such determinations, Mr. Ellis consulted GUD annual reports filed by intrastate pipeline companies for the year 1975, and the underlying pipeline company gas purchase contract files (PX 14a and PX 14b). Where such documents affirmatively indicated that the producer had exercised its reserved processing right and was selling processed gas in 1975, Mr. Ellis excluded the transaction from his RMFP study. Conversely, from the *absence* of any affirmative indication in such documents that the producer's reserved processing right had, in fact, been exercised (where such a right existed), as of 1975, Mr. Ellis hospitably drew the *negative* inference that the producer was selling raw gas.

Messrs. Buie and Eakin assisted Mr. Ellis' determinations by reviewing the intrastate gas purchases made in 1975 by their respective former employers, Houston Pipe Line Company (HPL) and Lo-Vaca Gathering Company. Mr. Buie reviewed the tabulation of gas purchases in HPL's 1975 GUD annual report, and the underlying HPL contract files, in order to differentiate purchases of raw gas from purchases of processed gas. According to Mr. Buie, HPL's contract files would ordinarily contain evidence of a gas producer's election to exercise its reserved processing right, including: (i) the producer's written notice to HPL; (ii) correspondence relating to the change in delivery point, *i.e*., from a point on the producer's leased acreage, or in the field, to the outlet of the gas processing plant; and (iii) plant settlement statements, *i.e*., statements detailing the quantity of liquefiable hydrocarbons extracted for the producer's account and the quantity of residue gas delivered to HPL at the plant outlet. Exxon argues, further, that Mr. Buie relied upon his personal recollection as to whether HPL's 1975 gas purchases were of raw gas or processed gas.

Mr. Eakin took a somewhat different approach in reviewing Lo-Vaca's 1975 gas purchases, due to the fact that Lo-Vaca failed to individually itemize its gas purchases in its 1975 GUD annual report. Specifically, in addition to reviewing Lo-Vaca's gas purchase contract files, Mr. Eakin had to rely upon Lo-Vaca's internal accounting records in order to distinguish raw gas purchases from purchases of processed gas. As explained above, Lo-Vaca's internal account codes, by which it classified its gas purchases, were modeled upon the NARUC Uniform System of Accounts. Thus, Mr. Eakin treated gas purchases recorded under Lo-Vaca Accounts 41 and 42, corresponding to NARUC Accounts 800 (well head purchases) and 801 (field line purchases), as raw gas purchases. Conversely, Mr. Eakin concluded that gas purchases recorded under Lo-Vaca Account 43, which corresponded to NARUC Account 802 (natural gas gasoline plant outlet purchases), were purchases of processed gas.

In response to the foregoing, with respect to each of the 319 *intra*state transactions in which the contract reserved processing rights to the producer, the Government contends that Exxon has failed to carry its burden of proving that each such producer did *not* exercise its reserved processing rights during the year 1975. The incurable flaw in Exxon's case, in the Government's view, is Exxon's failure to prove that the pipeline company gas purchase contract files, received in evidence as PX 14a and PX 14b, are the *complete* contract files relating to the 1975 gas purchases in issue. Without that indispensable evidentiary foundation, the Government argues, the *absence* of any document indicating that the producer exercised its reserved processing rights, from the pertinent contract file in PX 14a or PX 14b, cannot logically support the negative inference that the producer was, in fact, selling raw gas in 1975.(218) For the reasons set forth below, the court agrees with the Government's argument.

3. *Discussion*

At trial, as further discussed below, Exxon did not lay the usual evidentiary foundation for the admission of the pipeline company contract files (PX 14a and PX 14b) into evidence. Ordinarily, for such business records to be admissible, the proponent of such records must satisfy the requirements of Federal Rule of Evidence 803(6), which provides, in pertinent part:

The following are not excluded by the hearsay rule, even though the declarant is available as a witness.

* * * * *

(6) Records of regularly conducted activity. A memorandum, report, record, or data compilation, in any form, of acts, events, conditions, or diagnoses, made at or near the time by, or from information transmitted by, a person with knowledge, if kept in the course of a regularly conducted business activity, and if it was the regular practice of that business activity to make the memorandum, report, record, or data compilation, *all as shown by the testimony of the custodian or other qualified witness*, unless the source of information or the method or circumstances of preparation indicate lack of trustworthiness.

Fed. R. Evid. 803(6) (emphasis added). Authenticated records kept in the course of a regularly conducted business activity are considered admissible hearsay, because such records are deemed sufficiently trustworthy to serve as affirmative proof of the matters asserted therein, as follows:

The element of unusual reliability of business records is said variously to be supplied by systematic checking, by regularity and continuity which produce habits of precision, by actual experience of business in relying upon them, or by a duty to make an accurate record as part of a continuing job or occupation.

Advisory Committee Note to Rule 803(6). Conversely, business records are inadmissible if "the source of information or the method or circumstances of preparation indicate *lack of trustworthiness*." Fed. R. Evid. 803(6) (emphasis added). Therefore, in the usual case, a litigant offering purported business records into evidence must present eyewitness testimony from the custodian of such records, or another properly qualified witness, regarding the manner in which the business organization in question compiled and maintained such records. See Jack B. Weinstein & Margaret A. Berger, *Weinstein's Federal Evidence* § 803.11, at 803-55 to 803-56 (Joseph M. McLaughlin ed., 2d ed. 1998) ("The testimony of the custodian or another qualified witness who can explain the record-keeping of the organization is ordinarily essential.").

As an alternative to establishing the trustworthiness of putative business records with testimony from their custodian, a foundation for admissibility under Rule 803(6) may, of course, be supplied by the stipulation of the parties. Weinstein & Berger, *supra*, § 803.11, at 803-60. Thus, here at bar, the parties jointly stipulated that the pipeline company contract files (PX 14a and PX 14b) "are true copies of documents kept by the indicated business enterprises in the ordinary course of business" (PX 19 at 1-2) and, further, that such contract files "may be admitted into evidence without objection by either party." PX 22 at 17. Pursuant to the aforesaid stipulations, PX 14a and PX 14b were received in evidence without objection on the first day of trial. Consequently, Exxon apparently saw no need to, and in fact did not, present any foundational testimony from the custodians of the pipeline company contract files in PX 14a and PX 14b. That circumstance gives rise to Exxon's present dilemma.

With respect to each of the 505 transactions in issue, involving a reservation of processing rights to the producer, Exxon asks the court to draw a negative inference -- that the gas producer did *not* exercise its reserved processing rights and process its gas in 1975 -- from the *absence* of any document in the related pipeline company gas purchase contract file, *i.e.*, PX 14a or PX 14b, that affirmatively indicates that the producer processed its gas in 1975. In evaluating the propriety of Exxon's proposed negative inference, the court finds instructive the requirements of Federal Rule of Evidence 803(7), which provides as follows:

(7) Absence of entry in records kept in accordance with the provisions of paragraph (6). Evidence that a matter is *not* included in the memoranda, reports, records, or data compilations in any form, kept in accordance with the provisions of paragraph (6) [*i.e.*, Rule 803(6), relating to the admissibility of business records as affirmative proof of a matter], *to prove the nonoccurrence or nonexistence of the matter*, if the matter was of a kind of which a memorandum, report, record, or data compilation was regularly made and preserved, *unless the sources of information or other circumstances indicate lack of trustworthiness*.

Fed. R. Evid. 803(7) (emphasis added).

Rule 803(7), like its counterpart, Rule 803(6), primarily focuses upon the trustworthiness of the business records in question. However, when a litigant offers the *absence* of a business record as proof that an event did *not* take place, under Rule 803(7), the trustworthiness requirement assumes heightened importance, as a leading evidence treatise explains:

Litigants sometimes seek to prove that an event did not occur by showing the absence of a record that it took place. Demonstrating that the records were kept in such a way that the matter would have been recorded had it occurred is crucial to any such showing. Although the testimony of the custodian of the records or other qualified witness is not explicitly required [by Rule 803(7)], testimony by such a person will usually be necessary to overcome a charge of untrustworthiness.

Weinstein & Berger, *supra*, § 803.12, at 803-84 (citing cases). See also Wright & Graham, *Federal Practice and Procedure* § 6758, at 393 (1998) ("The testimony of the custodian of the record or other qualified person is necessary in order to lay the proper foundation [under Rule 803(7)]."). Yet another evidence treatise notes:

If records are routinely kept (or entries are routinely made), they are likely to be *complete and comprehensive*, so nonmention (or nonexistence of a record or entry) is a good indication that act, event, or condition did not occur or exist. The foundation requirements for showing there is no record or entry are similar to those for business records themselves, with some adjustments. In lieu of showing that records were routinely kept by a regular business, the party proving nonmention should show such a business routinely kept records of matters like the one not mentioned; in lieu of showing the matter was recorded contemporaneously by a person with firsthand knowledge, the proponent should show the matter not mentioned would have come to the attention of regular recordkeepers and would have been noticed.

Christopher B. Mueller & Laird C. Kirkpatrick, *Evidence* § 8.51, at 995 (1995) (emphasis added).

At trial, Exxon laid no evidentiary foundation of the sort described above, relative to the contract files in PX 14a and PX 14b. As the Government correctly observes, the parties have not stipulated as to the manner of origin, purpose, or completeness of the contract files in PX 14a and PX 14b. Rather, the parties merely stipulated that PX 14a and PX 14b "are true copies of documents kept by the indicated businesses in the ordinary course of business." PX 19 at 1-2. The only evidence in the record that even remotely resembles the foundation required under Rule 803(7) is Mr. Buie's testimony that HPL's contract files would ordinarily contain evidence of a gas producer's election to exercise its reserved processing right. However, the record at bar fails to show that Mr. Buie had any custodial responsibility for HPL's gas purchase contract files, or that he otherwise had any probative personal knowledge of how HPL assembled and maintained those records. Nor did Mr. Buie's testimony address, in any respect, the *completeness* of the HPL contract files in PX 14a and PX 14b. Moreover, inasmuch as Mr. Buie's testimony related solely to HPL, his former employer, it tells the court nothing about the pedigree and completeness of the many contract files in PX 14a and PX 14b that relate to the numerous other pipeline companies doing business in the Texas Gulf Coast/East Texas region in 1975.

Our own examination of the contract files in PX 14a and PX 14b gives no assurance whatever that such contract files are *complete*. On the contrary, the court frequently found chronological gaps in those files and other indicia of incompleteness. This should come as no surprise, inasmuch as this litigation concerns the year 1975 and, as the Government points out, it is a matter of common experience that business enterprises typically cull, misplace, or fail to properly maintain old files and records that are no longer needed for current business operations.[(219)] Thus, it cannot be said that the contract files in PX 14a and PX 14b are sufficiently trustworthy, under Rule 803(7), to merit the negative inference that Exxon seeks to claim. Given that the completeness of the contract files in PX 14a and PX 14b is unproven, the court cannot logically draw any particular inference from the absence, in any such contract file, of a document indicating that the producer had exercised its reserved processing rights in 1975. The absence of such a document could mean, as Exxon urges, that the producer declined to exercise its reserved processing rights. On the other hand, it could mean that said document existed at one time, but was subsequently lost, destroyed, misfiled, or otherwise excluded from the contract file, or portion thereof, that is in the record at bar, *i.e.*, PX 14a or PX 14b. We are in no position to say which is the case, on this record, and we refuse to simply speculate about the matter. Therefore, we are constrained to hold that Exxon is not entitled to the negative inference that it claims.

Exxon concedes that the completeness of the pipeline company contract files in PX 14a and PX 14b is unproven,[(220)] but nonetheless asserts that its proposed negative inference is justified on other grounds. Specifically, Exxon contends that before trial, the Government knew of and directly participated in the process by which Exxon obtained the contract files in PX 14a and PX 14b, by subpoena, from the pipeline companies in question. Further, Exxon argues, the Government received complete copies of all the documents that each pipeline company produced in response to Exxon's subpoenas. Notwithstanding the foregoing, the Government raised no objection to the completeness of the contract files in PX 14a and PX 14b until almost nine months after trial. In essence, Exxon implies that the Government is somehow estopped from contesting the completeness of the contract files in PX 14a and PX 14b, due to its participation in the process of obtaining those files, or that the Government's objection to the incompleteness of the contract files in PX 14a and PX 14b was untimely and, therefore, waived.

However, even assuming, *arguendo*, that the Government waived, or is estopped from raising, any objection to the incompleteness of the contract files in PX 14a and PX 14b, that would not compel the court, sitting as the trier of fact, to make a finding that such contract files are complete. A litigant's failure to raise an evidentiary objection cannot, *ipso facto*, enhance the probative weight of evidence that is otherwise incompetent as proof of a particular fact in controversy.[(221)] As explained above, no contract file in PX 14a and PX 14b can logically support a negative inference that the producer's reserved processing rights went unexercised in 1975, because the completeness of such contract files is unproven. Contrary to Exxon's assertion, the Government's failure to raise an incompleteness objection at trial cannot transform those contract files and make them whole. Moreover, by stipulating that PX 14a and PX 14b were admissible without objection, the parties did not, as a consequence, render those contract files complete, when in literal fact there is no evidence that such files are complete. In short, it is axiomatic that the litigants cannot stipulate the court into error. Dillon, Read & Co., Inc. v. United States, 875 F.2d 293, 300 (Fed. Cir. 1989); Kaminer Constr. Corp. v. United States, 203 Ct. Cl. 182, 197, 488 F.2d 980, 988 (1973). Thus, whereas the parties' stipulation of admissibility made PX 14a and PX 14b admissible as business records under Rule 803(6), that did not automatically make PX 14a and PX 14b also admissible under Rule 803(7), as evidence of the nonoccurrence of exercises of reserved processing rights. Consequently, in evaluating the probative weight of the contract files in PX 14a and PX 14b, the court is entitled to consider "circumstances [that] indicate lack of trustworthiness," Fed. R. Evid. 803(7), including the evident incompleteness of those contract files. Having done so, we hold that Exxon's proposed negative inference is fundamentally untenable.

Exxon's efforts to affirmatively prove that no reserved processing rights were exercised in 1975, with respect to the 319 intrastate transactions involving such rights, fare no better than Exxon's proposed negative inference. Mr. Eakin's attempt to utilize the internal accounting records of Lo-Vaca Gathering Company, his former employer, in order to distinguish Lo-Vaca's 1975 raw gas purchases from its purchases of processed gas, is gravely flawed. It is true that Lo-Vaca Accounts 41 ("Purchase from Wellhead") and 42 ("Purchase from Field Lines") purport to signify raw gas purchases, whereas Lo-Vaca Account 43 ("Purchase from Gasoline Plant Outlet") purports to signify purchases of processed gas. However, Mr. Eakin admitted that he was unable to obtain any Lo-Vaca accounting records that categorize Lo-Vaca's 1975 gas purchases in the foregoing manner and, therefore, had to rely upon Lo-Vaca's accounting records for the year 1974.[(222)] Plainly, the character of Lo-Vaca's gas purchases in *1975* cannot be reliably determined by sole reference to Lo-Vaca's *1974* accounting records, because such records fail to address any post-1974 events -- including, specifically, a gas producer's decision to exercise its reserved processing rights and sell processed gas to Lo-Vaca.[(223)] Accordingly, from the standpoint of ascertaining whether Lo-Vaca's 1975 gas purchases involved raw gas or processed gas, the court finds that Mr. Eakin's determinations, based upon Lo-Vaca's 1974 internal accounting records, are without basis in fact and entitled to no probative weight.

We also reject, as unsubstantiated by the record, Exxon's assertion that Mr. Buie relied upon his personal recollection of Houston Pipe Line Company's 1975 gas purchases, for purposes of differentiating HPL's raw gas purchases from its purchases of processed gas. In support of this contention, Exxon cites certain vague, generalized statements in Mr. Buie's report, to the effect that he had personal knowledge of "some," but not all, of the delivery points at which HPL bought gas in 1975. PX 2 at 23. However, at trial, Exxon failed to elicit any pointed testimony from Mr. Buie regarding the exercise, or non-exercise, of reserved processing rights by a producer, with respect to any specific 1975 HPL gas purchase included in Mr. Ellis' RMFP study, so that the court could gauge the quality and accuracy of Mr. Buie's purported recollections of whether HPL had bought raw gas or processed gas in such transactions.

Moreover, it is evident that Mr. Buie's putative "recollection" of HPL's 1975 gas purchases rests largely upon subjective judgments that he formed upon examining HPL's 1975 GUD annual report and the HPL contract files in PX 14a and PX 14b. Although HPL's 1975 GUD annual report purports to designate gas purchases made at gas processing plants, rather than on the producer's lease or at a common delivery point in a producing field, nothing in the record gives any assurance that such designations accurately and consistently reflect the character of the underlying transactions.[(224)] Nor does the record show that Mr. Buie, during his employment with HPL, had any responsibility for, or personal knowledge of, the manner in which HPL prepared its GUD annual reports.

Further, in his report, Mr. Buie admits that his reliance upon the HPL contract files in PX 14a and PX 14b was a necessary consequence of his imperfect recollection of HPL gas purchases that took place over 20 years ago. See PX 2 at 23 (Buie report) ("Even though I wrote many of the contracts and was familiar with some of the delivery points, I wanted to review the contract files to refresh my recollection to be certain."). Given that the completeness of the HPL contract files in PX 14a and PX 14b is unproven, Mr. Buie's usage of those contract files, to bolster his "recollection" that the gas producers in question did *not* exercise their reserved processing rights in 1975, necessarily relies upon the same meritless negative inference that we reject herein, *supra*. Therefore, the court finds that the probative value of Mr. Buie's alleged personal recollection of such matters is, at most, insignificant and conjectural.

In sum, with respect to the 1975 gas purchases that HPL and Lo-Vaca made from producers that had reserved processing rights, Messrs. Buie and Eakin failed to affirmatively establish that such transactions were purchases of raw gas. Consequently, for purposes of proving that the 319 intrastate transactions in controversy that involved reserved processing rights were, in fact, sales of raw, unprocessed gas, Exxon's case hinges totally upon its proposed negative inference, *i.e.*, that when a contract file in PX 14a or PX 14b contains no document showing that the producer exercised its processing rights in 1975, no such exercise occurred. However, the contract files in PX 14a and PX 14b cannot logically sustain that negative inference, inasmuch as the completeness of such contract files, here at bar, is unproven. Thus, given the foregoing, we hold that Exxon has failed, on the basis of such flawed proof, to make out a *prima facie* case that such processing rights, in connection with the 319 intrastate transactions in question, were unexercised in 1975.[(225)]

Exxon protests the court's refusal to accept its proposed negative inference, arguing that our ruling imposes "an unwarranted, unprecedented, and virtually insurmountable burden of proof on Exxon," with respect to the reserved processing rights issue.[(226)] We disagree. First, Exxon has the burden of affirmatively proving, by a preponderance of the evidence, each and every indispensable element of its case -- including a showing that each transaction in its proposed RMFP computation was, in fact, a sale of unprocessed gas. See, e.g., Transamerica, 902 F.2d at 1543 (delineating the taxpayer's burden of proof in a refund suit). Accordingly, our insistence that Exxon meet this burden is hardly "unwarranted."

Second, our refusal to accept Exxon's proposed negative inference is further grounded upon Exxon's failure to show that the disputed contract files (PX 14a and PX 14b) are sufficiently trustworthy to meet the requirements of Rule 803(7), *supra*, under which the court is permitted, but not required, to draw a negative inference from the absence of an entry in business records. Authoritative evidence treatises uniformly emphasize the importance of presenting the testimony of the custodian of the business records sought to be admitted, as the foundational prerequisite to the admission of such records under Rule 803 (7). See Weinstein & Berger, *supra*, § 803.12, at 803-84; Wright & Graham, *supra*, § 6758, at 393; Mueller & Kirkpatrick, *supra*, § 8.51, at 995. Thus, aided by learned counsel who are, of course, well versed in the law of evidence, Exxon cannot be heard to complain about an "unprecedented" burden of proof.

Third, Exxon's burden is not "virtually insurmountable," inasmuch as it demands nothing more than elementary foundational testimony from the custodians of the pipeline company contract files, *i.e.*, PX 14a and PX 14b, regarding the origin and completeness of those files. If counsel for Exxon elected not to put such custodians on the witness stand at trial, it is not the court's role in hindsight to override counsel's tactical judgment, nor to fill in any resultant gaps in Exxon's proof, to the obvious prejudice of the Government. Moreover, we cannot simply *assume* that presenting the testimony of those custodians, in order to establish the trustworthiness of the contract files in PX 14a and PX 14b, would have been a futile effort. Indeed, on this record, whether Exxon's burden is "virtually insurmountable" or not is a matter of pure conjecture, inasmuch as Exxon failed to lay *any* evidentiary foundation regarding the recordkeeping practices of the pipeline companies that were the source of the contract files in PX 14a and PX 14b.

Further, as to whether the gas producers in the 319 intrastate transactions in question exercised their reserved processing rights and sold processed gas in 1975, we note that Exxon's failure of proof, *supra*, is not total. Another source of such proof exists, albeit one that Exxon neglected in the presentation of its case at trial. Specifically, Exxon can demonstrate that a transaction in issue was a sale of raw, unprocessed gas, if the underlying contract file in PX 14a or PX 14b contains documentation that *affirmatively* establishes that the producer's reserved processing rights were unexercised in 1975. Therefore, as discussed below, the court gave due consideration to such documentation, where it exists, pursuant to our examination of the contract files in PX 14a and PX 14b, for the purpose of identifying transactions that qualify for inclusion in the RMFP computation.[(227)] We turn now to the task of selecting, from this record, a representative sample of qualifying transactions, from which Exxon's 1975 RMFP may properly be computed.

I. *Transactions Qualifying For Inclusion In The RMFP Computation*

1. *Background*

As explained above, of the 2,058 transactions presented in Exxon's RMFP study, only 603 of those transactions remain under consideration for inclusion in Exxon's 1975 RMFP computation. We categorize those 603 transactions, taking into account reservations of processing rights to the producer, where applicable, as follows:

Number of

Character of Transaction Transactions

De jure (interstate) Account 800 transactions 158[(228)]

De facto (intrastate) Account 800 transactions, 8

agreed by parties to qualify as wellhead sales

De facto (intrastate) Account 800 transactions, 4

agreed by parties to qualify as wellhead sales,

but involving reserved processing rights

Subtotal -- undisputed wellhead sales 170

De facto (intrastate) Account 800 transactions 307

De facto (intrastate) Account 800 transactions, 126[(229)]

involving reserved processing rights

Subtotal -- transactions unagreed by parties 433

Total transactions under consideration 603.

In narrowing the transactions under consideration, from 2,058 to 603 transactions, the foregoing discussion has addressed only two of the four pertinent activities which, if undertaken by the producer before sale, will disqualify a transaction from inclusion in the RMFP computation, *i.e.*, transportation of the gas a material distance away from the wellhead, and processing for the extraction of liquefiable hydrocarbons. See Exxon I, 88 F.3d at 976. We have not yet addressed the extent to which either compression or dehydration of the gas, prior to sale, affects the qualification of the 603 transactions under consideration. Inasmuch as the vast majority of the 603 transactions in question involved compression or dehydration, prior to sale,[(230)] the court basically has two alternatives. First, taking the narrow view, we could exclude *all* of the transactions tainted by compression or dehydration from the RMFP computation, in adherence to the precedents which instruct that compression or dehydration, prior to sale, are grounds for disqualification. See Exxon I, 88 F.3d at 978 (acknowledging that exclusion of transactions tainted by compression or dehydration was consistent with prior case law). As a consequence, the RMFP would be based upon a relatively minuscule sample of transactions.

In the alternative, we can augment the RMFP sample by adopting the "preferable" method enunciated in dicta in Exxon I, 88 F.3d at 977-78, with respect to compression and dehydration, so as to enlarge the number of transactions includible in the RMFP computation. Under the "preferable" method, following the view expressed by the Federal Circuit in Exxon I, compression and dehydration are not necessarily grounds for disqualification. Rather, it is "preferable" to "cleanse" otherwise tainted transactions, by subtracting the costs of compression and dehydration, as applicable, from the sale price of the gas, if such costs are determinable with reasonable accuracy on the basis of credible evidence in the record. Id. at 977-78. The Federal Circuit's stated rationale for the "preferable" method is "the goal of maximizing the number of transactions included" in the RMFP computation. Id.; see also Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 704 (noting that the RMFP sample should be "sufficiently large and diverse enough to discount variations and offset errors"). Thus, in deciding whether to adopt the "preferable" method, here at bar, this court must bear in mind that "larger sampling should provide greater assurance that the price derived is in fact *representative*." Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 (emphasis added), quoted with approval in Exxon I, 88 F.3d at 976.

Two factors convince us that the "preferable" method of computing the RMFP is the approach most suited to the unique facts of the case at bar. First, the "preferable" method yields a sample of transactions that is significantly larger -- and, therefore, demonstrably more "representative" -- than any alternate sample comprised exclusively of transactions that were untainted by compression or dehydration, and otherwise qualified for inclusion in the RMFP computation, *i.e.*, untainted by transportation or processing as well. Second, it is feasible to apply the "preferable" method, on this record, because the methodology outlined in the Mr. Platt's compression and dehydration cost study, prepared on Exxon's behalf, can be used, with minor adjustments, to derive reasonable approximations of the typical costs of compression and dehydration in the Texas Gulf Coast/East Texas region in 1975. Given the foregoing findings, both of which are addressed in greater detail below, we hold that it is more appropriate, on this record, to utilize the "preferable" method in the computation of Exxon's RMFP.

Our adoption of the "preferable" method is not utterly without precedent, as the Government maintains. The Government correctly points out that the Federal Circuit's statements regarding the "preferable" method in Exxon I, 88 F.3d at 977-78, were unnecessary to the holding in that case and, thus, are dicta not binding upon this court. See Smith v. Orr, 855 F.2d 1544, 1550 (Fed. Cir. 1988) ("[I]t is well established that a general expression in an opinion, which expression is not essential to the disposition of the case, does not control a judgment in a subsequent proceeding."); In re McGrew, 120 F.3d 1236, 1238-39 (Fed. Cir. 1997) (to same effect) (citing King v. Erickson, 89 F.3d 1575, 1581 (Fed. Cir. 1996); United States v. Crawley, 837 F.2d 291 (7th Cir. 1988)). However, we disagree with the contention that the analysis ends with the recognition that such statements were dicta. On the contrary, at a minimum, we are constrained to view our superior court's remarks concerning the "preferable" method as being well-considered and instructive.[(231)] The end result of the RMFP computation is a reasonable approximation of the representative wellhead price of raw gas, *i.e.*, unprocessed, uncompressed, undehydrated gas. Exxon I, 88 F.3d at 976; Hugoton I, 161 Ct. Cl. at 280-81, 315 F.2d at 871-72. Logically, and in fact, there is no substantive difference between computing the representative wellhead price of raw gas directly, from a sample of transactions that are completely untainted by any compression or dehydration, or indirectly, by reference to a sample of tainted transactions that have been sanitized, under the "preferable" method, by subtracting any value added by compression or dehydration from the sale price of the gas. In either case, done correctly, the end result is substantially the same -- the representative wellhead price of raw gas -- as the Federal Circuit acknowledged in enunciating the "preferable" method in Exxon I, 88 F.3d at 977-78.

Moreover, we are of the opinion that authority for the "preferable" method can also be found in the Court of Claims' holding with respect to the Howell Field controversy in Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718. In Panhandle, as noted above, the Court of Claims found that the only wellhead sale of comparable gas in the Howell Field, on which the taxpayer's RMFP might be based, was the taxpayer's own sale of a portion of the gas produced by its McPherson No. 1-35 well, at a price of $0.325/Mcf. Panhandle, 187 Ct. Cl. at 170-71; 408 F.2d at 715-16. Given that finding, the Panhandle court observed that "a good case has been made for the court to determine that the representative market or field price of plaintiff's entire production from the Howell Field in 1952 was 32½¢ per MCF." Id. at 171, 408 F.2d at 716. However, the taxpayer sold the remainder of its gas from the McPherson No. 1-35 well, plus all of its gas production from another 13 wells in the Howell Field, under the same contract and at the same $0.325/Mcf price, at remote delivery points located some 30 to 40 miles away. Id. at 162; 408 F.2d at 710-711. Thus, with respect to the gas sold at the remote delivery points, the Court of Claims refused to hold that the putative wellhead price of $0.325/Mcf, established by reference to the taxpayer's sale of gas near the wellhead of its McPherson No. 1-35 well, was the RMFP. Instead, the court held that the taxpayer's cost of transporting its gas to the remote delivery points, stipulated at $0.035/Mcf, "should be deducted from the 32½¢ per MCF sales price of such gas, . . . resulting in a price of 29¢ per MCF which shall be used with respect to this production," *i.e.*, as the depletable gross income from the property. Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718.

We think that Panhandle's holding as to the Howell Field controversy is indistinguishable, in substance, from the "preferable" method later enunciated in Exxon I, 88 F.3d at 977-78. Specifically, the Court of Claims: (i) took a transaction that would otherwise have qualified as a wellhead sale (*i.e.*, the gas sold near the taxpayer's McPherson No. 1-35 well), but for the fact that the sale price of the gas was tainted by transportation costs; (ii) cured the tainted sale price by subtracting such transportation costs; and (iii) used that adjusted sale price to compute the depletable gross income from the property for the taxpayer's *other* sales of the Howell Field gas, made after the gas had been transported away from the wellheads. Consistent with the foregoing, in Exxon I, the Federal Circuit expressly noted that Panhandle is supportive of the "preferable" method. See Exxon I, 88 F.3d at 978 (citing Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718).

Further, in Panhandle, the Court of Claims acknowledged the conflict between "strict compliance with the doctrine of the Hugoton and Shamrock cases," *i.e.*, the established methodology of computing an RMFP solely on the basis of true wellhead sales of raw gas, and the fact that a mechanistic application of the RMFP method would, given the circumstances of the Howell Field controversy, "produce a price that could not be reasonably and realistically considered *representative* of [the taxpayer's] economic situation." Panhandle, 187 Ct. Cl. at 171, 408 F.2d at 715-16 (emphasis in original) (citing Hugoton II, 172 Ct. Cl. 444, 349 F.2d 418; Hugoton I, 161 Ct. Cl. 274, 315 F.2d 868; Shamrock, 35 T.C. 979). In resolving that conflict, the Court of Claims stated as follows:

[W]e read [Hugoton II] . . . to mean that the applicable regulation requires the use of a "representative market or field price," *if* an acceptable price of such nature can be established. Neither the court's decision in [the Hugoton II] case nor the regulation requires the impossible, i.e., the use of a price that cannot be determined *representative*, or as precluding us from applying some other formula that produces a fair result.

Panhandle, 187 Ct. Cl. at 174, 408 F.2d at 718 (emphasis in original) (citing Hugoton II, 172 Ct. Cl. at 459, 349 F.2d at 427); Treas. Reg. 118 § 39.23(m)-1(e)(1) (1952) (the substantively identical precursor to Treas. Reg. § 1.613-3(a)).

Here at bar, we are faced with a similarly difficult choice. On the one hand, the court could attempt to compute an RMFP on the basis of transactions that are untainted by compression or dehydration, but too few in number to give reasonable assurance that the resultant weighted-average price is realistically *representative* of the wellhead price of raw gas in the Texas Gulf Coast/East Texas region in 1975. On the other hand, the court can adopt the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78, so as to base the RMFP computation upon a substantially larger sample of transactions. Given the foregoing alternatives, we choose the "preferable" method, on the ground that a larger sample of transactions "should provide greater assurance that the price derived is in fact *representative*." Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 (emphasis added), quoted with approval in Exxon I, 88 F.3d at 976.(232) Thus, in addition to the handful of wellhead sales that are untainted by compression and dehydration, the court's RMFP sample shall include any transaction that otherwise qualifies as a wellhead sale of raw gas, but for the fact that the gas was compressed or dehydrated before sale, and for which the adjustments required to eliminate the value added by such compression or dehydration are determinable, on this record, with reasonable certainty.

We now turn to the selection of a representative sample of transactions on which Exxon's RMFP computation shall be based. As discussed above, the parties agree that of the 603 transactions that remain under consideration, 170 such transactions qualify for inclusion in the RMFP computation, consisting of 158 *de jure* (interstate) Account 800 transactions and 12 *de facto* (intrastate) Account 800 transactions. Therefore, the focus of the court's inquiry is upon the 433 *de facto* (intrastate) Account 800 transactions that are unagreed. Given our adoption of the "preferable" method with respect to the post-extraction activities of compression and dehydration, *supra*, the following analysis proceeds in three steps. First, we shall identify which of the 433 controverted intrastate transactions qualify for inclusion in the RMFP computation, in terms of whether the gas was, in fact, sold in the immediate vicinity of the well and without having been processed for the extraction of liquefiable hydrocarbons. Transactions satisfying those two conditions will be included, along with the 170 undisputed wellhead sales, *supra*, in the court's RMFP sample. Second, the court shall compare its RMFP sample with the alternative RMFP samples advocated by each of the parties, so as to demonstrate that our RMFP sample is the most "representative" sample of transactions that is adequately supported by the record. Lastly, with respect to those transactions in which the gas was compressed or dehydrated, prior to sale, we shall determine appropriate deductions for the costs of such compression or dehydration, as applicable, in accordance with the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78.

2. *Selection Of The RMFP Sample*

As explained above, in determining that the 433 intrastate transactions in dispute qualified for inclusion in its RMFP study, Exxon relied upon two flawed criteria. First, relative to the issue of transportation, Exxon relied upon its overbroad on-the-lease criterion, under which a qualifying wellhead sale would include any sale occurring at a delivery point located anywhere within the producer's "lease," expansively defined by Exxon to include an aggregation of multiple common-law oil and gas leases, irrespective of the size of the acreage encompassed therein, and without regard to the actual distance between the wellhead and the delivery point. Second, regarding the issue of processing for the extraction of liquefiable hydrocarbons, Exxon relied upon its untenable proposed negative inference, *i.e.*, that where a gas purchase contract in issue reserved to the producer the right to process its gas before delivery, and the related contract file in PX 14a or PX 14b gives no affirmative indication that the producer had exercised such reserved processing rights as of 1975, the producer was, in fact, selling unprocessed gas in 1975. However, the mere fact that Exxon's RMFP study rests upon invalid premises does not inevitably imply a total failure of proof as to the RMFP. On the contrary, we must be mindful that in Exxon I, the Federal Circuit held that the Court of Federal Claims committed reversible error "by truncating its RMFP analysis thus not reaching the issue of whether Exxon's [1974 RMFP] study contained *any* valid transactions from which an RMFP could be determined." Exxon I, 88 F.3d at 979 (emphasis added). Exxon I unequivocally instructs that we must closely scrutinize the record, here at bar, in order to determine whether there is *any* competent evidence of sales of raw gas in the immediate vicinity of the well, within the Texas Gulf Coast/East Texas region in 1975, from which an RMFP can be calculated. Thus, with respect to the qualification of the 433 intrastate transactions presently under consideration, for inclusion in the RMFP computation, Exxon I compels us to seek such evidence in the underlying pipeline company gas purchase contract files in PX 14a and PX 14b.

On the other hand, this court must acknowledge the evident impracticability of replicating, even if only in substantial part, the many thousands of hours of work that Exxon's experts put into reviewing the 300,000 pages of contract files in PX 14a and PX 14b,[(233)] for the purpose of selecting the transactions included in Exxon's RMFP study. Moreover, hypertechnical precision has never been the aim of the RMFP computation. Rather, the RMFP is merely a reasonable approximation of the representative price that the Exxon gas production in issue would have sold for in 1975, had Exxon marketed such gas in the immediate vicinity of the related wells. Hugoton I, 161 Ct. Cl. at 280-81, 315 F.2d at 871-72. See also Exxon I, 88 F.3d at 976 ("[T]he RMFP is employed as an inexact, simplified means of calculating an integrated producer's [percentage] depletion deduction."). Accordingly, given the characteristic inexactitude of the RMFP computation, we do not seek a perfectly "representative" sample of transactions. Indeed, to attempt such a determination, on this record, would be to pursue an unattainable ideal. Instead, we seek no more than "a *fair* selection of contracts," in effect within the Texas Gulf Coast/East Texas region during 1975, for the sale of raw gas in the immediate vicinity of the well. Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 (emphasis added).

With the foregoing considerations in mind, we have noted that the RMFP is a *volume*-weighted average price. Exxon I, 88 F.3d at 976, 979 & n.9; Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877. Therefore, relative to the 433 *de facto* (intrastate) Account 800 transactions in issue, our examination of the contract files in PX 14a and PX 14b emphasized transactions that involved large volumes of gas, because such large-volume transactions exert the greatest influence upon the RMFP. Specifically, the court examined the contract file, if available in PX 14a or PX 14b, relating to every such intrastate transaction, or group of connected transactions, involving the sale of at least 1,000,000 Mcf (one Bcf) of natural gas during the year 1975.[(234)] Such large-volume transactions were not, of course, the exclusive focus of our inquiry. However, given the limited time and resources that could reasonably be devoted to reviewing tens of thousands of pages of contract files, the court felt constrained to follow an approach calculated to safeguard against the possibility that the erroneous inclusion or exclusion of a very large transaction might cause a material distortion of the RMFP computation.

Of the 130 *de facto* (intrastate) Account 800 transactions in which processing rights were contractually reserved to the producer, *supra*, the court examined the contract files in PX 14a and PX 14b in connection with roughly 50 of such transactions. Our inquiry followed a simple guideline. Where a document in the contract file affirmatively indicated that the producer did *not* exercise its processing rights in 1975, the court concluded that the producer had, in fact, sold unprocessed gas.[(235)] Conversely, if the contract file contained no documentation from which it could be reasonably inferred that the producer had declined to exercise its processing rights in 1975, the transaction was disqualified from inclusion in the RMFP computation. Pursuant to the foregoing investigation, the court identified 18 *de facto* Account 800 transactions in Exxon's RMFP study, for which the related contract files affirmatively establish, with reasonable certainty, that the producers in question sold unprocessed gas in 1975.[(236)] As to the other 112 such transactions involving reserved processing rights, we hold that Exxon has failed to establish that said transactions were wellhead sales of raw, unprocessed gas that are properly includible in the RMFP computation.[(237)]

We turn now to the issue -- whether, in each of the 433 *de facto* (intrastate) Account 800 transactions under consideration, the producer added material value to the gas by transporting it away from the wellhead before sale.[(238)] As discussed above, a wellhead sale qualifying for inclusion in the RMFP computation must occur "on the premises," meaning that the point of delivery to the purchaser is located "in the immediate vicinity of the well." Treas. Reg. § 1.613-3(a). In other words, the delivery point must be "near the wellhead." Panhandle, 187 Ct. Cl. at 137, 162, 163, 172, 175, 408 F.2d at 696, 710, 711, 716, 717, 718. The foregoing standard plainly suggests, therefore, that the qualification of a transaction for inclusion in the RMFP computation hinges upon the physical proximity of the delivery point to the wellhead. Yet, on this record, the court finds itself unable to sharply define, due to the want of obligatory precedent, either "the immediate vicinity of the well," or the phrase "near the wellhead," in terms of any fixed measure of linear distance from the wellhead.

None of Exxon's experts were able to so define, in terms of a precise distance, what "the immediate vicinity of the well" is. Rather, Messrs. Ellis, Buie, and Eakin consistently expressed the view that "the immediate vicinity of the well" is a relative term that embraces no objective criterion of distance.[(239)] Conversely, Messrs. Nicol, Brown, Martin, and Robles, for the Government, uniformly opined that a transaction cannot qualify as a sale in "the immediate vicinity of the well" unless the delivery point is located not more than 500 feet from the well. However, the Government's 500-foot criterion finds no support in any legal pronouncement, authoritative treatise, or industry literature.[(240)] In fact, that 500-foot criterion is evidently nothing more than the product of an informal consensus reached over dinner one evening by the Government.

In any event, transportation of the gas away from the wellhead, prior to sale, is grounds for disqualifying a transaction from inclusion in the RMFP computation only if such transportation adds material *value* to the gas. Cannelton, 364 U.S. at 86; Exxon I, 88 F.3d at 975-76, 977-78; Panhandle, 187 Ct. Cl. at 143-44, 408 F.2d at 700; Hugoton II, 172 Ct. Cl. at 455-56, 349 F.2d at 425; Hugoton I, 161 Ct. Cl. at 277, 315 F.2d at 869. In quantifying the cost of such transportation, the physical proximity of the delivery point to the wellhead is an important consideration, insofar as it determines the length of the requisite gathering line; but distance is hardly the exclusive consideration. The cost of laying a gathering line over a given distance can vary significantly, depending upon the character of the terrain in the locality of the well, soil conditions, and the presence of obstacles, *i.e*., railroad tracks, highways, bodies of water, etc. Another pertinent variable is the productive capacity of the well, in that the per-Mcf cost of transporting gas a given distance away from the well decreases as the volume of gas produced by such well increases. This is so because, as explained in conjunction with the gas comparability issue, *supra*, in the case of a highly-prolific well situated atop a very large reserve of gas, the cost of laying a gathering line to transport the gas away from the well is spread over more units of gas production, relative to a marginally-productive well situated atop a small reserve, thereby lowering the per-Mcf transportation cost to the producer. See Hugoton I, 161 Ct. Cl. at 320, 315 F.2d at 894; Panhandle, 187 Ct. Cl. at 218-19. Thus, if the underlying reserve is sufficiently large, the producer can transport its gas more than 500 feet from the wellhead, prior to sale, without causing the per-Mcf price of such gas to reflect any *material* value added by transportation. Because the Government's 500-foot criterion fails to take any of the foregoing factors into account, the court is constrained to reject the Government's contention that "the immediate vicinity of the well" can *never* extend beyond 500 feet from the well.[(241)]

In short, neither litigant has proposed an acceptable, let alone obligatory, standard by which the court can identify intrastate transactions in which the gas was sold "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). Nonetheless, our examination of the pipeline company contract files in PX 14a and PX 14b disclosed a number of intrastate transactions for which the underlying contract unambiguously provided that the delivery point was located at or near the wellhead.[(242)] Such contract language, if uncontradicted by other evidence in the record, *i.e*., contrary documentation in the contract file, makes out a *prima facie* case that the transaction in question was a sale in the immediate vicinity of the well. In addition, it is well settled that a sale at the separator qualifies as a sale in the immediate vicinity of the well. Exxon I, 88 F.3d at 978; Panhandle, 187 Ct. Cl. at 151, 175, 227, 236, 408 F.2d at 704, 718. Therefore, the court also sought and identified transactions for which the related contract specified that the delivery point was located at the field separator appurtenant to each well.(243)

Moreover, our inquiry was not limited to the four corners of each intrastate gas purchase contract that we examined, but also addressed the extrinsic documentation in the pertinent contract file. In particular, the court sought documentation showing the identity of the party -- the producer or the purchaser -- that constructed the gathering line(s) required to transport the gas away from the wellhead(s). No value, of course, is added to the gas by transportation, prior to sale, if "the *purchaser* transports the gas away from the wellhead." Exxon I, 88 F.3d at 977 (emphasis in original). Thus, where correspondence, memoranda, work orders, or maps in the contract file showed that the purchaser did, in fact, construct a gathering line to take delivery of the gas at the wellhead or the appurtenant separator, the court included the transaction in the RMFP computation.(244) Conversely, if "the *producer* transports the gas away from the wellhead," prior to sale, the sale price of the gas "include[s] value added by transportation." Exxon I, 88 F.3d at 977 (emphasis in original). Accordingly, if the contract file indicated that the gas was sold and delivered at a common point, to which the producer was gathering the gas from multiple wells, or if the contract file was inconclusive as to whether any such gathering occurred before sale, the court disqualified the transaction.(245)

In this respect, the court gave particular consideration to certain multiple-well transactions reported as *de facto* Account 800 gas purchases in the 1975 GUD annual report of Lone Star Gas Company, the only significant Texas intrastate pipeline company to voluntarily utilize the NARUC Uniform System of Accounts in 1975. As explained above, such *de facto* Account 800 transactions are not rebuttably presumed to be gas purchases in the immediate vicinity of the well(s), as would be the case if Lone Star were an interstate pipeline company that had reported those transactions under Account 800 in an annual report (Form 2) required by law to be filed with the FPC. See Exxon I, 88 F.3d at 977-79 (limiting scope of Panhandle presumption to "FPC transactions" reported on "FPC forms"). However, we think the *de facto* Account 800 designations made in Lone Star's 1975 GUD annual report are nevertheless entitled to *some* probative weight, albeit not controlling weight, in determining whether Lone Star was, in fact, purchasing gas at the wellhead in the aforesaid multiple-well transactions. Consequently, the court examined the underlying contract files, in order to ascertain whether Lone Star had a rational basis for making such *de facto* Account 800 designations in its 1975 GUD annual report. Although our inquiry met with mixed success, the court found evidence in the contract files indicating that five such multiple-well transactions (G3776, G3781, G3783, G3810, and G3816) were sales at or near the wellhead(s), or the separator(s) appurtenant thereto.(246)

The court, on the other hand, assigns no probative weight whatsoever to the alleged, but unproven, classification of certain gas purchases under Account 41 in the internal accounting records of Lo-Vaca Gathering Company. Because Lo-Vaca purportedly based its Account 41 upon NARUC Account 800, as explained above, Exxon treated Lo-Vaca's alleged Account 41 gas purchases as *de facto* Account 800 transactions. On this record, however, we find that the reliability of Lo-Vaca's putative Account 41 designations is unproven. As noted in our discussion of the reserved processing rights issue, *supra*, Exxon produced no Lo-Vaca accounting records for the year 1975 that support its contention that Lo-Vaca categorized certain 1975 gas purchases under Account 41. Rather, Exxon sought to carry its burden by presenting Lo-Vaca accounting records for the year *1974*. Lo-Vaca's 1974 accounting records fail to establish that any of its 1975 gas purchases were made in the immediate vicinity of the producer's well(s), because those 1974 records fail to reflect any post-1974 events, such as changes in delivery points that arose in 1975 as a result of new wells being drilled and commencing production, or old wells depleting and ceasing production. The record shows, as noted above, that such occurrences were not unusual in

1975.[(247)] Indeed, the court found that a substantial portion of Lo-Vaca's 1975 gas purchases could not be traced back to Lo-Vaca's 1974 accounting records in any logical sense.[(248)] Thus, given the foregoing, we find that Lo-Vaca's 1974 Account 41 designations are entitled to zero probative weight for purposes of determining the character of Lo-Vaca's 1975 gas purchases.

Similarly unpersuasive, in the court's view, was Mr. Buie's testimony regarding certain gas purchases made in 1975 by Houston Pipe Line Company (HPL), his former employer. When asked whether he had any present recollection of any 1975 transactions in which HPL purchased gas in the immediate vicinity of the well, as contrasted with anywhere on the producer's leased acreage, Mr. Buie responded, "Oh, I can name a few." Tr. 449-50. Thereafter, the court directed Mr. Buie to review, during a lunch recess at trial, a tabulation of HPL's 1975 gas purchases presented in his report, and to put an identifying mark next to each transaction in which HPL purchased gas in the immediate vicinity of the well, in accordance with his purported recollection of such matters. Although Mr. Buie circled a number of transactions on the aforesaid tabulation, which was thereafter received in evidence as DX 45, he admitted that, in his judgement, those circled transactions were *not* gas purchases in the immediate vicinity of the well.[(249)] Having admitted his failure to comply with the court's directive, Mr. Buie went on to retract his earlier statement, *supra*, that he had a present recollection of 1975 gas purchases that HPL had made in the immediate vicinity of the well.[(250)] Further, Mr. Buie admitted that in deciding which transactions to circle on DX 45, he had acted upon instructions from counsel for Exxon, to the effect that he should circle any transaction for which the contract defined the delivery point as being "near" or "at" a well.[(251)] Thus, the record shows that Mr. Buie, in preparing DX 45, was guided not by his personal recollection of the transactions he circled, but by the language of the underlying contracts and the instructions he was given by Exxon.[(252)] Moreover, as to the handful of transactions listed in DX 45 that were individually and specifically addressed in Mr. Buie's testimony, it was evident that his recollection of such transactions was incomplete, doubtful, or even nonexistent, particularly insofar as his testimony relative to the physical proximity of the delivery points to the well(s) in question.[(253)] Consequently, for purposes of determining whether the 1975 HPL gas purchases listed in DX 45 occurred in the immediate vicinity of the well, the court finds that Mr. Buie's alleged personal "recollection" is entitled to no probative weight.[(254)]

As a result of our examination of a substantial number of the contract files in PX 14a and PX 14b, in connection with the 433 *de facto* (intrastate) Account 800 transactions in Exxon's RMFP study that remain under consideration, the court identified 22 additional intrastate transactions that qualify as sales of raw gas in the immediate vicinity of the well.[(255)] What is more, the court identified an additional qualifying intrastate transaction that is included in the Government's RMFP study (DX 5, SubX 2A), but not in Exxon's RMFP study, *i.e*., not among the aforesaid 433 transactions. In the subject transaction, Tejas Gas Corp. purchased gas from J.M. Huber Corp. during 1975, under a contract dated September 10, 1973, which provided that the delivery point was at "Seller's wellheads downstream from Seller's separation equipment." PX 14a at J000908. Based upon the foregoing contract language, our examination of the other documentation in the pertinent contract file, and Exxon's lack of opposition, the court concludes that the Tejas Gas/J.M. Huber transaction (which has no WGA ID number, due to its omission from Exxon's RMFP study) was a sale of raw gas in the immediate vicinity of the well.

In addition to the aforementioned 23 intrastate transactions, found by the court to be wellhead sales, and the 12 intrastate transactions conceded by the Government to be wellhead sales, *supra,* the court has determined that another 115 intrastate transactions, each involving a single well and a delivery point located relatively nearby on the producer's lease, also qualify as sales of raw gas in the immediate vicinity of the well. Whenever the delivery point pertains to a single well, this inevitably means that the producer is *not* adding value to its gas, prior to sale, by engaging in the practice of gathering gas from multiple wells to a *common* delivery point. Further, on this record, it is essentially undisputed that when a producer operates a single well and sells its gas on the lease, the producer normally sets its field separator on, or immediately adjacent to, the "well pad" for that well.[(256)] A well pad is an area of leveled ground covered with crushed rock, or another suitable surfacing material, that is constructed in order to provide an all-weather, erosion-resistant work surface on which to set the drilling rig and production equipment. Well pads are generally square or rectangular in shape and range from 150 to 300 feet on a side, depending upon the size of the equipment required to drill the well.[(257)] Similarly, in a single-well transaction, the pipeline company purchaser usually sets its custody meter, *i.e*., the physical point of delivery where title to the gas passes, on the well pad, or immediately adjacent thereto, a very short distance from the producer's separator.[(258)]

Economic considerations motivate the producer and the purchaser, in a single-well transaction, to locate the delivery point on, or next to, the producer's well pad, because moving the delivery point away from the well pad imposes additional costs upon both parties. Specifically, for the Government, Mr. Nicol testified persuasively that, if the delivery point is located away from the well pad, the producer must incur the cost of laying a gathering line to that delivery point, notwithstanding the fact that the producer has already incurred the cost of constructing a well pad that is otherwise suited to the installation of the purchaser's custody meter.[(259)] Moreover, although the producer has already built an access road leading to its well pad, Mr. Nicol pointed out, moving the delivery point away from the well pad compels the purchaser to incur the cost of building its own access road, in order to reach such a delivery point. Consequently, as a general rule, whenever the delivery point relates exclusively to a single well, and the producer and purchaser have agreed to locate that delivery point on the lease associated with such well, both parties are economically disadvantaged if the delivery point is located anywhere but on, or immediately adjacent to, the producer's well pad.[(260)]

Given all of the foregoing, in the case of a transaction involving only a single well and a delivery point located within the lease on which that well is located, one may reasonably infer, in the absence of proof to the contrary, that the delivery point was located on, or immediately adjacent to, the producer's well pad, meaning that the gas was sold in the immediate vicinity of the well, *i.e*., within a few hundred feet, as outlined by the boundaries of the well pad. Further, consistent with the aforesaid inference, upon evaluating a reasonable number of such single-well transactions, through an examination of the underlying contract files in PX 14a and PX 14b, the court determined that such transactions took place in the immediate vicinity of the well. Accordingly, inasmuch as the Government has gone forward with no pertinent countervailing evidence, we find that an additional 115 intrastate transactions in issue, each involving a single well and a delivery point located on the lease pertinent to that well, qualify as sales of raw gas in the immediate vicinity of the well.[(261)]

Upon making all of the aforementioned findings, the court has identified a sample of 308 transactions, in total, on which Exxon's RMFP for the taxable year 1975 shall be computed.

Appendix A, *infra*, tabulates these 308 transactions, which we summarize below, as follows:

Tentative

Volume-

Adjusted Weighted

Number Of Volume Of Sale Price Average

Transactions Gas (Mcf) Of Gas ($)[262] Price

Intrastate wellhead sales 150 56,022,014 66,600,861 $1.1888/Mcf

De jure (interstate) 158 56,172,842 11,307,230 0.2013/Mcf

Account 800 transactions ___ ___________ _________ ___________

Total -- tentative RMFP 308 112,194,856 77,908,091 $0.6944/Mcf.

The foregoing summary compels two observations. First, we think it to be patently clear that our 308-transaction RMFP sample is "sufficiently large and diverse enough to discount variations and offset errors." Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 704; see also Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 ("[L]arger sampling should provide greater assurance that the price derived is in fact representative."), quoted with approval in Exxon I, 88 F.3d at 976. Whether a sample of transactions is sufficiently large, for purposes of computing an RMFP, turns upon the number of transactions in that sample and, more importantly, given that the RMFP is a volume-weighted calculation, the volume of gas (Mcf) represented therein. Here at bar, from the standpoint of size, the sufficiency of our 308-transaction RMFP sample, representing over 112 million Mcf of gas, is indisputably demonstrated by comparison to the 1974 RMFP computation in Exxon I, which was based upon only 24 transactions involving roughly 29 million Mcf of gas. Exxon I, 88 F.3d at 979 & n.9. Moreover, in Exxon I, the Federal Circuit noted the propriety of calculating an RMFP on the basis of a sample containing as few as 20 transactions, or even one transaction. Id. at 978 (citing Hugoton II, 172 Ct. Cl. at 449, 349 F.2d at 420 (as to sufficiency of 20 transactions); Panhandle, 187 Ct. Cl. at 168-69, 408 F.2d at 714-15 (one transaction)).

Second, the 308 transactions in this court's RMFP sample illustrate the striking price disparity, already noted herein, between low-priced interstate gas ($0.2013/Mcf tentative average price) and high-priced intrastate gas ($1.1888/Mcf tentative average price) in the Texas Gulf Coast/East Texas region in 1975. Given such a price disparity, any significant bias in the RMFP sample, favoring either interstate gas or intrastate gas, in volumetric terms (*i.e.*, Mcf), would threaten to unfavorably distort the resultant volume-weighted RMFP calculation. No such likelihood of distortion is evident in the sample of 308 transactions that we have selected, because the respective volumes of low-priced interstate gas and high-priced intrastate gas represented therein are roughly equal. Thus, the court holds that, on this record, these 308 transactions constitute "a fair selection of contracts," as required by obligatory case law. Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877.

In reaching this conclusion, we read the controlling precedents to require that a truly "representative" sample of wellhead sales of comparable raw gas in the relevant market area (*i.e.*, the RMFP sample) must include volumes of interstate gas and intrastate gas in relative proportions that are reasonably reflective of the *actual* relative proportions of interstate and intrastate gas sold at the wellhead in that market area, unless the record shows that if the taxpayer were to sell its gas at the wellhead, its "mix" of interstate and intrastate sales would somehow deviate from that observed in the relevant market area. For example, in the Hugoton case, the taxpayer was an integrated producer that sold its natural gas, after transportation and processing, *solely* in *intra*state commerce. Hugoton II, 172 Ct. Cl. at 451, 349 F.2d at 421. Because there were no comparable *intra*state wellhead sales, but only *inter*state wellhead sales, in the relevant market area during the taxable years at issue, the taxpayer contended that the RMFP method was inapplicable. Id. at 451-52 & n.13, 349 F.2d at 421-22 & n.13. Firmly rejecting the taxpayer's "novel" argument, id. at 452, 349 F.2d at 422, the Hugoton II court noted that the record contained no evidence suggesting that if the taxpayer had sold its gas at the wellhead, it would have made such sales exclusively in *intra*state commerce. Id. at 457-58 & n.21, 349 F.2d at 426-27 & n.21. Therefore, the Court of Claims held that the RMFP had to be computed on the basis of comparable *inter*state wellhead sales, on the ground that the taxpayer had failed to demonstrate "that if it were free to sell its gas at the wellhead it would *not* be in competition with other producers of similar natural gas for *both* intrastate and interstate business." Id. at 457, 349 F.2d at 426 (emphasis added); see also id. at 460, 349 F.2d at 428.

The holding in Hugoton II was consistent with, and a natural consequence of, the Court of Claims' earlier decision in Hugoton I, wherein the taxpayer asserted that the RMFP for each tax year in issue should be based solely on gas purchase contracts entered into within that same year. According to the taxpayer, such "new" contracts most closely reflected the prevailing market price of natural gas, at the wellhead, during each such year. Conversely, argued the taxpayer, older contracts were indicative of market conditions prevailing in whatever prior year that such contracts were made and, therefore, the inclusion of such "old" contracts would distort the RMFP. Hugoton I, 161 Ct. Cl. at 288-89, 315 F.2d at 875-76. In essence, the taxpayer sought to take advantage of the pricing disparity between higher-priced new contracts and lower-priced old contracts, by excluding the latter from the RMFP computation.

Needless to say, the Court of Claims refused to entertain such a blatantly self-serving argument. In response to the taxpayer's contention that the inclusion of old contracts in the computation would distort the RMFP, the court stated:

Plaintiff points out that contracts for the sale of gas now generally include escalator clauses, providing for price increases to correspond with current market price increases. But the existence of these clauses does not indicate that the Government's averaging method [*i.e.*, an RMFP computed as a volume-weighted average price] saddles plaintiff with archaic contract prices which no longer govern. The effect of the escalator clauses will be taken into account in computing the price obtained under the particular contract for the tax year in question. Contracts entered far in the past and without such clauses will of course tend to reduce the representative price; but we see no basis for concluding that because particular contracts were unfavorable to the seller they should not be included in the computations.

Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 876-77. The Court of Claims reasoned, further, that "although the *market value* of gas at the wellhead is the amount that could be obtained for it under a new contract at any given time, the *representative price* is the price which is in fact being obtained under all existing comparable contracts." Id. at 284, 315 F.2d at 874 (emphasis in original). Thus, having so distinguished a "representative price" from the current market price of natural gas, the court held that the RMFP for each tax year must be calculated on the basis of "a fair selection of contracts in effect during each year," regardless of the year in which those contracts were entered into. Id. at 289, 315 F.2d at 877; see also id. at 279, 315 F.2d at 871. Moreover, several years thereafter, in the Panhandle case, the Court of Claims reaffirmed this principle, stating that "all the economic factors at work reflected in old, as well as new, contracts should be allowed full play. This tends to *achieve a balance* between old gas and new gas, *thereby making the price more representative* by avoiding a balance of either type of gas." Panhandle, 187 Ct. Cl. at 157, 408 F.2d at 708 (emphasis added) (citing Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 876-77).

As applied to the case at bar, we construe the holdings in the Hugoton case, *supra*, to stand for the self-evident and sensible principle that, in determining whether a proposed RMFP is based upon a "representative" sample of transactions, the court should consider whether that sample of transactions is reasonably reflective of the actual economic conditions in the underlying marketplace. What is more, the price disparity addressed in the Hugoton I decision -- between old and new contracts -- and the price disparity noted in the case at bar -- between interstate and intrastate gas -- present a compelling analogy. Indeed, the price disparity at issue in Hugoton I, is far surpassed by the magnitude of the price disparity between interstate and intrastate gas in the Texas Gulf Coast/East Texas region in 1975,[(263)] due to the sharp upswing in intrastate gas prices during the 1970s, suggesting an even greater need, here at bar, to safeguard against potential distortions of the RMFP calculation. Accordingly, in determining whether the 308 transactions we have selected constitute a suitably "representative" sample, the court must consider whether the volume-weighted mix of interstate and intrastate wellhead sales included therein is reasonably comparable to the actual mix of interstate and intrastate wellhead sales in the Texas Gulf Coast/East Texas region in 1975. See Hugoton II, 172 Ct. Cl. at 452 n.13, 349 F.2d at 422 n.13 (findings as to relative incidence of interstate and intrastate sales in taxpayer's market area).

However, inasmuch as neither party has attempted to establish the respective volumes of gas sold in the interstate and intrastate markets, at the wellhead, in the Texas Gulf Coast/East Texas region during 1975, the court is unable to make any conclusive findings in this respect.[(264)] Consequently, on this record, we are constrained to conclude that the 308 transactions we have selected, representing roughly equal volumes of interstate gas and intrastate gas, are reasonably reflective of the actual volumetric proportions of interstate and intrastate gas sold at the wellhead in the Texas Gulf Coast/East Texas region in 1975. By default, absent any evidence to the contrary, a presumption that the RMFP computation should accord roughly equal weight to low-priced interstate gas and high-priced intrastate gas is the most prudent, conservative, and defensible approach the court can adopt, insofar as that presumption is undeniably neutral and not demonstrably prejudicial to either litigant. Further, having failed to present any probative evidence suggesting that, as of 1975, wellhead sales in the Texas Gulf Coast/East Texas region occurred predominantly in either the interstate market or the intrastate market, neither party can credibly maintain that the RMFP computation should be materially biased in favor of either interstate gas (the Government's preference) or intrastate gas (Exxon's preference). See Hugoton II, 172 Ct. Cl. at 457-58 & n.21, 460, 349 F.2d at 426-27 & n.21, 428. On the contrary, either party's objection to a roughly equal weighting of interstate and intrastate gas must, on this record, be disregarded as a hospitable, self-serving attempt to "pack" the RMFP sample with whichever type of gas is favorable to that party's cause.

Therefore, for the reasons stated above, the court holds that the 308 transactions we have objectively selected for inclusion in the RMFP computation constitute "a fair selection of contracts," Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877, that is reasonably representative of the market for raw natural gas, at the wellhead, in the Texas Gulf Coast/East Texas region during 1975. We turn now to consider whether any alternate sample of transactions, shown by the parties on this record to be sales of raw gas in the immediate vicinity of the well, is more "representative" than the 308-transaction RMFP sample we have chosen.

3. *Comparison Of The Court's RMFP Sample To Alternate Samples*

As discussed above, Exxon has presented five, and the Government three, RMFP samples for the court's consideration. Three of Exxon's proposed RMFP samples, *i.e.*, its 2,058-transaction primary sample (PX 6, SubX G), and its 288-transaction and 56-transaction subsamples (PX 6, SubX E, F), we have already rejected, *supra*, due to Exxon's failure to prove that many of the transactions included therein were sales of raw, unprocessed gas "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a). In addition, we have rejected all three of the Government's proposed RMFP samples (DX 5 at

13-17), which presume the entire State of Texas to be the relevant market area, due to: (i) the Government's failure to present a statewide gas comparability study; and (ii) its failure to demonstrate that the entire State of Texas was the relevant market area, for purposes of computing Exxon's RMFP for the taxable year 1975.

Moreover, even assuming that the parties had overcome their respective failures of proof with respect to the aforesaid six proposed RMFP samples, none of those six samples could, on this record, be fairly deemed more "representative" than the 308-transaction RMFP sample that the court has selected. All three of the Government's proposed RMFP samples are so grossly and unjustifiably biased in favor of low-priced *inter*state gas as to warrant summary rejection. Specifically, in volumetric terms (Mcf), interstate gas constitutes over 99% of the gas represented in two of the Government's proposed RMFP samples, and over 95% of the gas in the third.[(265)] It is this bias in favor of interstate gas, and no other reason, that causes the Government's proposed computations of the 1975 RMFP to yield values ranging from approximately $0.34/Mcf to $0.36/Mcf -- a range of values that falls *below* the 1974 RMFP of $0.39/Mcf. Exxon I, 88 F.3d at 979. Given the incontrovertible continuing upward trend of natural gas prices during 1975, coupled with the Government's failure to identify any economic forces in the Texas natural gas industry that would cause the RMFP to *fall*, as between 1974 and 1975, the Government's proposed RMFP computations are plainly the end products of a transparent effort to "stack" the RMFP sample by unduly skewing the calculation toward low-priced interstate gas.

The Government, of course, is not alone in attempting to favorably influence the RMFP computation, inasmuch as all three of Exxon's proposed RMFP samples that we have addressed and rejected herein, *supra*, manifest a distinct bias in favor of high-priced *intra*state gas. Volumetrically, intrastate gas constitutes over 61% of the gas represented in Exxon's primary 2,058-transaction RMFP sample, over 65% of the gas in Exxon's 288-transaction subsample, and nearly 78% of the gas in Exxon's 56-transaction subsample.[(266)] This pronounced bias in favor of high-priced intrastate gas explains why the aforementioned three proposed RMFP samples produce values ($0.7645/Mcf, $0.8203/Mcf, and $0.7783/Mcf, respectively) that are well in excess of the $0.6944 tentative RMFP that we have computed, *supra*, on the basis of 308 transactions that represent roughly equal volumes of interstate and intrastate gas.[(267)]

Further, Exxon's claim that the RMFP computation should favor high-priced intrastate gas, but neglect low-priced interstate gas, cannot be sustained unless Exxon meets its burden of establishing a sound factual justification for this "alleged distinction between interstate gas and intrastate gas." Hugoton II, 172 Ct. Cl. at 458 n.21, 349 F.2d at 426 n.21. Yet, notwithstanding its tacit contention that the RMFP computation should be materially biased in favor of intrastate gas, Exxon has presented absolutely *no* evidence tending to show that any of its three proposed RMFP samples, *supra*, is reasonably "representative" of the actual relative proportions, in volumetric terms, of interstate and intrastate gas sold at the wellhead in the Texas Gulf Coast/East Texas region during 1975. Nor is there any way, on this record, to verify that Exxon's 2,058-transaction proposed RMFP sample and, by necessary implication, the 288-transaction and 56-transaction subsamples thereof, were not hospitably crafted to bring about the result that Exxon desires -- an RMFP in the range of 76¢ to 82¢ per Mcf -- by assigning undue weight to high-priced intrastate transactions.[(268)] Thus, even assuming that the aforesaid three Exxon samples were not invalidated by the inclusion of numerous non-qualified transactions therein, we nevertheless would be constrained to view such samples as evidence of Exxon's self-serving efforts to gratuitously "tilt" the RMFP calculation to its own favor.

In addition to the foregoing, Exxon has proposed two additional RMFP samples for the court's consideration: (i) a so-called "pristine" RMFP sample; and (ii) a sample of transactions relating to contracts that allegedly qualify as "fixed contracts" under § 613A(b)(1)(B). Exxon's "pristine" RMFP sample consists of 22 transactions that purport to be sales of uncompressed, undehydrated, unprocessed gas within 500 feet of the wellhead, thereby satisfying the Government's criteria for a qualifying wellhead sale. However, even assuming, *arguendo*, that all 22 transactions in Exxon's "pristine" RMFP sample qualified as sales of raw gas in the immediate vicinity of the well,[(269)] those 22 transactions could not plausibly be deemed to be a more "representative" sample than the 308 transactions we have studiously selected. Assuredly, like the court's 308-transaction RMFP sample, the 22 transactions in Exxon's "pristine" sample are fairly balanced between low-priced interstate gas (11 transactions involving 4,314,779 Mcf) and high-priced intrastate gas (11 transactions involving 4,162,343 Mcf). Yet, the court's 308-transaction RMFP sample undeniably presents a more comprehensive cross-section of wellhead sales in the Texas Gulf Coast/East Texas region during 1975. Whereas the 22 transactions in Exxon's "pristine" RMFP sample involved only five buyers and 17 sellers of natural gas, the 308 transactions that we have selected involved 15 buyers and dozens of different sellers, thereby addressing a broader, more representative range of participants in the relevant marketplace. Moreover, the 112,194,856 Mcf of gas represented in the court's 308-transaction RMFP sample dwarfs the minuscule 8,477,122 Mcf represented in Exxon's "pristine" RMFP sample. Therefore, as compared to Exxon's so-called "pristine" RMFP sample, our larger sample clearly "provide[s] greater assurance that the price derived is in fact representative." Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877, quoted with approval in Exxon I, 88 F.3d at 976.[(270)]

Turning to Exxon's 460-transaction "fixed contract" sample (PX 38, SubX C), the court is constrained to hold that said sample fails to qualify as a "representative" sample of transactions, given our previous findings, on the grounds articulated herein, *supra*, that many of those 460 transactions fail to qualify as wellhead sales of raw gas. For the sake of completeness, we also note that Exxon presented this sample in response to the Government's contention that, as a matter of law, the RMFP sample should be restricted exclusively to wellhead sales of raw gas made under contracts that qualify as "fixed contracts" within the meaning of § 613A(b)(1)(B). As discussed above, the Code defines such a "fixed contract" as "a contract, in effect on February 1, 1975, . . . under which the price for such gas cannot be adjusted to reflect to any extent the increase in liabilities of the seller for tax under this chapter by reason of the repeal of percentage depletion." § 613A(b)(2)(A). The Government, of course, advances this argument in response to certain dicta in this court's opinion denying the Government's pre-trial summary judgment motion. See Exxon, 40 Fed. Cl. at 91-92. However, the Government disregards our *holding* in that opinion.

In denying the Government's summary judgment motion, we held that the RMFP method of determining the depletable "gross income from the property" under Treas. Reg. § 1.613-3(a), as interpreted and applied by the pertinent pre-1975 case law, culminating with Exxon I, 88 F.3d 968, must continue to govern post-1974 percentage depletion computations under the fixed contract exception of § 613A(b)(1)(B), absent a convincing demonstration that such an application of Treas. Reg. § 1.613-3(a) "produces results which are arbitrary, capricious, or manifestly contrary to the post-1974 statutory percentage depletion scheme." Exxon, 40 Fed. Cl. at 86 (citing Chevron, 467 U.S. at 844; Portland Cement, 450 U.S. at 169; Schuler, 109 F.3d at 755). Further, as to whether such an impermissible result would ensue from a straightforward, traditional application of the RMFP method under Treas. Reg. § 1.613-3(a), as construed under pre-1975 law, we held that genuine issues of material fact precluded summary judgment under RCFC 56. Exxon, 40 Fed. Cl. at 91. Specifically, on the undeveloped record then before the court, we were unable to determine whether an RMFP computed under the pre-1975 interpretation of Treas. Reg. § 1.613-3(a) "would upset the competitive balance that Congress sought to strike between integrated and nonintegrated producers in the 1975 Act." Id. at 92.

Moreover, even assuming that Treas. Reg. § 1.613-3(a), as construed under pre-1975 law, might conflict with the intent of Congress, as enunciated in § 613A, we expressed our doubt "that harmonizing Treas. Reg. § 1.613-3(a) with the post-1974 statutory percentage depletion scheme is an insurmountable task." Exxon, 40 Fed. Cl. at 91. *Solely* by way of illustrating the foregoing point, we suggested the possibility, *in dicta*, of computing an RMFP exclusively on the basis of a sample of transactions involving "fixed contracts" under § 613A(b)(1)(B). Id. at 91-92 & n.30. Upon further reflection, however, in light of the record accumulated at trial, the court concludes that such a departure from a straightforward, traditional application of Treas. Reg. § 1.613-3(a) is unwarranted. Binding precedents, decided under pre-1975 law, instruct that a "representative" RMFP sample must include *all* types of contracts -- old or new, interstate or intrastate, long-term or short-term, fixed-price or not -- so long as such contracts call for the sale of comparable raw gas at the wellhead in the taxpayer's market area. Hugoton I, 161 Ct. Cl. at 279, 284, 289, 315 F.2d at 871, 874, 876-77; Hugoton II, 172 Ct. Cl. at 452, 457-58, 460, 349 F.2d at 422, 426-27, 428; Panhandle, 187 Ct. Cl. at 157, 408 F.2d at 708; Exxon I, 88 F.3d at 975-76 & n.7. Therefore, were this court to limit the RMFP sample exclusively to transactions arising from "fixed contracts" under § 613A(b)(1)(B), as the Government urges, we would depart significantly from the aforesaid precedents.

On this record, we have no justification for doing so. At trial, the Government presented absolutely *no* credible evidence from which it might be reasonably inferred that when integrated natural gas producers, such as Exxon, claim a percentage depletion deduction pursuant to the post-1974 fixed contract exception, the pre-1975 RMFP methodology heretofore recognized in Exxon I and the other relevant precedents, *supra*, "systematically places nonintegrated producers at a competitive disadvantage." Exxon, 40 Fed. Cl. at 91. Absent any such proof, we have no basis for concluding that the RMFP method under Treas. Reg. § 1.613-3(a), as construed under pre-1975 law, conflicts with the post-1974 statutory percentage depletion scheme. Further, it cannot be denied that Treas. Reg. § 1.613-3(a) binds the Government no less than it does Exxon. Hugoton I, 161 Ct. Cl. at 280 n.14, 315 F.2d at 871 n.14. Consequently, to depart from a straightforward, traditional application of Treas. Reg. § 1.613-3(a), here at bar, by limiting the RMFP sample to transactions arising from "fixed contracts" under § 613A(b)(1)(B), would be unjustified and inappropriate. Thus, even assuming that all of the 460 transactions in Exxon's "fixed contract" sample qualified as wellhead sales of raw gas, we would be constrained to hold, as a matter of law, that said sample is not suitably "representative."

Given all of the foregoing, the court finds that neither party has presented a sample of transactions that plausibly can be deemed more "representative" than the 308-transaction RMFP sample we have chosen. Accordingly, with respect to Exxon's 1975 percentage depletion allowance for the gas well gas produced from the 369 Exxon properties in issue, representing 90.26% of the Exxon gas in controversy, in volumetric terms (Mcf),[(271)] we hold that the RMFP computation under Treas. Reg. § 1.613-3(a), on this record, must be based upon the 308 transactions listed in Appendix A, *infra*.

Having thus determined the identity of the 308 transactions on which the RMFP computation shall be based, we turn now to the determination of appropriate deductions for the costs of compression and dehydration, as applicable, from the sale price of the gas in those 308 transactions. As discussed above, it is not feasible, here at bar, to assemble a legitimately "representative" sample of transactions in which the sale price of the gas was completely untainted by compression or dehydration. In fact, of the 308 transactions in our RMFP sample, the court has determined that only 30 such transactions were free of compression and dehydration before sale. We think it self-evident that this subsample of 30 untainted transactions, involving the sale of no more than roughly 25 Bcf of gas, cannot credibly be deemed more "representative" than the 308 transactions we have selected, which involved the sale of over 112 Bcf.[(272)] Therefore, under the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78, the court shall cleanse the 308 transactions in our RMFP sample, where necessary, by deducting reasonable estimates of the applicable costs of compression and dehydration from the sale price of the gas. We turn first to the subject of compression.

4. *Adjustments For Costs Of Compression Prior To Sale*

For purposes of determining a reasonable approximation of the applicable costs of compression, the court essentially followed the methodology presented in the compression cost study that Mr. Platt prepared on Exxon's behalf.[(273)] Although, of course, the opinions of expert witnesses, if intrinsically unpersuasive, are not conclusive and binding on the court, Sternberger, 185 Cl. Ct. at 535-36, 401 F.2d at 1016, we adopted Mr. Platt's approach for two reasons. First, given his 35-plus years of experience as a petroleum engineer and his testimony at trial, it is evident that Mr. Platt has substantial experience with the design and installation of field compression systems. Further, Mr. Platt's assumptions and determinations regarding the factors that materially influence the cost of compression are, for the most part, amply supported by engineering treatises, government publications, or authoritative industry sources, pertinent excerpts of which are in the record. Second, although the Government's compression experts, Messrs. Nicol and Martin, disagreed with certain aspects of Mr. Platt's compression cost study, they failed to discredit Mr. Platt's overall approach. Moreover, Messrs. Nicol and Martin failed to present any alternative methodology of deriving a reasonable approximation of compression costs. At most, Messrs. Nicol and Martin showed that certain of the assumptions that underlie Mr. Platt's assumptions are insufficiently conservative, *i.e.*, tending potentially to understate the costs of compression and, thus, to overstate the RMFP. As explained below, the court found that it was feasible to make appropriate adjustments to Mr. Platt's assumptions, where necessary, in order to address the few substantive criticisms raised by the Government.

With respect to any transaction in issue, the compression cost determination requires a two-step analysis. First, one must determine whether the producer was required to compress its gas before sale. Second, if compression was required, prior to sale, the costs of such compression must be quantified. We address these two questions *seriatim*.

Natural gas, as with gaseous substances generally, flows naturally from a high pressure area to an area of lower pressure. Therefore, gas will flow from a producer's well into the purchaser's pipeline, without mechanical assistance, so long as the well produces gas at a pressure that *exceeds*, at least slightly, the operating pressure of the purchaser's pipeline. Conversely, where the well produces gas at a pressure that is less than the operating pressure of the purchaser's pipeline, compression is required. Where installed near the wellhead, field compression facilities in the Texas Gulf Coast/East Texas region, as of 1975, were predominantly reciprocating compressors, which use a reciprocating piston to compress the gas. Reciprocating compressors are typically powered by an internal combustion engine that is fueled by the natural gas produced by the appurtenant well(s).

Gas purchase contracts of the sort at issue here do not commonly state, in express terms, that one party or the other, *i.e.*, producer or purchasing pipeline company, is required to compress the gas if necessary. Rather, such contracts specify a maximum delivery pressure (MDP), which is the highest pressure at which the purchaser can require the producer to deliver gas. Stated differently, if the producer's well produces gas at a pressure equal to or exceeding the contractual MDP, the purchaser cannot require the producer to compress its gas. Consequently, for purposes of determining whether a producer was required to compress its gas, in order to effect delivery of the gas into the purchaser's pipeline, with respect to any well associated with a transaction in issue, Mr. Platt compared the 1975 flowing tubing pressure (FTP) of the well, as derived from the Dwights database, *supra*, with the MDP specified in the pertinent gas purchase contract, *i.e.*, in PX 14a or PX 14b.[(274)] If the FTP exceeded the MDP of the pipeline, Mr. Platt concluded that the producer did not compress its gas in 1975, because the well could flow gas into the purchaser's pipeline naturally, without compression. If, on the other hand, the MDP exceeded the FTP, Mr. Platt concluded that the producer was required to compress its gas before sale.

In making the foregoing determination, relative to each transaction in issue, Mr. Platt relied upon a conservative assumption -- that the purchaser's pipeline continuously operated, throughout all of 1975, at the MDP specified in the pertinent gas purchase contract. This assumption necessarily presumes that the producer was providing, *at all times*, the greatest amount of compression required, if any, to meet its contractual compression obligation and, therefore, incurring the maximum amount of compression costs. However, Mr. Platt pointed out, and it is apparent, that pipelines usually do not operate at full MDP 24 hours a day, 365 days a year.(275) Thus, the court finds that Mr. Platt's method of determining whether the producer was required to compress its gas, prior to sale, yields reasonable, conservative results. We find, further, based upon Mr. Platt's determinations, that 243 of the 308 transactions in our RMFP sample involved compression before sale.(276) Having made the foregoing findings, we turn now to address Mr. Platt's methodology for determining the applicable costs of such compression.

Mr. Platt's method of estimating the typical, or average, cost of field compression, *i.e.*, compression performed in the field by a gas producer, largely follows the methodology that the staff of the Federal Energy Regulatory Commission (FERC) developed in 1980, for purposes of determining the amount of the compression allowance that natural gas purchasers (*i.e.*, pipeline companies) were permitted to pay gas producers, pursuant to § 110 of the NGPA, 15 U.S.C. § 3320 (1978). See *Staff Report: Cost Analysis of Gathering and Compression and Recommendation of Related Allowances Under Section 110 of the Natural Gas Policy Act*,45 Fed. Reg. 84814, 84815-84820 (Dec. 16, 1980) (hereinafter, "FERC Staff Report"), reproduced at PX 5, SubX 15, part 1 (Platt report).(277) In the aforementioned compression cost study, FERC determined that three factors contribute to the cost of field compression: (i) the capital cost of the compression equipment; (ii) the costs of operating and maintaining the compressor; and (iii) fuel costs. FERC Staff Report, *supra*, 45 Fed. Reg. at 84815-16, 84819. Likewise, as discussed below, Mr. Platt's compression cost study addresses each of these three factors.

A determination of the typical cost of field compression must take into account the fact that, in order to increase the pressure of the gas to the desired level, compression frequently must take place in multiple "stages," or steps, as opposed to an unbroken single-stage process. The number of stages required is a function of: (i) the pressure at which the seller's well produces gas, *i.e.*, the flowing tubing pressure (FTP); (ii) the operating pressure of the purchaser's pipeline, assumed herein to be the contractually-specified MDP; and (iii) the compression ratio of the equipment used to compress the gas. For each stage of compression, the compression ratio is the ratio of the outlet pressure of the gas, *i.e.*, as it exits the compressor, to the inlet pressure of the gas, *i.e.*, as it enters the compressor.(278) Thus, if gas is compressed at a ratio of 3.5 to 1 per stage, and the producer's well produces gas at an FTP of 100 psi, one stage of compression will increase the pressure of the gas to 350 psi (100 psi x 3.5), and a second stage will increase the pressure to 1,225 psi (350 x 3.5).

As contrasted with the per-stage compression ratio, *supra*, the *overall* compression ratio is the ratio of the outlet pressure of the gas after the final required stage of compression, *i.e.*, the pressure required in order to effect delivery of the gas into the purchaser's pipeline (assumed herein to be the contractual MDP), to the inlet pressure of the gas prior to the initial stage of compression, *i.e.*, the FTP of the producer's well. For example, at a per-stage compression ratio of 3.5 to 1, if the well's FTP is 300 psi and the purchaser's pipeline pressure is 1,000 psi, only a single stage of compression is required in order to raise the pressure of the gas above the pipeline pressure, so as to permit the gas to flow into the pipeline (310 psi x 3.5 = 1,050 psi), and the overall compression ratio is 3.5 to 1. If, on the other hand, the well's FTP is 90 psi, then two stages of compression are required (90 x 3.5 x 3.5 = 1,102 psi), and the overall compression ratio is 12.25 (3.5 x 3.5). Thus, by knowing the overall compression ratio, which can be inferred from the differential between the FTP of the producer's well and the MDP of the purchaser's pipeline, and the per-stage compression ratio of the compressor, one can determine how many stages of compression are required.

For purposes of his compression cost study, Mr. Platt determined that a ratio of 3.5 to 1 is representative of the per-stage compression ratio of the reciprocating compressors typically utilized by gas producers in the Texas Gulf Coast/East Texas region in 1975. Mr. Platt's conclusion is consistent with FERC's final determination in 1983, pursuant to its study of field compression costs, that a per-stage compression ratio of 3.5 to 1 most closely reflects normal field compression practices in the natural gas industry.(279) In addition, a 3.5 to 1 ratio falls comfortably within the range of per-stage compression ratios prescribed by several natural gas engineering treatises that are reproduced, or excerpted in pertinent part, in the reports of Messrs. Platt and Pohler.(280) On this record, inasmuch as the Government presented no credible countervailing evidence, the court finds that a ratio of 3.5 to 1, as determined by Mr. Platt, is a reasonable approximation of the per-stage compression ratio of a typical field compressor.(281)

Given a per-stage compression ratio of 3.5 to 1, Mr. Platt determined that a 75 horsepower compressor is required to compress one MMcf of gas per day, relying upon a chart from a natural gas engineering treatise, reproduced in his report, that graphically portrays the mathematical relationship between the per-stage compression ratio and the requisite horsepower.(282) Based upon the foregoing, all of Mr. Platt's compression cost calculations assume that a 75-hp, one MMcf/day compressor was typical of the field compression facilities associated with the transactions in issue. According to Mr. Platt, this assumption is conservative, *i.e.*, tending to overstate the average cost of compression, in that it disregards the cost savings that result when the producer compresses volumes of gas exceeding one MMcf/day. Such cost savings arise from economies of scale, because the cost per horsepower of acquiring and installing a compressor decreases as the horsepower (*i.e.*, the capacity) of the compressor increases.

However, Mr. Martin, for the Government, challenged Mr. Platt's approach, on the ground that it fails to take into account the *dis*economies of scale associated with transactions involving *less* than one MMcf/day of gas production. Specifically, in his report, Mr. Martin contends that Mr. Platt's assumption that a typical field compressor handles one MMcf/day, as applied to the transactions represented in Exxon's RMFP sample, "is not appropriate since only 480 of the total 1,870 transactions potentially requiring compression have a compressed volume of 1,000 Mcf per day or more. For the other 1,390 transactions, the cost per Mcf would be higher if the actual compressed volumes were used in the calculation instead of the [assumed] 1,000 Mcf per day." DX 1 at 20. The gravamen of Mr. Martin's criticism is that, irrespective of the actual volume of gas being compressed, Mr. Platt assumed that the typical 75-hp field compressor *always* compresses gas at the rate of one MMcf/day. Therefore, in connection with transactions involving less than 365,000 Mcf of gas production during the year 1975 (*i.e.*, one MMcf/day annualized), Mr. Platt's assumption tends to *under*state the actual compression cost per horsepower and, ultimately, the compression cost per Mcf. This is so, as Mr. Platt admitted at trial (Tr. 2579), because the capital cost of the 75-hp compressor, in actuality, is spread over fewer units of gas than the one MMcf/day that such compressor has the capacity to handle.

However, of the total volume of gas represented in the 243 transactions in the court's RMFP sample that involved compression before sale (76,392,770 Mcf), approximately three-fourths of such gas (56,838,718 Mcf) was sold in transactions involving more than 365,000 Mcf, whereas only one-fourth of such gas (19,554,052 Mcf) was sold in transactions involving less than 365,000 Mcf. Therefore, given the foregoing, the transactions involving more than 365,000 Mcf exert a much greater influence upon the RMFP computation than the sub-365,000-Mcf transactions, because the RMFP is calculated as a volume-weighted average price. Exxon I, 88 F.3d at 976, 979. Moreover, as explained above, Mr. Platt's assumption of a 75-hp, one MMcf/day compressor tends to overstate the compression costs in connection with transactions involving more than 365,000 Mcf. Consequently, inasmuch as the transactions involving more than 365,000 Mcf predominate over the sub-365,000-Mcf transactions by a margin of three to one, in volumetric terms, it is evident that any understatement of the compression costs in connection with the sub-365,000-Mcf transactions is offset, if not substantially outweighed, by the overstatement of the compression costs with respect to the transactions involving more than 365,000 Mcf. Thus, as applied to the court's 308-transaction RMFP sample, for purposes of deriving a reasonable approximation of the applicable costs of compression, we find that Mr. Platt's assumption of a 75-hp, one MMcf/day compressor tends, *on the average*, to produce a conservative result, *i.e*., tending to overstate the capital cost of compression per Mcf.

Further, we take no issue with Mr. Platt's methodology of calculating a typical, or average, cost of compression, then extrapolating that average cost to each of the transactions in the RMFP sample that involved compression before sale. Such an approach finds precedent in the final compression cost allowance regulations promulgated by FERC in 1983, under § 110 of the NGPA, and in FERC's underlying compression cost study, prepared in 1980, the objective of which was to determine "generic" or "representative" allowances for the cost of compression, as distinguished from case-by-case compression cost determinations. See *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44495-96, 44501 (Sept. 27, 1983), codified at 18 C.F.R. chap. 1, § 271.1104(d)(1)(iv)(A) (1983); Order No. 94, *Order Amending Interim Regulations Under the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act*, 45 Fed. Reg. 53099, 53100, 53106, 53109 (July 25, 1980). What is more, like Mr. Platt, FERC based its generic compression horsepower and cost determinations upon an assumed average daily compressed volume of one MMcf. FERC Staff Report, *supra*, 45 Fed. Reg. at 84819-84820.

In addition, the Government failed to present any credible evidence, here at bar, tending to show that it is impracticable to derive a reasonable approximation of a typical, or average, cost of compression. Although Mr. Nicol opined that field compression involves too many variables for a single uniform formula to yield accurate results, and that compression experts do not rely upon industry averages to overcome this multiplicity of variables, he cited no authoritative works on the subject of natural gas compression, and submitted no compression cost study or calculations of his own, in support of his vague, conclusory assertion.(283) Accordingly, on this record, for purposes of determining the applicable costs of compression, relative to the 308 transactions in the court's RMFP sample, we hold that Exxon has sufficiently demonstrated that a typical field compression facility in the Texas Gulf Coast/East Texas region, as of 1975, consisted of a 75-hp reciprocating compressor, capable of handling one MMcf of gas per day, at a compression ratio of 3.5 to 1 per stage of compression.

Having concluded that a 75-hp reciprocating compressor typified the field compression facilities in use in the Texas Gulf Coast/East Texas region in 1975, Mr. Platt determined that the capital cost (*i.e*., cost to purchase) of such a compressor was $1,000 per horsepower, or $75,000. The foregoing cost determination is amply supported by the record, and was unchallenged by the Government at trial. Thereafter, in order to express the $75,000 capital cost of the compressor in per-Mcf terms, Mr. Platt utilized a discounted cash flow model to calculate the annual amount of capital recovery with respect to the compressor, *i.e*., an annual charge analogous to depreciation but adjusted for the time value of money, over an assumed useful life of 15 years.(284) In his DCF calculations, Mr. Platt used a discount rate of 8% per annum, which approximates the average prime rate charged by banks in 1975. While acknowledging that lenders take the risks associated with oil and gas field operations into account in setting loan terms, he nonetheless opined that the 8% prime rate reflects the appropriate cost of capital for a field compressor in 1975. As compared to an investment in a gas well, which presents the risk of sunk, unrecoverable costs if the well is unsuccessful or depletes prematurely, Mr. Platt asserted, a small field compressor (*i.e*., a 75-hp compressor) is a low-risk investment, because it can easily be moved and utilized at other locations, should the gas well cease production.

On the Government's behalf, Mr. Martin assailed Mr. Platt's 8% discount rate as being too low and, therefore, insufficiently reflective of the true risk associated with the acquisition and installation of a field compressor. The implication of setting the discount rate at too low a value, in Mr. Platt's DCF equation, is that the annual capital recovery charge is understated, which in turn causes the overall costs of compression to be understated. Mr. Martin pointed out that the risks associated with an investment in a field compressor include: (i) the risk of the compressor wearing out prematurely; (ii) the risk of an abrupt drop in energy prices, as in the mid-1980s, such that surplus field equipment like compressors wind up being sold for scrap; and (iii) the risk of the well depleting before the compressor has served its full useful life. What the existence of such risks implies, Mr. Martin explained, is that the 1975 cost of capital for a field compressor substantially exceeded the 8% prime rate. In Mr. Martin's view, a discount rate of 18% is required, representing the sum of the 8% average prime rate for 1975, a 2% premium to arrive at an assumed 10% cost of funds to a non-prime-rate borrower in 1975, and an assumed 8% risk premium associated with an investment in a field compressor.

We find Mr. Martin's view of the risks inherent in field compression more convincing than Mr. Platt's position. The risk of a premature breakdown, cited by Mr. Martin, exists in connection with most types of machinery, but is undoubtedly heightened when the equipment in question is deployed outdoors -- as with a field compressor -- and, thus, is constantly subjected to the elements. Further, the court is persuaded that lenders to the oil and gas industry do, in fact, take the risk of an abrupt downturn in energy prices into account, given Mr. Martin's uncontradicted testimony that he has experienced the effects of a rapid drop in energy prices firsthand, in the 1980s, and that he is personally aware of cases in which buyers of compressors or other field equipment failed to repay their loans.(285) As to the third risk factor that Mr. Martin identified in connection with an investment in a field compressor -- the risk of the well depleting before the compressor has served its full useful life -- the question is whether it is truly an easy matter, as Mr. Platt maintained, to redeploy a field compressor to another wellsite. Although Mr. Platt based his opinion as to the ready portability of field compressors upon his considerable personal experience as a petroleum engineer, there is no other evidence in the record to support that opinion. What is more, several maps in the record indicate that natural gas fields in the Texas Gulf Coast/East Texas region are frequently located in remote rural areas, far from any significant cities or towns. From the foregoing, one can reasonably infer that the redeployment of a field compressor across undeveloped tracts of land and over rural roads, where such exist, may often be a costly endeavor. Moreover, the remoteness of many gas fields suggests that a gas producer's field compressor makes rather poor collateral, from a lender's viewpoint, due to the difficulty of repossession, should the producer default on its loan.

In addition to the risk factors cited by Mr. Martin, the court notes that in 1981, in response to FERC's 1980 compression cost study, the major oil and gas companies, *Exxon included*, argued that "[t]he risk premium required for [field compression] operations is at least 6 to 7 points above the cost of essentially risk free investments." Phillips Petroleum Co. et al., *Joint Initial Comments of Indicated Producers*, at 22 (March 2, 1981), reproduced at PX 5, SubX 15, at 57. Given the foregoing, on this record, we find that a rate of 14%, representing a 6% risk premium over the 1975 average prime rate of 8%, is a reasonably conservative approximation of the 1975 cost of capital for a field compressor.(286) Further, upon substituting the rate of 14% for the 8% discount rate utilized in Mr. Platt's DCF equation, the court has determined that the annual capital cost recovery charge for a typical 75-hp field compressor, costing $75,000 and having a useful life of 15 years, increases from the sum of $8,760, as determined by Mr. Platt, to the sum of $12,211.

Turning to the second element of compression costs addressed in Mr. Platt's study, we note that Mr. Platt estimated the annual costs of operating and maintaining a typical 75-hp, one MMcf/day field compressor to be $4,500, which equates to 6% of the $75,000 capital cost of such a compressor. Here again, Mr. Platt followed the approach taken by FERC in its 1980 compression cost study, wherein FERC determined that the annual operating and maintenance costs for a 65-hp, one MMcf/day field compressor were $3,900, or 6% of the $65,000 capital cost of such a compressor, based upon an estimate of such costs furnished by the natural gas industry.(287) Inasmuch as the Government presented no credible evidence to the contrary, (288) the court accepts Mr. Platt's $4,500 figure as a reasonable approximation of the annual operating and maintenance costs for a typical 75-hp field compressor in 1975.

Following the approach taken by both Mr. Platt and FERC, in their respective compression cost studies, the $4,500 of operating and maintenance cost is added to the annual capital cost recovery charge, recomputed herein at $12,211, *supra*, in order to derive the total annual costs, excluding fuel, associated with a typical 75-hp field compressor, in the sum of $16,711. Because the RMFP is stated on a per-Mcf basis, the total annual non-fuel cost of compression must be converted to an average cost per Mcf. Two steps are required. First, the $16,711 annual non-fuel cost is divided by 365, so as to derive the average daily non-fuel cost of compression, in the sum of $45.78. Second, the average daily non-fuel cost of compression must be divided by the average daily volume of gas compressed, in Mcf, in order to derive the cost per Mcf, per stage of compression. In performing this second step, Mr. Platt used the figure of one MMcf (1,000 Mcf), on the assumption that a typical 75-hp field compressor always operates at its full one MMcf/day capacity. The court finds this assumption unrealistic, however.

This is so because it is a matter of common knowledge that no machinery operates constantly at its full capacity, 24 hours a day, 365 days a year, due to "down time" caused by periodic maintenance, supply interruptions, and other events. Therefore, Mr. Platt's full-utilization assumption unreasonably understates the actual non-fuel cost of compression per Mcf, because it spreads the average daily non-fuel cost of compression over more units of gas than the typical 75-hp field compressor can handle daily, on the average, as a practical matter. We note, further, that pursuant to its 1980 compression cost study, FERC determined that "a 95 percent load factor is representative of compression operations overall." *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44504 (Sept. 27, 1983). Consistent with the foregoing, in recomputing the average non-fuel cost of compression per Mcf, here at bar, the court applied a 95% "load factor" adjustment, under which the average daily compressed volume is presumed to be 950 Mcf, *i.e.*, 95% of the daily capacity of the typical 75-hp field compressor. Upon dividing the $45.78 average daily non-fuel cost of compression by the assumed average daily compressed volume of 950 Mcf, we derive an average non-fuel cost of compression in the sum of $0.0482 per Mcf.[(289)] Thus, on this record, the court holds that the sum of $0.04819 constitutes a reasonable approximation of the average non-fuel cost of compression per Mcf, per stage of compression, with respect to a typical 75-hp field compressor in 1975.

The third, and final, element of compression costs addressed in Mr. Platt's study is the cost of fuel. As noted above, reciprocating field compressors are typically gas-fueled, consuming a portion of the same natural gas that is being compressed. Mr. Platt determined that the fuel consumption rate for compression is approximately 10 cubic feet of gas, per horsepower-hour (cf/hp-hr).[(290)] Given a typical 75-hp, one MMcf/day field compressor, 10 cf/hp-hr of fuel usage equates to 0.0180 Mcf of fuel usage per Mcf of gas compressed, for each stage of compression.[(291)] Inasmuch as the foregoing is adequately supported by the record, and was not contested by the Government at trial, the court adopts Mr. Platt's fuel usage determination, and incorporates same into the findings of fact made herein.

With respect to each transaction in issue that involved compression before sale, Mr. Platt priced the gas consumed as compressor fuel by reference to the price at which the producer sold its gas in 1975, under the pertinent gas purchase contract. The court finds this approach to pricing field compressor fuel logical and reasonable. Because the producer uses a portion of the gas produced by its own well to fuel the compressor appurtenant to such well, the producer's economic cost of fuel equals the revenue foregone by using such gas as compressor fuel. Moreover, at trial, the Government raised no objection to Mr. Platt's compressor fuel pricing methodology. Accordingly, for purposes of determining the applicable costs of compression, the court adopts Mr. Platt's method of pricing compressor fuel.

Having made the foregoing findings as to the three elements of the cost of compression -- the capital cost of the compressor, operating and maintenance costs, and the cost of fuel -- we now turn to the application of those cost factors to the 243 transactions in the court's RMFP sample that involved compression before sale. In order to appropriately apply the three compression cost factors to a transaction in issue, one must first determine the number of stages of compression that were required for each well associated with that transaction. An example, based upon one such transaction, will best illustrate this procedure. Transaction G0658, which is included in the court's 308-transaction RMFP sample, pertains to Houston Pipe Line Company's purchase of 40,045 Mcf of gas in 1975, at a total price of $51,159, or $1.2775 per Mcf, from a single well located in Jackson County, Texas. Because the gas purchase contract provided for a pipeline maximum delivery pressure (MDP) of 750 psi, but the well produced gas at a flowing tubing pressure (FTP) of only 115 psi in 1975, Mr. Platt concluded that the producer was required to compress its gas before sale.

The next step is to determine the number of stages of compression required for the well associated with transaction G0658. As noted above, the number of required stages of compression can be determined from the per-stage compression ratio of the compressor, determined herein to be 3.5 to 1 in the case of a typical field compressor, *supra*, and the overall compression ratio, which can be inferred from the differential between the FTP of the producer's well and the MDP of the purchaser's pipeline. In computing the overall compression ratio, Mr. Platt used the following equation: overall compression ratio = MDP ÷ (FTP - 25 psi).[(292)] Thus, the overall compression ratio for transaction G0658 is 8.33 to 1 (750 psi MDP ÷ (115 psi FTP - 25 psi)). Because the overall compression ratio exceeds the compression ratio for a single stage of compression (3.5 to 1), more than one stage of compression is required. Stated differently, a single stage of compression would raise the pressure of the producer's gas to only 315 psi (3.5 x (115 psi FTP - 25 psi)), which is insufficent to overcome the MDP of 750 psi. However, on these facts, two stages of compression were sufficient to increase the pressure of the producer's gas to approximately 1,103 psi (3.5 x 3.5 x (115 psi FTP - 25 psi)), which exceeds the MDP, thereby allowing the gas to flow into the purchaser's pipeline.[(293)]

Having ascertained that two stages of compression were required in transaction G0658, the dollar cost of compression per Mcf can be determined in five simple steps. First, the average non-fuel cost of compression per stage determined herein, *supra*, in the sum of $0.0482 per Mcf, is multiplied by two (the number of required stages of compression), yielding a non-fuel compression cost of $0.0964 per Mcf. Second, we compute the fuel usage to be approximately 1,442 Mcf, the product of 40,045 Mcf (the volume of gas sold in transaction G0658), multipled by two (the number of stages), multiplied by 0.0180 (the fuel usage in Mcf per stage, for each Mcf of gas compressed, *supra*). Third, the 1,442 Mcf of fuel usage is multiplied by $1.2775/Mcf (the sale price of the gas in transaction G0658), in order to derive the total fuel cost, in the sum of approximately $1,842. Fourth, the total fuel cost of $1,842 is divided by 40,045 Mcf (the volume of gas sold in transaction G0658), so as to derive the fuel cost per Mcf, in the sum of $0.0460/Mcf. Lastly, upon adding the fuel cost of $0.0460/Mcf to the non-fuel cost of $0.0964/Mcf, *supra*, we derive the total per-Mcf cost of compression for transaction G0658, in the sum of $0.1424/Mcf. Given all of the foregoing, we hold that Mr. Platt's methodology, as adjusted by the court herein, *supra*, produces a reasonable approximation of the applicable costs of compression with respect to transaction G0658, and any other transaction in issue for which Mr. Platt had all of the data required to perform the calculations set forth above.

Mr. Platt's methodology is flawed, however, in the case of any transaction for which the FTP data for the related well(s) is incomplete or nonexistent, because the number of required stages of compression, *supra*, cannot be accurately calculated without such FTP data.[(294)] Where Mr. Platt had no FTP data for one or more wells in issue, he sought to overcome this impediment by making assumptions that we find speculative at best. Specifically, in the case of transactions with incomplete FTP data, *i.e.*, the FTP was known for some of the pertinent wells but not others, Mr. Platt calculated the compression cost for each well having FTP data, then merely *assumed* that the cost of compression for each well *lacking* FTP data equaled the volume-weighted average cost of compression for the well(s) having FTP data. Somewhat similarly, where Mr. Platt had *no* FTP data for a transaction -- either because he was unable to identify any wells associated with the transaction, or was unable to obtain any FTP data for the wells he identified

-- he simply *assumed* that the compression cost for that transaction was $0.04508/Mcf, a figure that purports to be the aggregate volume-weighted average compression cost determined with respect to all 2,058 of the transactions in Mr. Ellis' RMFP study.(295)

We find Mr. Platt's assumptions, *supra*, to be no more than an exercise in self-serving speculation. The record furnishes no reasonable assurance that such assumptions, on the whole, produce a reasonably conservative result -- one tending to err, if at all, in the direction of overstating the actual cost of compression and, thus, understate the RMFP -- as opposed to *under*stating the cost of compression and artificially inflating the RMFP. Stated differently, the court has no way of ascertaining, on this record, whether any resultant errors tend to cancel each other out, on the average, in that any understatement of the costs of compression for some transactions is offset by the overstatement of the compression costs for others. Accordingly, we reject Mr. Platt's usage of unsubstantiated weighted-average cost assumptions to estimate the compression requirements for wells lacking actual FTP data.

Given the speculative nature of Mr. Platt's approach, the court has considered whether the record suggests a more conservative assumption regarding the compression requirements for wells lacking FTP data. Having done so, we have determined that four stages of compression, at a compression ratio of 3.5 to 1 per stage, are sufficient to compress even gas produced by very low-pressure wells to pipeline delivery pressures. Utilizing Mr. Platt's overall compression ratio equation, *supra*, where the pipeline MDP is 1,000 psi, we find that four stages of compression are required if the well's FTP falls between roughly 32 psi and 48 psi.(296) Wells producing gas at pressures below this level are uncommon and generally produce gas in such small volumes as to be immaterial to the RMFP computation.(297) Accordingly, for purposes of recomputing the compression cost for any wells in issue that lack FTP data, on the basis of a more suitably conservative assumption regarding the number of required stages of compression, we hold that each such well shall be presumed to have required four stages of compression in 1975.

As adjusted herein, *supra*, Mr. Platt's methodology produces a conservative, reasonable estimate of the typical cost of compression in 1975, as evidenced by a comparison with the other estimates of compression costs in the record. In particular, we note that FERC, pursuant to its 1980 compression cost study, *supra*, which culminated in final regulations issued in September of 1983, adopted a compression cost allowance of $0.06/MMBtu per stage, exclusive of fuel costs. 18 C.F.R. chap. 1, § 271.1104(d)(1)(iv)(A) (1983). Based upon typical heating values for raw natural gas in the Texas Gulf Coast/East Texas region, the figure of $0.06/MMBtu equates to a volumetric (per-Mcf) compression cost of approximately $0.0652/Mcf.(298) Adjusted for inflation, this figure translates to roughly $0.0441/Mcf in 1975 dollars,(299) which reasonably compares with the typical non-fuel cost of compression of $0.0482/Mcf per stage determined under Mr. Platt's method, as adjusted herein.

Further, on the Government's behalf, Mr. Nicol opined that, within a 25% to 30% margin of error, the cost of compression in 1975 was typically $0.04 to $0.06 per Mcf per stage.(300) Taking his stipulated 25% to 30% margin of error into account, Mr. Nicol's estimate suggests a range of compression costs of roughly $0.03 to $0.08 per Mcf per stage. With the adjustments made herein, Mr. Platt's methodology yields a range of compression costs, including fuel, of approximately $0.0504 to $0.0860 per Mcf per stage, which compares reasonably with the range of compression costs suggested by Mr. Nicol.(301)

Given the foregoing, we conclude that the adjusted Platt methodology produces results that are reasonably consistent with the other estimates of 1975 compression costs in evidence. Thus, on this record, for purposes of applying the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78, we hold that a compression cost deduction shall be made in the sum of $0.0482 per Mcf, plus fuel costs as stated above, for each required stage of compression, with respect to each transaction in issue that involved compression of the gas before sale. In addition, as stated above, relative to any well in issue for which the record contains no flowing tubing pressure (FTP) data, we hold that the aforesaid compression cost deduction shall be made on the presumption that such well required four stages of compression in 1975. The discussion now turns to the adjustments required under the "preferable" method, *supra*, in connection with transactions in which the producer dehydrated the gas before sale.

5. *Adjustments For Costs Of Dehydration Prior To Sale*

Dehydration removes excess water *vapor* from raw natural gas, through a chemical process ably explained by the Court of Federal Claims in Exxon I, as follows:

The most common dehydration process involves passing trimethylene glycol through the gas. A typical dehydrator is a vertical cylindrical tank. Gas enters the bottom of the tank and glycol enters the top and falls to the bottom. As the gas moves upward through the glycol, the glycol absorbs the water vapor in the gas.

Exxon I, 33 Fed. Cl. at 257.[(302)] It is undisputed that virtually all of the natural gas produced in the Texas Gulf Coast/East Texas region comes out of the ground saturated with water vapor, to a degree greatly exceeding the typical pipeline company gas quality specification of seven pounds of water vapor per MMcf. See Exxon I, 33 Fed. Cl. at 257, 277 (similar finding, relative to 1974). Thus, with respect to each of the 308 transactions in the court's RMFP sample, we take it as a given that the gas required dehydration.[(303)]

The question, then, is whether the gas was dehydrated prior to sale, by the producer, or thereafter, by the purchasing pipeline company. On Exxon's behalf, Mr. Ellis made this determination by reviewing the pipeline company gas purchase contracts (PX 14a, PX 14b) relating to the 2,058 transactions in his RMFP sample. Whenever a gas purchase contract contained a maximum water vapor content specification, *i.e.*, seven pounds of water vapor per MMcf, or expressly stated that the seller was required to dehydrate the gas, Mr. Ellis concluded that the seller dehydrated the gas prior to sale. Conversely, where the contract lacked a maximum water vapor content specification, or expressly stated that the purchaser was required to dehydrate the gas, Mr. Ellis concluded that the seller did not dehydrate the gas prior to sale.[(304)] Inasmuch as Mr. Ellis' approach is reasonable and logical, and was unchallenged by the Government's experts at trial, the court adopts it herein. Thus, based upon Mr. Ellis' uncontested determinations, as confirmed in significant part by our examination of the gas purchase contracts in PX 14a and PX 14b, the court finds that 140 of the 308 transactions in our RMFP sample involved dehydration before sale.[(305)] We turn now to the costs of such dehydration.

As with the cost of compression, *supra*, in determining a reasonable approximation of the applicable costs of dehydration, the court herein follows the approach delineated in Mr. Platt's dehydration cost study, making appropriate adjustments where required. Mr. Platt's study addresses four factors that make up the cost of dehydration: (i) the capital cost of the dehydration equipment; (ii) the cost of the triethylene glycol (*i.e.*, the chemical that absorbs the water vapor) lost in the dehydration process; (iii) the costs of operating and maintaining the dehydrator; and (iv) the cost of fuel. We address each of these four cost factors below, *seriatim*.

Regarding the capital cost of the dehydration equipment, Mr. Platt assumed that a typical field dehydrator handles one MMcf of gas per day, the same daily volume he assumed in the case of compression. For the Government, Mr. Martin raised essentially the same objection that he made in relation to Mr. Platt's compression cost study -- that the assumption of a one MMcf/day dehydrator, operating at full capacity, understates the actual cost of dehydration for transactions involving less than one MMcf/day of gas production -- but also conceded that Mr. Platt's approach *over*states the actual cost of dehydration for transactions involving *more* than one MMcf/day of gas production.(306) With the foregoing in mind, the court observes that, of the total volume of gas represented in the 140 transactions in the court's RMFP sample that involved dehydration before sale (33,661,145 Mcf), over 58% of such gas (19,650,626 Mcf) was sold in transactions involving more than 365,000 Mcf in 1975 (*i.e*., one MMcf/day annualized). Thus, as in the case of compression, *supra*, we find that any understatement of the dehydration costs in connection with the sub-365,000-Mcf transactions is offset, if not outweighed, by the overstatement of the dehydration costs with respect to the transactions involving more than 365,000 Mcf. Accordingly, for purposes of determining a reasonable approximation of the applicable costs of dehydration, relative to the court's 308-transaction RMFP sample, we find that Mr. Platt's assumption of a one MMcf/day dehydrator tends, *on the average*, to produce a conservative result, *i.e*., tending to overstate the capital cost of dehydration per Mcf.

In determining the dollar cost of a one MMcf/day dehydrator, as of 1975, Mr. Platt relied upon a U.S. Department of Energy publication reporting that the cost of a typical one MMcf/day dehydrator in South Texas was $14,900 in 1995. Energy Information Administration, Office of Oil and Gas, U.S. Department of Energy, *Costs and Indices for Domestic Oil and Gas Field Equipment and Production Operations, 1992 Through 1995* (Aug. 1996) (hereinafter, "DOE Report"), at 79, reproduced at PX 5, SubX 21. Using inflation indices furnished by the DOE Report, Mr. Platt determined that a one MMcf/day field dehydrator costing $14,900 in 1995 dollars would have cost approximately $9,500 in 1975 dollars. Neither of the Government's dehydration experts, Messrs. Nicol and Martin, challenged this determination. Therefore, on this record, the court finds that $9,500 is a reasonable approximation of the cost of a typical one MMcf/day field dehydrator in 1975.

Thereafter, using the same discounted cash flow (DCF) equation employed in his compression cost study, Mr. Platt calculated the annual capital cost recovery charge for a typical one MMcf/day field dehydrator, over an assumed useful life of 15 years, at a discount rate of 8% (the average prime rate for 1975), to be $1,100. Based upon the same rationale delineated in connection with compression costs, *supra*, we recomputed the annual capital cost recovery charge on the basis of a 14% discount rate, on the ground that the cost of capital for a field dehydrator must reflect a reasonable risk premium. On the basis of our recalculation, the court finds that an appropriate annual capital cost recovery charge for a typical one MMcf/day field dehydrator purchased in 1975 is approximately $1,547.

Turning to the second element of dehydration costs, triethylene glycol (commonly referred to simply as "glycol") is a chemical used in dehydrators that has an affinity for, and absorbs, the water vapor in natural gas.(307) Glycol is constantly recirculated through the dehydrator. After the glycol becomes saturated with water vapor in the "absorber" section of the dehydrator, it is removed to the "reboiler" section of the dehydrator, where it is heated in order to release the water vapor. Thereafter, the glycol, freed of water vapor, is pumped back into the absorber and the aforesaid process is repeated. Although glycol evidently can be recycled almost indefinitely in the foregoing manner, Mr. Platt explained that "extremely small" amounts of glycol are lost in the process, in amounts approximating 0.10 gallons of glycol per MMcf of gas dehydrated. Based upon price quotations obtained from two vendors in 1997, in the sums of $0.542/pound and $0.51/pound, which equates to roughly $5.00 per gallon, Mr. Platt determined that the price of triethylene glycol, adjusted for inflation, was approximately $2.50 per gallon in 1975 dollars. Based upon that price, Mr. Platt calculated the 1975 cost of glycol losses for a typical one MMcf/day field dehydrator to be approximately $91 per year (*i.e*., 365 MMcf/year x 0.10 gal./MMcf glycol loss x $2.50/gal. = $91.25). Neither of the Government's dehydration experts, Messrs. Nicol and Martin, challenged Mr. Platt's determination. Accordingly, on this record, the court finds that Mr. Platt's uncontested estimate of $91 per year reasonably approximates the cost of glycol losses for a typical field dehydrator in 1975.

The third element of dehydration costs addressed by Mr. Platt is the annual cost of operating and maintaining a typical field dehydrator. Here, as with his compression cost study, Mr. Platt estimated that the annual operating and maintenance costs equal 6% of the capital cost of the equipment, or $570/year (*i.e*., $9,500 capital cost x 6% = $570). Although Mr. Platt cited no authority for the aforesaid estimate, apart from his own experience with the design and installation of dehydrating equipment, he opined that the 6% figure probably overstates the annual operating and maintenance costs for a typical field dehydrator because, relative to compressors, dehydrators generally require less maintenance. Inasmuch as the record shows that a glycol dehydrator is a mechanically simpler device, having many fewer moving parts than a reciprocating compressor, we find Mr. Platt's reasoning persuasive and conservative.[(308)] Further, the Government presented no probative evidence to the contrary. Thus, on this record, the court finds that the sum of $570 reasonably approximates the annual costs of operating and maintaining a typical field dehydrator in 1975.

Turning to the fourth, and final, element of dehydration costs considered in Mr. Platt's study -- the cost of fuel -- we note that field dehydrators, like field compressors, typically use the natural gas produced by the related well(s) as a fuel source. Such gas is burned to heat the reboiler section of the dehydrator. Mr. Platt estimated that a typical field dehydrator consumes 900 cubic feet (cf) of gas fuel for each MMcf of gas that is dehydrated.[(309)] Although Mr. Platt cited no authoritative source of information regarding dehydrator fuel usage, he is amply qualified to render an opinion on that subject, given his 35 years of experience as a petroleum engineer. Moreover, his testimony was credible and totally unchallenged by the Government. Therefore, on this record, the court finds that Mr. Platt's uncontested opinion, to the effect that it requires 900 cf of gas fuel to dehydrate one MMcf of gas, furnishes a reasonable approximation of the fuel requirements of a typical field dehydrator in 1975.

Having made all of the foregoing determinations, the court finds, further, that as of the year 1975, the total annual non-fuel cost of operating a typical one MMcf/day glycol field dehydrator was $2,208, representing the sum of: (i) the annual capital cost recovery charge, as adjusted herein, in the sum of $1,547; (ii) the annual cost of glycol losses, in the sum of $91; and (iii) the annual operating and maintenance costs, in the sum of $570. For purposes of converting the annual non-fuel cost to the cost per Mcf of gas dehydrated, the court made a second adjustment to Mr. Platt's methodology for estimating the costs of dehydration. Specifically, as with the cost of compression, Mr. Platt assumed that a typical glycol field dehydrator operates year round at full capacity, *i.e*., dehydrating one MMcf of gas per day. Finding that assumption implausible, the court applied a 95% load factor adjustment (consistent with the approach taken herein in connection with the cost of compression, *supra*), meaning that we presume the average daily dehydrated volume to be 950 Mcf, *i.e*., 95% of the daily capacity of the typical one MMcf/day field dehydrator. Upon taking this load factor adjustment into account, we hold that the non-fuel cost of operating a typical glycol field dehydrator, as of 1975, was $0.00637 per Mcf of gas dehydrated (*i.e*., $2,208 annual non-fuel cost, as adjusted herein, divided by 365 days per year, divided by the presumed daily dehydrated volume of 950 Mcf).[(310)]

To the non-fuel cost of compression determined above, the cost of fuel must be added. Consistent with his treatment of fuel costs in the context of the cost of compression, *supra*, Mr. Platt priced the gas consumed as dehydrator fuel in accordance with the price at which the producer sold its gas under the pertinent gas purchase contract. As noted above, relative to compression, we find this approach to be a logical and reasonable method of pricing the gas consumed as fuel. Priced in this manner, the cost of dehydration fuel ranges from approximately $0.00011 to $0.00189 per Mcf, depending upon the sale price of the gas in each transaction.[(311)] Upon adding such fuel costs to the non-fuel dehydration cost of $0.00637/Mcf determined herein, *supra*, we find that the total cost of dehydration ranges from $0.00648 to $0.00826 per Mcf.

There being no credible evidence to the contrary,(312) the court concludes that Mr. Platt's methodology, as adjusted herein, produces a reasonable approximation of the typical costs of glycol field dehydration in 1975. Consequently, for purposes of applying the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78, we hold that a dehydration cost deduction shall be made in the sum of $0.00637 per Mcf, plus fuel costs as delineated above, with respect to each transaction in issue that involved dehydration of the gas before sale. Below, we summarize our conclusions regarding the costs of compression and dehydration, calculated in connection with the 308 transactions in the court's RMFP sample.

6. *Conclusion -- Compression And Dehydration Adjustments*

As noted above, relative to the 308 transactions in the court's RMFP sample, the sale price of the gas in 278 such transactions was tainted as a consequence of the gas being compressed, or dehydrated, or both, prior to sale.(313) In redetermining the applicable costs of compression and dehydration, under Mr. Platt's methodology, as adjusted herein, *supra*, the court found it impracticable to make all of the foregoing intricate computations in connection with each and every one of the 278 tainted transactions in issue. Therefore, we recalculated Mr. Platt's compression and dehydration charges, with respect to a substantial proportion of the volume of gas (Mcf) represented in the 278 tainted transactions, then extrapolated the results to the entire 308-transaction RMFP sample. Specifically, of the 76,392,770 Mcf of gas associated with the 243 transactions tainted by compression, the court recomputed the compression charges for a subsample of transactions representing approximately 74% of such gas (56,340,408 Mcf). By extrapolating the results of our calculations to all of the 243 transactions in our RMFP sample that were tainted by compression, the court determined that the compression charges relating to the 76,392,770 Mcf of compression-tainted gas must be increased, over and above the compression charges determined by Mr. Platt, by the sum of approximately $1,216,000, or $0.0159 per Mcf. Similarly, of the 33,661,145 Mcf of gas represented in the 140 transactions tainted by dehydration, we recalculated the dehydration charges for a subsample of transactions representing approximately 55% of such gas (18,640,980 Mcf). Upon extrapolating the results of the aforesaid calculation to all of the 140 transactions in our RMFP sample that were tainted by dehydration, we determined that the compression charges for the 33,661,145 Mcf of dehydration-tainted gas must be increased by the amount of approximately $54,000, or $0.0016 per Mcf.

We summarize the effect of the above referenced redeterminations upon the RMFP computation, in connection with the court's 308-transaction RMFP sample, as follows:

Tentative adjusted sale price of gas, *i.e.*, reduced by compression $77,908,091(314)

and dehydration deductions determined by Mr. Platt

Additional compression-related deductions, determined above (1,216,000)

Additional dehydration-related deductions, determined above (54,000)

Redetermined adjusted sale price $76,638,091

Divide by total volume of gas in 308-transaction RMFP sample (Mcf) 112,194,856

Representative market or field price (RMFP) $0.6831/Mcf.(315)

J. *Determination Of The RMFP -- Conclusion*

As the preceding analysis demonstrates, this court has taken great pain to select, given the gargantuan record assembled at trial, a balanced, representative sample of 308 transactions involving the sale of raw gas "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a), that was produced within the Texas Gulf Coast/East Texas region during 1975, and that was reasonably comparable to the Exxon gas in issue. Perhaps neither litigant will be entirely satisfied with the RMFP sample the court has selected. The Government plainly would prefer, of course, a sample of transactions more heavily weighted in favor of low-priced *inter*state transactions, whereas, conversely, Exxon, no doubt, would like to have its RMFP computed on the basis of a sample of transactions that markedly favors high-priced *intra*state gas. However, as explained above, fidelity to precedent requires that the court "achieve a balance" between interstate and intrastate gas, "thereby making the price more representative." Panhandle, 408 F.2d at 708, 187 Ct. Cl. at 157. Were courts to overlook this fundamental principle, such shortsightedness would invite the sort of subjectivity observed here at bar, where each litigant has favorably loaded its proposed RMFP computation with the class of transactions, interstate or intrastate, that is most hospitable to its cause.

Further, we fully acknowledge the likelihood that Exxon might disagree with our holding, after the fact, on the ground that some other subsample of the 2,058 transactions included in its RMFP study, yet unrevealed, is purportedly more "representative" than the sample of 308 transactions that we have chosen. Stated differently, Exxon could advance self-serving arguments to the effect that our 308-transaction RMFP sample could be improved upon, through the addition or deletion of certain transactions. We are constrained to note, however, that Exxon's claimed entitlement to a percentage depletion allowance, for the taxable year 1975, hinges upon a narrow exception to the general repeal of percentage depletion on natural gas production, effective January 1, 1975 -- the fixed contract exception of § 613A(b)(1)(B) -- that was generously intended by Congress to ease the post-repeal transition in the case of natural gas producers locked into fixed-price contracts. In analogous circumstances, the Supreme Court has declared that, when the beneficiary of such transitional tax legislation claims, as here, an "extraordinary deduction," there is "certainly no need for that deduction to be microscopically fair." Atlantic Mutual Ins. Co. v. Commissioner, 523 U.S. 382, 118 S. Ct. 1413, 1418 (1998). Thus, in the case at bar, Exxon is entitled to have its 1975 RMFP computed on the basis of "a *fair* selection of contracts," nothing more. Hugoton I, 161 Ct. Cl. at 289, 315 F.2d at 877 (emphasis added). No greater degree of precision can be demanded, given that the RMFP computation is merely "an inexact, simplified means of calculating an integrated producer's depletion deduction." Exxon I, 88 F.3d at 976. Consequently, "the price so derived *is not to be disregarded merely because it is an approximation*." Hugoton I, 161 Ct. Cl. at 281, 315 F.2d at 872 (emphasis added).

In short, given our painstaking efforts to faithfully adhere to the standards that govern the determination of an RMFP for natural gas, as laid down by the controlling precedents, *i.e.*, the Hugoton, Panhandle, and Exxon I decisions, *supra*, neither party can creditably attack the RMFP we have determined herein, save by advocating the sort of "reasonableness" analysis that the Federal Circuit condemned in Exxon I, 88 F.3d at 980. However, once an RMFP has been established, as here, on the basis of a suitably objective and representative sample of transactions involving the sale of comparable raw gas in the taxpayer's market area, such an RMFP cannot be invalidated on the ground that it is unreasonable. On the contrary, such a validly-determined RMFP "is per se reasonable." Exxon I, 88 F.3d at 980.

Accordingly, on the foregoing record, the court holds that the "representative market or field price" (RMFP), within the meaning of Treas. Reg. § 1.613-3(a), was $0.6831 per Mcf, with respect to Exxon's production of gas well gas, representing 90.26% of the total volume (Mcf) of the disputed gas production from the 369 Exxon properties in issue, during the taxable year 1975. The analysis now turns, at last, to the final substantive issue remaining to be decided herein -- whether the natural gas that Exxon sold during 1975, pursuant to its contracts with Houston Lighting & Power Co. (HL&P) and Southwestern Electric Power Company (SWEPCO), constituted "natural gas sold under a fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A).

IV. *Qualification Of The HL&P And SWEPCO Contracts As "Fixed Contracts"*

A. *Statutory Background*

In 1975, as noted above, the Code defined "natural gas sold under a fixed contract," *i.e.*, gas eligible for percentage depletion under the fixed contract exception, as "domestic natural gas sold by the producer under a contract, in effect on February 1, 1975, and at all times thereafter before each sale, under which the price for such gas *cannot* be adjusted to reflect *to any extent* the increase in liabilities of the seller for tax under this chapter by reason of the repeal of percentage depletion." § 613A(b)(2)(A) (emphasis added). However, the Code furnishes no specific guidance regarding the circumstances in which a contract price adjustment, *i.e.*, a price increase, "reflects" a gas producer's increased income tax liabilities arising from the repeal of percentage depletion. Rather, Congress simply declared that "[p]rice increases after February 1, 1975, *shall be presumed* to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by *clear and convincing evidence*." § 613A(b)(2)(A) (emphasis added).

Although the Code says nothing more on the subject of the fixed contract exception,(316) further guidance is provided by Treas. Reg. § 1.613A-7, as follows:

§ 1.613A-7 Definitions.

For purposes of section 613A and the regulations thereunder --

(c) Regulated natural gas. . . .

* * * * *

(5) . . . . Price increases after February 1, 1975, are presumed to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by clear and convincing evidence that the increases are *wholly* attributable to a purpose or purposes unrelated to the repeal of percentage depletion

for [natural] gas. . . . Increases to reflect additional State and local real property or severance taxes, increases for additional operating costs (such as costs of secondary or tertiary processes), adjustments for inflation, increases for additional drilling and related costs, or increases to reflect changes in the quality of the gas sold, are some examples of increases that are not attributable to the repeal of percentage depletion for [natural] gas.

(d) Natural gas sold under a fixed contract. . . . Price increases after February 1, 1975, are presumed to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by clear and convincing evidence. Paragraph (c) of this section provides examples of increases which do not take increases in tax liabilities into account. However, if an adjustment provided for in the contract permits the possible increase in federal income tax liability of the seller to be taken into account to any extent, the gas sold under the contract after such an increase becomes permissible is not gas sold under a fixed contract. If the adjustment provided for in the contract provides for an increase in the price of the contract to the highest price paid to a producer for natural gas in the area, or if the price may be renegotiated, then gas sold under the contract after such an increase becomes permissible is presumed not to be sold under a fixed contract unless the taxpayer demonstrates by clear and convincing evidence that the price increase *in no event* takes increases in tax liabilities into account.

Treas. Reg. § 1.613A-7(c), (d) (emphasis added). Thus, Treas. Reg. § 1.613A-7 delineates various examples of price increases that are either allowable under the fixed contract exception, *i.e.*, a price increase "wholly attributable . . . [to] additional State and local real property or severance taxes," etc., or presumed to be impermissible, absent clear and convincing evidence to the contrary, *i.e.*, a price increase tied to "the highest price paid to a producer for natural gas in the area." Id. Having thus delineated the statutory and regulatory contours of the fixed contract exception, we turn now to consider the operative factual circumstances which gave rise to the instant controversy over the HL&P and SWEPCO contracts.

B. *Factual Background*

1. *The HL&P Contract*

By contract dated September 6, 1963, Exxon and HL&P agreed that Exxon would sell and deliver natural gas to HL&P, during the 20-year period beginning on January 1, 1965, and ending on January 1, 1985, for use as fuel in several electric generating plants that HL&P operated in the city of Houston, Texas, and the surrounding area.(317) With respect to pricing, the contract provided that HL&P was to pay 20.5¢ per MMBtu for Exxon's gas during the first six contract years, *i.e.*, the calendar years 1965-1970, and 21¢ per MMBtu during the succeeding four contract years, *i.e.*, 1971-1974.(318) Thereafter, relative to the pricing during the last ten contract years, *i.e.*, 1975-1984, the contract provided as follows:

At least one (1) year prior to the beginning of the eleventh (11th) contract year [*i.e.*, the calendar year 1975] and the sixteenth (16th) contract year, representatives of Seller and Buyer shall meet and attempt to determine a mutually acceptable price per million Btu to be applicable during each of the next ensuing five (5) year periods. In the event the parties are unable to agree upon such price, then Buyer shall have the right at its election, exercisable not less than six (6) months prior to the beginning of each such five (5) year period, to elect to have the price determined pursuant to either Option No. 1 or Option No. 2, hereinafter set forth; provided, however, that in the event Buyer does not make such an election then the price for the five (5) year period in question shall be determined under Option No. 1.

PX 12o at HLPF0000050-51. Thus, as originally written, the contract established no fixed price for the year 1975 (and subsequent contract years).(319)

Thereafter, by a contract amendment dated May 29, 1974, Exxon agreed to substantially increase the volume of gas it would make available to satisfy HL&P's fuel requirements, effective June 1, 1974, and to extend the contract's term in open-ended fashion, past the original expiration date of December 31, 1984, until Exxon's increased gas supply commitment was discharged.(320) Further, Exxon and HL&P established the contract price of the subject gas for each of the years 1975 through 1984. For the calendar year 1975, the price of Exxon's gas was set at 26¢ per Mcf.(321) In addition to the foregoing, the contract amendment provided that HL&P would reimburse Exxon for "excess royalty payments" attributable to the Exxon gas delivered to HL&P under the contract, as follows:

During the period beginning June 1, 1974 and ending December 31, 1987, Buyer agrees to pay its proportionate share of the royalties actually paid each month by Seller on gas entering Seller's Exxon Gas System which are in excess of the royalties which would have been paid if such royalties had been paid at the same price received by Seller from Buyer for gas delivered hereunder. The aforesaid price received by Seller from Buyer shall be equal to the sum of the amounts paid under the provisions of Sections A and B of this Article III plus any amount paid pursuant to the provisions of Article IV hereof. Buyer's proportionate share of excess royalties for which payment is due hereunder shall be computed each month based upon the ratio of the total volume of Seller's deliveries of gas to Buyer hereunder to the total volume of gas (excluding gas transported for others) entering Seller's Exxon Gas System.

PX 12o at HLPF0000012.(322) Here at bar, it is this "excess royalty reimbursement" clause that is the focal point of the parties' dispute over the qualification of the HL&P contract as a "fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A).

2. *The SWEPCO Contract*

On April 6, 1962, Exxon and SWEPCO entered into a contract, whereby Exxon agreed to sell and deliver natural gas to SWEPCO, during the 20-year period beginning on July 9, 1962, and ending on July 9, 1982, for use as fuel in three SWEPCO electric generating plants located in northeastern Texas: (i) the Lone Star Station, in Morris County; (ii) the Knox Lee Station, in Gregg County; and (iii) the Wilkes Station, in Marion County. The contract established the prices, ranging from 18.5¢ to 20.5¢ per MMBtu, that SWEPCO was to pay for Exxon's gas through December 31, 1971, and further provided, in pertinent part, as follows:

For the next five (5) year period beginning January 1, 1972, the prices shall be negotiated between the parties hereto, with the minimum and maximum prices for the first two and one-half (2-1/2) years of such period being twenty-one cents (21.0¢) and twenty-three cents (23.0¢), respectively; and the minimum and maximum prices for the last two and one-half (2-1/2) years of such period [*i.e.*, the period including the calendar year 1975] being twenty-two cents (22.0¢) and twenty-five cents (25.0¢), respectively.

* * * * *

[I]n no event shall the price or prices for any such period be less than the minimum price or more than the maximum price provided [above].

PX 12b at SWEF0000095-96. Pursuant to the foregoing, by letter agreement dated October 29, 1971, Exxon and SWEPCO fixed the contract price for the second two and one-half year period referenced above, *i.e.*, the period including the calendar year 1975, at 25¢ per MMBtu, the maximum price permissible for such period under the original contract.(323)

Subsequently, by letter agreement dated November 16, 1973, Exxon and SWEPCO agreed to cancel Exxon's gas fuel delivery obligation to SWEPCO's Lone Star Station, on or before April 1, 1974, and to thereafter reallocate that delivery obligation to SWEPCO's Knox Lee and Wilkes Stations. Specifically, before the transfer of said delivery obligation, Exxon was obliged to deliver 1,339 MMBtu/hr to the Lone Star Station, 2,300 MMBtu/hr to the Knox Lee Station, and 5,379 MMBtu/hr to the Wilkes Station, for a total delivery obligation of 9,018 MMBtu/hr. Following the transfer, Exxon's total delivery obligation of 9,018 MMBtu/hr was unchanged, but was allocable only to the Knox Lee Station (3,035 MMBtu/hr) and the Wilkes Station (5,983 MMBtu/hr).(324) In order to replace the gas fuel formerly supplied by Exxon to the Lone Star Station, SWEPCO bought gas from another supplier, Delhi Gas Pipeline Corp. Thus, the net effect of the November 26, 1973 contract amendment was to permit SWEPCO to increase the total supply of gas fuel for its Lone Star, Knox Lee, and Wilkes Stations.

With respect to the contract price, the November 26, 1973 amendment to the SWEPCO contract provided as follows, in pertinent part:

Effective January 1, 1974 and during the remaining term of said contract, the price being paid by Buyer for all gas delivered, and for the deficiency, if any, in takes of gas from Seller, shall be increased by seventy-five hundredths cent (0.75¢) per MMBtu.

Effective November 1, 1973 and thereafter during the term of the contract in addition to the price specified in said contract, including the increase herein provided for, Buyer agrees to pay to Seller an amount equal to fifteen and seven-tenths percent (15.7%) of the excess of Seller's Volume Weighted Average Field Price for gas delivered into the Exxon Gas System above such contract price in effect from time to time, such Volume Weighted Average Field Price to be determined as of the first day of each year, and to remain in effect for the purpose of determining such difference for the calendar year thereafter. For the purposes of the foregoing, the Volume Weighted Average Field Price shall be the higher of the following:

(a) The weighted average, by volumes, of Seller's Field Prices for gas taken into the Exxon Gas System in Texas Railroad Commission Districts 2, 3, 4, 5 and 6 (as now constituted) as determined from time to time by Seller, or

(b) The volume weighted average price used by Seller in computing royalty settlements for its gas entering the Exxon Gas System.

PX 12b at SWEF0000009. The controversy, here at bar, over the qualification of the SWEPCO contract as a "fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A), centers upon the second paragraph above, including subparagraphs (a) and (b) thereof.(325)

C. *Contentions Of The Parties*

Exxon contends that any price increases that took place during 1975, pursuant to the disputed pricing provisions of the HLP and SWEPCO contracts, as amended, *supra*, did not cause those two contracts to fail to meet the definition of "fixed contracts," under § 613A(b)(2)(A) and Treas. Reg. § 1.613A-7. With respect to the "excess royalty reimbursement" (ERR) clause of the HL&P contract, *supra*, under which HL&P reimbursed Exxon for HL&P's proportionate share of the "excess royalties" that Exxon was required to pay on the gas it sold to HL&P, Exxon argues that such excess royalty reimbursements are no different, in essence, than other types of cost reimbursements that are expressly permitted under Treas. Reg. § 1.613A-7, *i.e*., for additional real property taxes, severance taxes, operating costs, drilling costs, etc. Stated differently, in Exxon's view, price increases that do not permit the gas producer to offset its additional tax liabilities caused by the repeal of percentage depletion, but merely "pass through" additional producer costs to the buyer of the gas, do not cause a contract to fail to qualify as a "fixed contract." Although such cost pass-through provisions increase the gas producer's *gross* revenues, they merely offset additional costs, according to Exxon, and do not increase the producer's *net* revenue from the sale of natural gas. Thus, Exxon argues, the ERR clause in the HL&P contract, as a mere cost pass-through provision, cannot function as a vehicle for offsetting Exxon's increased income tax liabilities caused by the repeal of percentage depletion. Further, notwithstanding the fact that the disputed price adjustment clause in the SWEPCO contract, as amended, *supra*, is *not* expressly titled or described therein as an ERR clause, Exxon contends that said contract provision was, in fact, an ERR clause.

At trial, in support of its assertion that the ERR clause in the HL&P contract and the purported ERR clause in the SWEPCO contract were merely royalty cost pass-through provisions, Exxon relied upon the report and testimony of M. Glenn Whitcomb, Jr., who was employed as Manager of Gas Sales in Exxon's Natural Gas Department in Houston, Texas, from 1973 through 1986. In that capacity, Mr. Whitcomb was responsible for the administration of Exxon's contracts for the sale of gas to industrial customers, including the HL&P and SWEPCO contracts, and was personally involved in the discussions and negotiations leading up to both the May 1974 amendment to the HL&P contract and the November 1973 amendment to the SWEPCO contract. As to the circumstances that led to the negotiation of the ERR clause in the HL&P contract, Mr. Whitcomb explained that Exxon found itself in a "profit squeeze" in the 1970s, due to the brisk upward trend in gas prices in that decade, with respect to the long-term, fixed-price contracts that Exxon had entered into during the 1950s and 1960s for the sale of its gas to industrial customers, including the HL&P and SWEPCO contracts.(326)

Mr. Whitcomb attributed this "profit squeeze" to the decision in Texas Oil & Gas Corp. v. Vela, 429

S.W.2d 866 (Tex. 1968), wherein the Texas Supreme Court held that the term "market value," for purposes of royalty computations required by an oil and gas lease to be made on that basis, "clearly means the prevailing market price at the time of the sale or use" of the natural gas in question. Id. at 871. After the Vela decision, Exxon could not compute its market value-based royalty obligations on the basis of the below-market contract prices it received under long-term, fixed-price contracts written in the 1950s and 1960s. Rather, under Vela, Exxon was required, by law, to base such royalties upon the higher, prevailing market price at the time that Exxon delivered the pertinent gas to its customers, regardless of the resultant financial burden to Exxon.(327) Vela, 429 S.W.2d at 871.

At trial, Mr. Whitcomb illustrated Exxon's post-Vela "profit squeeze" with a simple hypothetical (PX 44), involving a long-term, fixed-price contract under which Exxon agreed to sell gas to a customer at the then-current market price of $0.24 per Mcf. Assuming that Exxon was obliged to pay royalties on such gas production, at a rate of one-sixth of market value, Exxon's royalty expense would initially be $0.04/Mcf (1/6 x 24¢). Thus, at the contract's inception, Exxon's net revenue would be $0.20/Mcf ($0.24 gross revenue less $0.04 royalty expense). Assume, further, that with the passage of time, the market price of natural gas rose to $0.60/Mcf. Under Vela, Exxon's royalty expense would increase to $0.10/Mcf (1/6 x 60¢), yet Exxon's gross revenue from the fixed-price contract would be unchanged, at $0.24/Mcf. Thus, a "profit squeeze" would result, in that Exxon's net revenue would fall from $0.20/Mcf, at the contract's inception, to $0.14/Mcf ($0.24 gross revenue less $0.10 royalty expense).

It was circumstances such as the foregoing, Mr. Whitcomb testified, that drove Exxon to seek price concessions in the early to mid-1970s, in the form of excess royalty reimbursement (ERR) clauses, from its customers under long-term, fixed-price contracts, *i.e.*, HL&P and, allegedly, SWEPCO. Returning to Mr. Whitcomb's illustrative hypothetical, *supra*, the negotiation and implementation of an ERR clause would have the effect of raising the contract price by the sum of $0.06/Mcf, to $0.30/Mcf. Inasmuch as it was tied to the market price, not the contract price, Exxon's royalty expense would be unchanged, at $0.10/Mcf. Therefore, Mr. Whitcomb's hypothetical ERR clause would restore Exxon to the same economic position it had originally bargained for, *i.e.*, net revenue of $0.20/Mcf ($0.30 gross revenue less $0.10 royalty expense). In short, the intended purpose of an ERR clause, according to Mr. Whitcomb, was that Exxon and its customer would compare the *actual* amount of royalties that Exxon paid, relative to the gas in question, with the *lesser* amount of royalties that Exxon would have paid, had such royalties been computed on the contract price, with the customer reimbursing Exxon for the excess. Based upon his personal involvement in the negotiations of the ERR clause in the HL&P contract, and the purported ERR clause in the SWEPCO contract, Mr. Whitcomb testified that those provisions were not intended to compensate Exxon for anything other than the excess royalty costs it was incurring on the gas it sold to HL&P and SWEPCO. Further, Mr. Whitcomb opined that neither the ERR clause in the HL&P contract, nor the alleged ERR clause in the SWEPCO contract, permitted Exxon to adjust its gas prices upward in order to recoup its increased income tax liabilities arising from the repeal of percentage depletion.

In response to all of the foregoing, the Government makes two basic arguments. First, the Government argues that excess royalty costs are not analogous to the types of pass-through costs, *i.e.*, "additional State and local real property or severance taxes, increases for additional operating costs (such as costs of secondary or tertiary processes), . . . [or] increases for additional drilling and related costs," that are listed in Treas. Reg. § 1.613A-7(c)(5). Consequently, in the Government's view, there is no legal authority for Exxon's assertion that an ERR clause constitutes a permissible price increase under § 613A(b)(2)(A).

Second, the Government maintains that § 613A(b)(2)(A) renders the parties' subjective intent in amending the contract irrelevant. Thus, with respect to the SWEPCO contract, the Government contends that Mr. Whitcomb's testimony concerning the intended purpose of the purported ERR clause in the SWEPCO contract fails to demonstrate that such clause was, in fact, related to Exxon's alleged excess royalty expenditures, as opposed to being a price adjustment tied to the repeal of percentage depletion.

[328] What is important, in the Government's view, is the *objective* effect of the disputed price adjustment clauses in the HL&P and SWEPCO contracts, *i.e*., whether the resultant price increases did, in fact, compensate Exxon for its increased income tax liabilities arising from the repeal of percentage depletion. Moreover, the Government argues, Exxon has not met its burden of proving, by clear and convincing evidence, that any and all price increases during 1975, made pursuant to the disputed price adjustment clauses in the HL&P and SWEPCO contracts, did *not* permit Exxon to recover, "to *any* extent," such increased income tax liabilities. § 613A(b)(2)(A) (emphasis added).

D. *Discussion*

Here at bar, the court is undoubtedly confronted with an issue of first impression, relative to the statutory definition of a "fixed contract" under § 613A(b)(2)(A), and the qualification of the HL&P and SWEPCO contracts thereunder, inasmuch as neither party has cited, and we have not found, any pertinent case law on point. We address this issue, it should be observed, as a mixed issue of law and fact. At the outset, the court must, of course, examine the disputed price adjustment clauses in the HL&P and SWEPCO contracts, in order to determine whether those clauses provide any mechanism whereby Exxon could legally raise the price of its natural gas in order to recoup, in whole or in part, its increased income tax liabilities arising from the repeal of percentage depletion, at any time after February 1, 1975, the cut-off date for the fixed contract exception under § 613A(b)(2)(A). That determination is a matter of contract interpretation and, thus, presents a question of law. H.B. Mac, Inc. v. United States, 153 F.3d 1338, 1345 (Fed. Cir. 1998); P.J. Maffei Bldg. Wrecking Corp. v. United States, 732 F.2d 913, 916 (Fed. Cir.1984).

Further, given that Exxon's asserted entitlement to percentage depletion deductions on the gas it sold in 1975, under the HL&P and SWEPCO contracts, hinges upon our interpretation of those contracts, in light of the statutory definition of a "fixed contract" under § 613A(b)(2)(A), the court must be ever mindful of the Supreme Court's oft-repeated directive that income tax deductions are a matter of legislative grace and are to be narrowly construed. INDOPCO, 503 U.S. at 84; Sullivan, 356 U.S. at 28; New Colonial Ice, 292 U.S. at 440. For two reasons, that venerable maxim applies with particular force to the issue presented here at bar. First, as previously noted, "unlike cost depletion, percentage depletion yields a stream of annual deductions which, over the productive life of the natural gas property, may exceed the taxpayer's investment in the property." Exxon, 40 Fed. Cl. at 76.[329] Because percentage depletion, in contradistinction to virtually every other income tax deduction enumerated in the Code, entitles the taxpayer to "an income tax deduction *without a corresponding economic outlay*, it is universally acknowledged that Congress intended the allowance for percentage depletion to serve as an economic incentive" for increased gas production and, thus, "a subsidy to natural gas producers." Exxon, 40 Fed. Cl. at 77 (emphasis added) (citing, *inter alia*, Cannelton, 364 U.S. at 81; Engle, 464 U.S. at 208-09).[330] Consequently, since its inception in 1926, percentage depletion "has been consistently regarded as a matter of legislative grace." Paragon Jewel, 380 U.S. at 631. See also Swank, 451 U.S. at 577, 579 n.11; Parsons v. Smith, 359 U.S. at 219; Southwest Exploration, 350 U.S. at 312; Anderson, 310 U.S. at 408, Bankline Oil, 303 U.S. at 366.

The second reason that the fixed contract exception to the repeal of percentage depletion must be narrowly construed, for purposes of determining whether the HL&P and SWEPCO contracts qualify thereunder, is found in the text of § 613A itself, which provides that a contract cannot qualify as a "fixed contract" unless the price of the gas "cannot be adjusted to reflect *to any extent* the increase in liabilities of the seller for tax under this chapter by reason of the repeal of percentage depletion." § 613A(b)(2)(A) (emphasis added). What is instructive about the foregoing statutory language is the fact that Congress did *not* choose merely to prohibit price increases that reflect the gas producer's increased tax liabilities to a "significant" extent, an "unreasonable" extent, a "material" extent, or any other extent of debatable meaning. On the contrary, Congress unquestionably prohibited price increases that reflect, "to *any* extent," the producer's increased tax liabilities arising from the repeal of percentage depletion. Such unequivocal statutory language undeniably denotes a clear and deliberate intention on the part of Congress that the fixed contract exception be narrowly construed. In addition, leaving no room for doubt in this regard, Congress declared that "[p]rice increases after February 1, 1975, *shall be presumed* to take increases in tax liabilities into account unless the taxpayer demonstrates to the contrary by *clear and convincing evidence*." § 613A(b)(2)(A) (emphasis added).

Given the foregoing, if a plain reading of the disputed price adjustment clause, in either the HL&P contract or the SWEPCO contract, raises *any* doubt whatsoever as to whether that clause permitted Exxon to raise the price of its gas after February 1, 1975, such that Exxon could potentially recover, in whole or in part, its increased income tax liabilities arising from the repeal of percentage depletion, the court must carefully address the factual merits of Exxon's claim. Specifically, the court must first determine whether Exxon did, in fact, increase the price of its gas, under either contract, after February 1, 1975. If so, we first must presume that any such price increase did, in fact, impermissibly compensate Exxon for its increased tax liabilities arising from the repeal of percentage depletion. Thereafter, the court must consider whether Exxon has demonstrated, by clear and convincing evidence, that said price increase did not take into account Exxon's increased income tax liabilities "to *any* extent." § 613A(b)(2)(A) (emphasis added); see also Treas. Reg. § 1.613A-7(d). We shall first address the HL&P contract, and thereafter turn to the SWEPCO contract, in order to determine whether such contracts are, in fact, "fixed" in accordance with the Code and regulations, *supra*.

1. *The HL&P Contract*

Upon examining the disputed excess royalty reimbursement (ERR) clause in the HL&P contract, as amended on May 29, 1974, the court is firmly convinced that said ERR clause permitted Exxon to raise the price of its gas after February 1, 1975, such that Exxon could potentially have recovered a portion of its increased income tax liabilities arising from the repeal of percentage depletion. We reach this conclusion because Exxon calculated the royalties payable on its gas production that entered the Exxon Gas System (*i.e.*, the Exxon pipeline system in issue), including the portion of such royalties that was eligible for reimbursement by HL&P, on the basis of the Exxon Field Price during 1975.[(331)] See Exxon I, 33 Fed. Cl. at 263 (similar finding as to usage of Exxon Field Price for royalty computations in 1974). An Exxon memorandum, received in evidence, summarizes the purpose of the Exxon Field Price, as follows:

Exxon's Field Price for natural gas is used to value gas produced from Exxon leases or gas plants when it is used by Exxon in its own field operations or when it is delivered to the Exxon Gas System for disposition off lease [*i.e.*, for transportation and delivery to industrial customers such as HL&P]. The Field Pricing system originated with Humble Oil & Refining Company before 1944, and its purpose has been to provide a basis for determining royalty and [severance] tax payments in the absence of an arm's-length field sale.

PX 1, SubX 19, at 1.

During 1975, Exxon calculated its Field Price on a two-tiered basis. With respect to gas produced from wells that were connected to the Exxon Gas System prior to the year 1972 (so-called "old vintage gas"), Exxon established its Field Price quarterly, with respect to certain specified pricing areas corresponding to one or more Texas Railroad Commission Districts, by calculating the volume-weighted average price paid by third-party natural gas pipeline companies for both raw and processed gas, as obtained from the Purchasers' Monthly Gas Tax Reports (Form 60-1.50) filed by such pipeline purchasers with the State of Texas. Although the pricing data from the aforementioned Purchasers' Monthly Gas Tax Reports was not available to Exxon until three to four months after the reporting month, such that the Field Price would, if left unadjusted, tend to lag behind the most current actual weighted average price, Exxon's management would adjust the Field Price upward in order to reflect the anticipated industry price trend. See Exxon I, 33 Fed. Cl. at 263 (similar findings as to 1974).

With respect to gas produced from wells that were connected to the Exxon Gas System after the year 1971 (so-called "new vintage gas"), Exxon established its Field Price on the first day of each calendar year, *i.e.*, as of January 1, 1975, by computing the average price paid in the preceding month of September, for the three highest-priced gas sales exceeding one thousand cubic feet per day (Mcf/day), within the Railroad Commission district in which the pertinent Exxon gas field was located, as obtained from the Purchasers' Monthly Gas Tax Reports filed by a group of 50 to 60 major gas purchasers regularly reviewed by Exxon. However, the Field Price for such "new vintage gas" could not be lower than the average of the 10 highest-priced sales exceeding one Mcf/day in Railroad Commission Districts 1 through 6, inclusive. Thus, whereas the Field Price for "old vintage gas" produced from pre-1972 Exxon wells was an *average* market price, reflective of both new, currently-priced contracts and old, lower-priced contracts, the Field Price for "new vintage gas" produced from post-1971 Exxon wells was reflective of the most *current* market prices for newly-discovered gas.

Given the foregoing, the court concludes that the Exxon Field Price was tied, at least in substantial part, to the current market price of natural gas and, therefore, reflected the upward trend in gas prices throughout the year 1975. See Exxon I, 33 Fed. Cl. at 263 & n.16 (noting similar upward trend in Exxon Field Price during 1974). Therefore, with respect to gas entering the Exxon Gas System for transportation and delivery to HL&P in 1975, the royalty expenses that Exxon incurred on such gas necessarily had to increase as well, in proportion to the upward trend of the Field Price on which such royalties were based. At trial, Mr. Whitcomb admitted that this was so.[332] Consequently, the excess royalty reimbursements that HL&P paid to Exxon during 1975 were also tied, at least in substantial part, to the current market price of natural gas.

Treas. Reg. § 1.613A-7(d) expressly refers to "an increase in the price of the contract to the highest price paid to a producer for natural gas in the area" as a price increase that is prohibited under the fixed contract exception of §§ 613A(b)(1)(B) and 613A(b)(2)(A). This prohibition extends, we think, by necessary implication, to an increase in the contract price that is *partially* premised upon the highest price paid to a producer for natural gas in the area. As explained above, due to the traditional narrow construction given to income tax deductions, INDOPCO, 503 U.S. at 84, and the deliberately narrow scope that Congress gave the fixed- contract exception to the repeal of percentage depletion, § 613A(b)(2)(A), we are constrained to presume that any doubtful price adjustment provision in the HL&P contract takes the repeal of percentage depletion into account, unless Exxon presents clear and convincing evidence to the contrary. Id. Accordingly, inasmuch as the excess royalty reimbursement (ERR) clause in the HL&P contract, as amended on May 29, 1974, permitted Exxon to raise the price of its gas after February 1, 1975, in amounts that were tied to the current market price of natural gas, we hold that Exxon, under the aforesaid pricing mechanism, could potentially have recovered a portion of its increased income tax liabilities arising from the repeal of percentage depletion.

We acknowledge, of course, that facially, the ERR clause in the HL&P contract arguably *appears* to establish a cost pass-through arrangement, under which Exxon would merely be reimbursed for its excess royalty costs incurred in connection with the gas it sold to HL&P in 1975, but not for any increased income tax liabilities arising from the repeal of percentage depletion. Further, the court acknowledges that, *if* the amounts that Exxon received pursuant to the ERR clause in the HL&P contract were, in fact, *wholly* attributable to Exxon's excess royalty costs, rather than to Exxon's increased tax liabilities, then said ERR clause did not violate the prohibition set out in § 613A(b)(2)(A). In other words, if, and only if, every dollar that Exxon received from HL&P, pursuant to the ERR clause in their contract, was demonstrably absorbed by a dollar of royalty expense that Exxon incurred with respect to the gas it sold to HL&P, then no dollars would be left over, of course, to offset Exxon's increased tax liabilities. Needless to say, however, Exxon must affirmatively *prove* that this was so, by clear and convincing evidence. § 613A(b)(2)(A).

Conversely, the court disagrees with the Government's contention that excess royalty costs are legally distinguishable from the types of pass-through costs that are specified in Treas. Reg. § 1.613A-7(c)(5), *i.e.*, "additional State and local real property or severance taxes, increases for additional operating costs (such as costs of secondary or tertiary processes), . . . [or] increases for additional drilling and related costs." Treas. Reg. § 1.613A-7(c)(5) does not purport to enumerate, in all-inclusive fashion, *every* type of permissible pass-through cost. On the contrary, said Treasury Regulation expressly states that the permissible pass-through costs listed therein are merely a few "examples" of such costs. Treas. Reg. § 1.613A-7(c)(5), (d). Moreover, like real property taxes, severance taxes, operating costs, and drilling-related costs, royalties are also direct costs of natural gas production, as opposed to indirect costs, such as corporate overhead expenses, that bear only an attenuated relationship to natural gas production. This is so because royalties are computed as a percentage of the sale price, or market value, of the gas and, thus, vary in direct proportion to the volume of gas produced from the pertinent oil and gas lease. The Code itself expressly acknowledges this direct relationship between the production of natural gas and the gas producer's royalty costs, providing that percentage depletion must be calculated upon "the gross income from the property excluding from such gross income an amount equal to any . . . royalties paid or incurred by the taxpayer with respect to the property." § 613(a). Thus, we reject, as meritless, the Government's contention that a contract calling for the reimbursement, by the purchaser of the gas, of the producer's excess royalty costs, can never qualify as a "fixed contract" within the meaning of § 613A(b)(2)(A) and Treas. Reg. § 1.613A-7(d).[(333)]

In addition to the foregoing, we note that the ERR clause is not the only price adjustment provision in the HL&P contract that, as of 1975, could potentially have allowed Exxon to recover a portion of its increased income tax liabilities arising from the repeal of percentage depletion. Specifically, Article III.D of the May 29, 1974 amendment to the HL&P contract provides:

D. Additional Gas: -- During the period beginning June 1, 1974 and ending December 31, 1984 [*i.e.*, including the year 1975] Seller, at its option, may from time to time tender gas in excess of the quantities Seller is obligated to make available to Buyer in accordance with the provisions of Article I hereof [*i.e.*, pertaining to the minimum quantity of gas deliverable to HL&P under the contract]. Excess gas so tendered by Seller shall hereinafter be identified as "Additional Gas". In the event Buyer desires to accept Additional Gas from Seller, Buyer and Seller shall negotiate in good faith to agree on *the going price for gas* in the area where the gas is to be consumed. The price to be paid for such Additional Gas shall be said going price for gas. In addition, for each three thousand cubic feet of Additional Gas sold under the provisions of this Section D, one thousand cubic feet of gas scheduled to be sold concurrently in accordance with Section A of this Article III [*i.e.*, at 26 cents per MMBtu in 1975, *supra*] *shall instead be priced at the same price as the Additional Gas* [*i.e.*, at the "going price for gas," *supra*].

PX 12o at HLPF0000013 (emphasis added).

Against this background, all that Exxon had to do, evidently, under this "Additional Gas" clause, in order to raise the price of one Mcf of its gas, otherwise committed to HL&P at the regular 1975 contract price of $0.26/MMBtu (*i.e*., the price before the purported excess royalty reimbursement, *supra*), to the "going price for gas in the area," was to make available, sell, and deliver three Mcf of "additional gas" to HL&P. The "going price for gas in the area" plainly constitutes, we think, a measure of value closely tied to the current market price of natural gas. Further, we have no doubt that Exxon, in negotiating the "going price for gas in the area" with HL&P, would seek to obtain the highest price being paid in the relevant market area. As a consequence, the Additional Gas clause clearly established a mechanism by which Exxon could achieve a prohibited "increase in the price of the contract to the highest price paid to a producer for natural gas in the area." Treas. Reg. § 1.613A-7(d). Therefore, we also hold that Exxon, under said Additional Gas clause, could potentially have recovered a portion of its increased income tax liabilities arising from the repeal of percentage depletion.

Having now determined that the HL&P contract, fairly construed, contained two provisions whereby Exxon could increase the price of the gas it sold to HL&P during 1975, *i.e*., the ERR clause and the Additional Gas clause, *supra*, we turn now to the factual issue of whether the sale price of such gas increased after February 1, 1975, the cut-off date for the fixed contract exception under § 613A(b)(2)(A). The record clearly shows that Exxon did, in fact, increase the price of its gas *after* February 1, 1975, pursuant to the ERR clause of the HL&P contract, as evidenced by the monthly ERR invoices submitted by Exxon to HL&P during 1975, and the underlying ERR workpapers that support the computation of such ERR billings, extracted from Exxon's 1975 accounting records.[(334)] Specifically, the workpaper supporting the January 1975 ERR billing purports to compute the royalties payable on gas entering the Exxon Gas System, for delivery to HL&P in January of 1975, on the basis of a weighted average Exxon Field Price of approximately $0.5192 per Mcf, or $0.5096 per MMBtu.[(335)] In February of 1975, said weighted average Exxon Field Price increased to approximately $0.5329 per Mcf, or $0.5235 per MMBtu.[(336)] By October of 1975, the last month of such year for which the record contains the pertinent Exxon ERR workpaper, the weighted average Field Price utilized in Exxon's ERR calculations had increased to roughly $0.8424 per Mcf, or $0.8250 per MMBtu.[(337)] In dollar terms, the monthly ERR charges billed by Exxon to HL&P almost tripled between January and October of 1975, from $623,022 to $1,768,818.[(338)]

As a consequence of the escalation of the aforementioned ERR charges, the total price of the gas that Exxon sold to HL&P during 1975, inclusive of ERR charges, increased from approximately $0.3035 per Mcf, or $0.2978 per MMBtu, in January of 1975, to $0.3056 per Mcf, or $0.3002 per MMBtu, in February of 1975, and to $0.3487 per Mcf, or $0.3416 per MMBtu, in November of 1975.[(339)] Here at bar, inasmuch as the sale price of Exxon's gas increased after February 1, 1975, and continued to increase on a regular monthly basis, pursuant to the ERR clause of the HL&P contract,[(340)] the court must presume that the HL&P contract failed to qualify as a "fixed contract," unless Exxon demonstrates on this record, by clear and convincing evidence, that each such price increase did *not* allow it to recover, "to *any* extent," its increased income tax liabilities arising from the repeal of percentage depletion. § 613A(b)(2)(A) (emphasis added). What this burden requires is a pointed showing, by Exxon, that every dollar that Exxon received from HL&P during 1975, under the ERR clause of their contract, was absorbed by a dollar of royalty expense that Exxon incurred with respect to the gas it sold to HL&P, such that no dollars were left over to offset Exxon's increased tax liabilities. On this record, Exxon has failed to make said obligatory showing.

With respect to each of over two dozen fields in which Exxon had gas properties, and each of the eight Exxon gas processing plants in issue, the Exxon ERR workpapers in evidence purport to tabulate the dollar amount of royalties payable by Exxon, and the related volume of gas (Mcf) that entered the Exxon Gas System for transportation and delivery to industrial customers (*i.e*., HL&P, SWEPCO, etc.) during

1975. Yet, Mr. Whitcomb had no recollection of having seen any of Exxon's 1975 ERR workpapers until the evening of February 3, 1998, approximately halfway through the trial of this case, and was unable to identify the source of any of the numerical data presented in such workpapers.(341) Moreover, Mr. Watson's report, submitted on Exxon's behalf, purports to calculate the amount of royalty expense attributable to each of the 369 Exxon properties in issue, for purposes of determining the "gross income from the property" (GIFP), net of allocable royalty expense, with respect to gas that Exxon allegedly sold under "fixed contracts" in 1975.(342) See § 613(a) (requiring the GIFP to be reduced by the allocable royalties). However, Exxon has not even attempted to demonstrate, and the court has not discovered, how the alleged royalty expenses set forth in Exxon's 1975 ERR workpapers can be reconciled, if at all, to Mr. Watson's royalty expense calculations. In addition, despite Mr. Watson's considerable knowledge of Exxon's natural gas accounting procedures and systems, as of 1975, he gave no probative testimony regarding the source of the numerical data in Exxon's 1975 ERR workpapers.(343)

Given that the origin of the numerical data tabulated in Exxon's 1975 ERR workpapers is unknown, the court cannot determine whether the putative royalty expenditures delineated therein are accurate, overstated, or understated. Without such knowledge, it would be speculative to conclude that *every* dollar that Exxon received from HL&P during 1975, under the ERR clause of their contract, was offset by an *actual* dollar of royalty expense that Exxon incurred with respect to the gas it sold to HL&P, such that Exxon was unable to recover, "to *any* extent," its increased income tax liabilities arising from the repeal of percentage depletion. § 613A(b)(2)(A) (emphasis added). Exxon's undeniable burden, however, is to make such a showing by clear and convincing evidence. Id. The Supreme Court has defined "clear and convincing" evidence as that which gives the finder of fact "an abiding conviction that the truth of [the proponent's] factual contentions are 'highly probable,'" meaning that such evidence "instantly tilt[s] the evidentiary scales in the affirmative when weighed against the evidence . . . offered in opposition." Colorado v. New Mexico, 467 U.S. 310, 316 (1984). See also Price v. Symsek, 988 F.2d 1187, 1191 (Fed. Cir. 1993). We take it as firmly settled that the foregoing standard of proof leaves no room for mere conjecture. Further, here at bar, we find it especially significant that Exxon neither called, nor demonstrated the unavailability of, any witnesses who had been employed by HL&P in 1975, and having personal knowledge of the ERR arrangement then in effect, for the purpose of establishing whether the sums billed by Exxon to HL&P during 1975, under the ERR clause of their contract, were properly calculated and truly reflective of the *actual* royalties incurred by Exxon with respect to the gas it sold to HL&P. Instead, Exxon chose to rely exclusively upon the hospitable opinion testimony of its own former employee, Mr. Whitcomb, to this effect.(344) Such proof does not, and cannot, rise to the level of clear and convincing evidence.

Pointing out that the repeal of percentage depletion was still months away, when the HL&P contract was amended to include the ERR clause, on May 29, 1974, Exxon argues that it and HL&P "did not intend" that the ERR clause would compensate Exxon for anything other than excess royalty costs. We find this contention unavailing. As the Government correctly observes, the subjective intentions of Exxon and HL&P, upon amending their contract in May of 1974, are absolutely irrelevant under the statutory definition of a "fixed contract." Nothing in § 613A(b)(2)(A) even remotely suggests that the fixed contract exception to the repeal of percentage depletion hinges upon the subjective intentions of private contracting parties. On the contrary, as noted above, Congress directed that the qualification of a contract as a "fixed contract" turns upon an *objective* inquiry, *i.e*., whether the taxpayer increased the price of its gas after February 1, 1975, and, if so, whether the taxpayer has shown, by clear and convincing evidence, that such price increase did not compensate the taxpayer, "to any extent," for its increased income tax liabilities arising from the repeal of percentage depletion. § 613A(b)(2)(A) (emphasis added).

Moreover, the court assigns no probative weight to Mr. Whitcomb's contention that Exxon was never fully reimbursed for all of the excess royalty costs that it incurred with respect to the gas it sold to HL&P

during 1975, as a result of the Texas Supreme Court's later decision in Exxon Corp. v. Middleton, 613 S.W.2d 240 (Tex. 1981). In Middleton, relative to the sufficiency of oil and gas royalties that Exxon had paid during the years 1973, 1974, and 1975, the Texas Supreme Court rejected Exxon's contention that, for purposes of calculating royalties payable on the basis of the "market value" of natural gas, the Exxon Field Price was the appropriate measure of such market value. Id. at 241, 246, 248. According to Mr. Whitcomb, under Middleton, decided in 1981, Exxon was required to retroactively pay increased royalties with respect to its natural gas production for the year 1975 (and other years not in issue here). Consequently, asserted Mr. Whitcomb, the ERR payments that HL&P made to Exxon in 1975 fell short of the actual excess royalty costs that Exxon ultimately incurred for that year, taking into account the retroactive royalty payments required under Middleton, leaving no funds to offset Exxon's increased income tax liabilities arising from the repeal of percentage depletion.

For two reasons, the court is unpersuaded by Mr. Whitcomb's assertions regarding the retroactive royalty payments that Exxon was allegedly required to make, under the Middleton decision, with respect to the year 1975. First, Mr. Whitcomb's testimony is unsubstantiated by the record, inasmuch as Exxon presented no evidence respecting the occurrence and amount of the retroactive royalty payments it allegedly made for the 1975 year. Second, as a matter of law, any retroactive royalty obligations incurred by Exxon, in any year(s) subsequent to 1975, have no bearing on the question of whether the HL&P contract qualified as a "fixed contract," within the meaning of § 613A(b)(2)(A), during the taxable year 1975. Confronted with a somewhat analogous situation in the Hugoton II case, the Court of Claims held that the calculation of the RMFP for a given taxable year is unaffected by retroactive adjustments to the sale price of the gas, arising from litigation in later years, on the ground that "[t]he income tax laws are administered on the basis of annual accounting periods and the tax is assessed on the basis of events happening in each such period." Hugoton II, 172 Ct. Cl. at 466, 349 F.2d at 432 (citing Burnet v. Sanford & Brooks Co., 282 U.S. 359 (1931)).[(345)] The Supreme Court has explained how the finality of the taxpayer's annual accounting period is essential to the effective administration of the income tax laws, as follows:

Congress has enacted an annual accounting system . . . . It would be disruptive of an orderly collection of the revenue to rule that the accounting must be done over again to reflect events occurring after the year for which the accounting is made, and would violate the spirit of the annual accounting system. This basic principle cannot be changed simply because it is of advantage to a taxpayer or to the Government in a particular case that a different rule be followed.

Healy v. Commissioner, 345 U.S. 278, 284-85 (1953), quoted with approval in Hugoton II, 172 Ct. Cl. at 466-67, 349 F.2d at 432. Like our predecessor court, we "find no compelling reason on the facts of this case to vary from this long accepted tax rule." Hugoton II, 172 Ct. Cl. at 467, 349 F.2d at 432. Thus, as a matter of law, for purposes of determining whether every dollar that Exxon received from HL&P during 1975, under the ERR clause of their contract, was offset by an *actual* dollar of royalty expense that Exxon incurred with respect to the gas it sold to HL&P, we are constrained to disregard any retroactive royalty costs, relative to the year 1975, that Exxon allegedly incurred as a result of the Texas Supreme Court's Middleton decision in 1981.

Given all of the foregoing, the court holds that Exxon has failed to prove, by the requisite clear and convincing evidence, that the multiple price increases under the HL&P contract, *supra*, that took place after February 1, 1975, the cut-off date for the "fixed contract" exception under § 613A(b)(2)(A), did not permit Exxon to recover, "to *any* extent," its increased income tax liabilities arising from the repeal of percentage depletion. § 613A(b)(2)(A) (emphasis added). Accordingly, we hold, further, that none of the gas that Exxon sold under the HL&P contract was eligible for percentage depletion, because said contract failed to qualify as a "fixed contract" under §§ 613A(b)(1)(B) and 613A(b)(2)(A). The discussion turns now to the disputed price adjustment clause under the SWEPCO contract.

2. *The SWEPCO Contract*

Unlike the excess royalty reimbursement clause in the HL&P contract, *supra*, the disputed price adjustment clause in the SWEPCO contract, as amended on November 26, 1973, states no purpose for the price increases authorized thereunder. Instead, as discussed above, the contract merely states that SWEPCO was to pay Exxon 15.7% of the excess, over the regular contract price, of Exxon's "Volume Weighted Average *Field Price* for gas delivered into the Exxon Gas System." PX 12b at SWEF0000008 (emphasis added). We have already held, in conjunction with the HL&P contract, *supra*, that any price increase tied to the Exxon Field Price was also tied, at least in substantial part, to the current market price of natural gas in the relevant market area. For that reason, as explained above, we have also held that a price increase based upon the Exxon Field Price violates Treas. Reg. § 1.613A-7(d), which expressly refers to "an increase in the price of the contract to the highest price paid to a producer for natural gas in the area," as a price increase that is prohibited under the fixed contract exception of §§ 613A(b)(1)(B) and 613A(b)(2)(A). All of the foregoing analysis applies with equal force to the disputed price adjustment clause in the SWEPCO contract. Thus, as with the ERR clause in the HL&P contract, *supra*, we hold that the disputed price adjustment clause in the SWEPCO contract, fairly construed, authorized price increases through which Exxon could potentially have recovered a portion of its increased income tax liabilities arising from the repeal of percentage depletion. Consequently, any price increases under the SWEPCO contract after February 1, 1975, the cut-off date for the fixed contract exception under § 613A(b)(2)(A), must be presumed to take the repeal of percentage depletion into account, unless Exxon presents clear and convincing evidence to the contrary. § 613A(b)(2)(A).

For two reasons, our holding above is unaltered by Mr. Whitcomb's hospitable assertion that Exxon and SWEPCO intended the disputed price adjustment clause in the SWEPCO contract to operate as an excess royalty reimbursement (ERR) arrangement, similar to that delineated in the HL&P contract, *supra*. First, as noted above, such an ERR arrangement would be inherently suspect in any event, given that Exxon's royalty costs were tied to the Exxon Field Price in 1975 and, thus, took increases in the current market price of natural gas into account. Second, nothing in the disputed price adjustment clause in the SWEPCO contract suggests that said provision established *any* type of cost pass-through mechanism, let alone an ERR arrangement.[(346)] For purposes of determining the eligibility of the gas sold thereunder for percentage depletion, the character of the SWEPCO contract, as a "fixed contract" or otherwise, must flow from the contract itself, not from Exxon's later allegations of what the contracting parties intended. See Lane Bryant, Inc. v. United States, 35 F.3d 1570, 1574-76 (Fed. Cir. 1994) (following Commissioner v. Danielson, 378 F.2d 771 (3d Cir. (*en banc*)), cert. denied, 389 U.S. 858 (1967)). Stated differently, were this court to accept Mr. Whitcomb's *post hoc* assertion that the disputed price adjustment clause in the SWEPCO contract was actually an ERR clause, that would violate "the established tax principle that a transaction is to be given its tax effect in accord with what actually occurred and not in accord with what might have occurred." Commissioner v. National Alfalfa Dehydrating & Milling Co., 417 U.S. at 134, 148 (1974).

Notwithstanding the indeterminate character of the disputed price adjustment clause in the SWEPCO contract, however, we conclude that said contract qualified as a "fixed contract" during the taxable year 1975, on the ground that the contract price did *not* increase after February 1, 1975, the cut-off date for the fixed contract exception to the repeal of percentage depletion. § 613A(b)(2)(A). Under the disputed price adjustment clause in the SWEPCO contract, any price increases were required "to be determined *as of the first day of each year*, and to remain in effect . . . *for the calendar year thereafter*." PX 12b at SWEF0000009 (emphasis added). Pursuant thereto, the contract price was adjusted to the sum of $0.29659829 per MMBtu,[(347)] effective January 1, 1975, and remained at exactly that price throughout the remainder of the year 1975, as evidenced by each and every one of the monthly invoices that Exxon submitted to SWEPCO during that year.[(348)] Accordingly, given that the aforesaid contract price did not increase at *any* time during 1975, subsequent to the February 1, 1975 cut-off date for the fixed contract exception, the court holds that the SWEPCO contract qualified as a "fixed contract," within the meaning of § 613A(b)(2)(A), during the taxable year 1975. Therefore, we hold, further, that all of the natural gas that Exxon sold to SWEPCO in 1975, pursuant to the contract in issue, was eligible for percentage depletion. § 613A(b)(1)(B).

CONCLUSION

Given all of the foregoing, the court summarizes its holdings herein, as follows:

1. The "representative market or field price" (RMFP), within the meaning of Treas. Reg. § 1.613-3(a), was $0.6831 per Mcf, with respect to Exxon's production of gas well gas, representing 90.26% of the total volume (Mcf) of the disputed gas production from the 369 Exxon properties in issue, during the taxable year 1975. A detailed computation of said RMFP is contained in Appendix A, *infra*.

2. On this record, Exxon has failed to prove an RMFP with respect to the 1975 casinghead gas production in dispute, representing the remaining 9.74% of the total volume of the gas production from the 369 Exxon properties in issue. Consequently, given said failure of proof, such casinghead gas is ineligible for percentage depletion, relative to the taxable year 1975.

3. None of the natural gas that Exxon sold during 1975, pursuant to its contract with Houston Lighting & Power Co. (HL&P), was eligible for percentage depletion, on the ground that such gas failed to qualify as "natural gas sold under a fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A).

4. All of the natural gas that Exxon sold during 1975, pursuant to its contract with Southwestern Electric Power Company (SWEPCO), constituted "natural gas sold under a fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A), and as such, was eligible for percentage depletion.

5. Given defendant's concession that all of the natural gas that Exxon sold during 1975, pursuant to the remaining 16 contracts in issue, was "natural gas sold under a fixed contract," within the meaning of §§ 613A(b)(1)(B) and 613A(b)(2)(A), *supra*, all of the gas sold under said 16 contracts was eligible for percentage depletion.

The basic remaining factual issue to be decided, in view of all of the foregoing, is the amount of "the gross income from the property" (GIFP), within the meaning of § 613A, on which Exxon's percentage depletion allowance for the taxable year 1975 shall be computed, under §§ 613 and 613A, with respect to the natural gas that Exxon produced from its 369 properties located in the Texas Gulf Coast and East Texas region and sold pursuant to 17 contracts that qualified as fixed contracts under §§ 613A(b)(1)(B) and 613A(b)(2)(A).

In that connection, on November 2, 1999, the court held a status conference in open court for the sole purpose of encouraging the parties to stipulate to said basic factual issue as well as all collateral and computational issues necessary to reach the ultimate determination as to whether Exxon is entitled to a tax refund for the taxable year ending December 31, 1975.

The parties unhesitantly agreed to the request of the court, and that they would do so within two weeks from the issuance of subject opinion, *i.e.*, on or before December 16, 1999.

Agreeable to the foregoing, so as to facilitate the expeditious resolution of all remaining issues and to permit the court to enter judgment in this case, the parties are accordingly requested and directed to stipulate to the following respecting Exxon's 1975 taxable year:

i. that the aggregate tentative GIFP with respect to all 369 of the properties in issue, allocable to Exxon's 1975 sales of "fixed contract" gas, was $________________;

ii. that the total royalties incurred by Exxon, relative to its 1975 sales of "fixed contract" gas produced from said 369 properties, were $______________________;

iii. that the GIFP, *supra*, before application of the taxable income limitation under § 613A(a), was $_______________ (*i.e.*, the aggregate tentative GIFP allocable to fixed contract gas, minus the allocable royalties, *supra)*;

iv. all other computational factual issues, including but not limited to those necessary to arrive at Exxon's corrected taxable income; tax liability, taxes and interest previously paid; and such tax refund and interest due, if any, based on all of the foregoing; and

v. to draft an order permitting the court to enter judgment incorporating the relevant foregoing, agreeing to such tax refund and interest due Exxon for the 1975 taxable year, if any, consistent with the foregoing holdings.

IT IS SO ORDERED.

1. Except as otherwise stated, section references herein are to the Internal Revenue Code of 1954 (the "Code"), Title 26 of the United States Code, as in effect for plaintiff's taxable year ended December 31, 1975. Jurisdiction is premised on § 6532(a) and § 7422(a) of the Code, and on 28 U.S.C. §§ 1346(a) and 1491.

As used herein, "PX" denotes a Plaintiff's Exhibit received in evidence, "DX" means a Defendant's Exhibit, and "Tr." refers to the trial transcript. "SubX" denotes a sub-exhibit contained within an expert witness' report, itself in evidence, this being reflective of the nomenclature settled upon at trial.

2. Two basic prerequisites to the allowance of a depletion deduction are satisfied by the parties' joint stipulations that each of those 369 properties was a "property" within the meaning of § 614 and Treas. Reg. § 1.611-1(d)(1), and, further, that Exxon owned an "economic interest," within the meaning of Treas. Reg. § 1.611-1(b), in each of those 369 properties. PX 22 at ¶ 1-3 (Joint Stipulation of Facts, filed August 26, 1997).

3. Those 18 customers (with the exhibit number of each contract noted thereafter) were Celanese Corp. (PX 12a), Southwestern Electric & Power (SWEPCO) (PX 12b), E.I. DuPont -- Beaumont (PX 12c), E.I. DuPont -- Sabine (PX 12d), Lubrizol Corp. (PX 12e), Texas Eastman Co. (PX 12f), Texas Power & Light (PX 12g), Lone Star Steel Co. (PX 12h), Suntide Refining Co. (PX 12i), Armco Steel Co. (PX 12j), the Texas Department of Corrections (PX 12k), Pittsburgh Plate Glass (PX 12l), Southwestern Oil & Refining (PX 12m), Gulf States Utilities (PX 12n), Houston Lighting & Power Co. (HL&P) (PX 12o),

Neches Butane Products Co. (PX 12p), United Texas Transmission Co. (PX 12q), and Lone Star Gas Co. (PX 12r).

4. Unless otherwise indicated, citations herein to the Court of Federal Claims' decision regarding the computation of Exxon's percentage depletion deduction for the 1974 taxable year, 33 Fed. Cl. 250, shall be to findings of fact and conclusions of law not reversed on appeal.

5. Natural gas liquids are made up of longer, heavier hydrocarbon molecules than methane. For example, ethane, the second lightest hydrocarbon in natural gas, has two carbon atoms and six hydrogen atoms. Propane, the third lightest hydrocarbon, has three carbon atoms and eight hydrogen atoms, and so on. The heavier natural gas liquids, known collectively as "natural gasoline," contain five or more carbon atoms and a commensurately greater number of hydrogen atoms.

6. Although such limitations have application to the year 1975, as well as 1974, they are not addressed herein. One such limitation is that "the gross income from the property" must be computed exclusive of "an amount equal to any rents or royalties paid or incurred by the taxpayer in respect of the property." § 613(a). In addition, the Code provides that the allowance for percentage depletion "shall not exceed 50 percent of the taxpayer's taxable income from the property (computed without allowance for depletion)." Id. By this opinion, we do not reach the ultimate computation of the "gross income from the property" with respect to the 369 Exxon properties in issue. Rather, the court herein addresses the determination of the RMFP, on which the gross income from each such property is based.

7. Most recently, here at bar, in denying the Government's pre-trial motion for summary judgment, as discussed below, this court examined Treas. Reg. § 1.613-3(a) at length, and reaffirmed its validity. Exxon, 40 Fed. Cl. at 83-91. In so doing, we held that because Treas. Reg. § 1.613-3(a) originates in an express grant of rulemaking power by Congress, it is "legislative" in character and effect. Id. at 84-85 (citing Chevron U.S.A., Inc. v. Natural Resources Defense Council, 467 U.S. 837, 843-44 (1984); Commissioner v. Portland Cement Co. of Utah, 450 U.S. 156, 169 (1981); Schuler Industries, Inc. v. United States, 109 F.3d 753, 755 (Fed. Cir. 1997); Exxon, 102 T.C. at 727).

8. As decisions of the former Court of Claims, Hugoton I, Hugoton II, and Panhandle are binding precedent for this court, as well as for the Federal Circuit unless overruled by that court *en banc*. South Corp. v. United States, 690 F.2d 1368 (Fed. Cir. 1982).

9. Compare Exxon, 102 T.C. at 744 & n.28 (holding, limited to the facts of the case, that the use of the RMFP method to determine Exxon's percentage depletion allowance for the year 1979, "would be unreasonable" in that the RMFP would be "five times the actual sales proceeds from the sale of gas"). Here at bar, of course, the Tax Court's considered judgment notwithstanding, we are bound by the Federal Circuit's holding in Exxon I, *supra*.

10. See also Panhandle, 187 Ct. Cl. at 150, 408 F.2d at 704 (noting "the practical difficulties involved in selecting proper sample purchase contracts relating to wellhead sales used in determining [the RMFP and] the limitations on the availability and accuracy of sources of relevant information concerning these sales"); Hugoton I, 161 Ct. Cl. at 280, 315 F.2d at 871 ("[I]t is indeed a difficult task to construct a market price at which particular gas would have sold had it been marketed at the wellhead.").

11. Of the $82,059,252 of depletion deductions originally claimed by Exxon, $57,826 represents cost depletion and $82,001,426 represents percentage depletion. PX 22 at 23, 27-40. Defendant does not contest Exxon's entitlement to the $57,826 of cost depletion deductions.

12. Defendant emphasized February 1, 1975, because only contracts in effect on that date were eligible to

qualify under the fixed contract exception. § 613A(b)(2)(A).

13. Nothing in the forthcoming synopsis should be read to change, or conflict with, any observations or the literal holding in the court's summary judgment opinion.

14. For practical reasons, we defer any decision as to the GIFP issue. In essence, Exxon's GIFP computation takes its proposed RMFP and applies said RMFP to the gas produced by the 369 Exxon properties in issue during 1975. With certain revised assumptions and methodology, the Government's GIFP computation does much the same. The GIFP computation is somewhat complicated by the fact that not all of the gas produced from the 369 Exxon properties was sold pursuant to the 18 long-term contracts in issue, such that intricate accounting allocations must be made. Due to said complexity of the GIFP computation, each party submitted extensive sets of accounting workpapers, created by means of computer spreadsheet software, at trial. Because the GIFP computation hinges upon the RMFP, and the RMFP determined by the court herein differs from the RMFPs averred by either of the parties, the GIFP must be recomputed on the basis of the RMFP determined by the court. Moreover, the GIFP computation is also modified by the court's determination herein, *infra*, that the HL&P contract failed to qualify as a "fixed contract." Thus, upon the issuance of this opinion, deciding the merits of the RMFP and the HL&P/SWEPCO contract issues, the parties will perform the ministerial task of recomputing their respective proposed GIFPs, and will attempt to stipulate as to the amount of the GIFP. If, and only if, that effort fails, the parties will submit their revised GIFP workpapers for the court's consideration, after which the court will issue a second opinion deciding the GIFP issue.

15. The Texas Railroad Commission is the state agency that regulates the production and transportation of oil and gas in the State of Texas. See Exxon I, 33 Fed. Cl. at 259 n.5.

16. Mr. Ellis' written report is based upon a sample of 2,059 transactions and expresses an opinion that the RMFP is $0.77/Mcf. PX 6 at 28. At trial, however, it emerged that one such transaction did not meet Mr. Ellis' criteria for inclusion in his study and had been included in his RMFP sample in error. Tr. 386-87. Thus, Mr. Ellis withdrew that transaction, designated with the "WGA ID number" G1062, from his RMFP sample. Tr. 890-91. This reduced his RMFP sample to 2,058 transactions, and reduced his RMFP to $0.7645/Mcf. The "WGA ID number" is a unique number that Mr. Ellis assigned to each transaction in his RMFP sample, for ease and consistency of reference. The acronym "WGA" stands for Willis, Graves & Associates, his consulting firm. Herein, the court adopts the convention of referring to the transactions in Mr. Ellis' RMFP sample by their respective WGA ID numbers.

17. In its proposed findings of fact, Exxon asserts that *all* of the pertinent pipeline company gas purchase contracts and related files are in the record. PPF at 20, ¶ 61. That is simply untrue. Relative to the 2,058 transactions in his RMFP study, Mr. Ellis testified that he had 1,557 contract files available, of which only 1,037 files were, in his view, "reasonably complete." Tr. 931. Moreover, Appendix I to Mr. Ellis's report (PX 6) purports to cross-reference each of the 2,058 transactions in his RMFP sample to the underlying documentary evidence, but curiously cites no contract file in connection with many such transactions. Mr. Ellis admitted that the absence of such a cross-reference means that there is no contract file in evidence. Tr. 967-68, 972-73.

18. All three men were responsible for the negotiation and administration of gas purchase contracts. In 1975, Mr. Buie was a senior gas contract representative employed by HPL. Mr. Eakin was a manager in the gas supply and contract administration departments of Lo-Vaca. Mr. Hague was a manager in United's gas acquisition department.

19. Transportation, of course, involves the situation in which the producer's gas "is transported from the premises prior to sale," as opposed to being sold "in the immediate vicinity of the well." Treas. Reg. §

1.613-3(a). Compression is a mechanical process by which the pressure of the gas is increased, above the natural pressure at which it flows from the producer's well, so as to effectuate the delivery of the gas into the purchaser's pipeline. Dehydration is a chemical process that removes water vapor from natural gas. Exxon I, 88 F.3d at 978; 33 Fed. Cl. at 257, 275-76. All three of the aforesaid post-extraction activities are examined at greater length, *infra*.

20. Tr. 1845-46, 1849-50.

21. In addition, Mr. Charles Brown, another registered professional engineer, reviewed the pipeline company contract files relating to 31 of the transactions in Mr. Ellis' 2,058-transaction RMFP sample, in order to determine whether those 31 transactions qualify as wellhead sales includible in the RMFP computation. However, on cross-examination, Mr. Brown was unable to establish any plausible factual basis for his own conclusions, many of which he recanted while on the witness stand. Tr. 1694, 1695, 1721. Given the irreparable destruction of his credibility at trial, the court assigns no probative weight to Mr. Brown's report and testimony.

22. To explain the nature of a "volume-weighted" average price, such a calculation takes account of the fact that natural gas is commonly measured volumetrically, *i.e.*, by reference to the physical volume that gas occupies at a standard temperature and pressure. In volumetric terms, the abbreviation Mcf denotes 1,000 cubic feet of gas, MMcf denotes one million cubic feet of gas, Bcf denotes one billion cubic feet of gas, and so on. DX 47. The RMFP is traditionally stated in volumetric terms. See, e.g., Exxon I, 88 F.3d at 979 (holding that 1974 RMFP was $0.39/Mcf). Thus, the depletable "gross income from the property" equals the RMFP, per Mcf, multiplied by the units of gas produced, in Mcf. Id. at 971 n.2. Given a valid RMFP sample, consisting of qualifying sales of raw natural gas, the volume-weighted RMFP is determined as follows. First, the total dollar price of the gas sold in all of the subject transactions "is derived by multiplying the volume of each transaction by the [per-Mcf] price for that transaction, and summing the resulting figures for all transactions." Id. at 979 n.9. Second, the volume-weighted average price "is derived by dividing this total price . . . by the total volume" of gas sold in all of the subject transactions. Id. Volume-weighted averaging acknowledges that a transaction involving one Bcf of gas, for example, logically should exert a greater influence on the RMFP than a transaction involving one Mcf.

23. As noted herein, *supra*, Mr. Ellis withdrew transaction G1062 from his original primary RMFP sample. Tr. 890-91. The figures above are derived by subtracting the volume and value of the gas in transaction G1062 (PX 6, SubX G, at 19) from the total volume and value of the gas represented in Mr. Ellis' original 2,059-transaction RMFP sample (PX 6, SubX G, at 51).

24. Exxon's tabulation of its so-called "pristine" RMFP sample was not received in evidence at trial, but rather, presented in Exxon's post-trial proposed findings of fact. PPF at 25-27, ¶¶ 74-76; Transcript of Closing Arguments, June 22, 1998, at 11-12 (counsel's description of sample as "pristine"). The volume and value figures shown above correct two minor addition errors in Exxon's tabulation of its "pristine" RMFP sample, without effect on the proposed RMFP.

25. This vast disparity between conclusions based on the same data brings to mind that old adage respecting statistics. See Datascope Corp. v. SMEC, Inc., 14 U.S.P.Q. 1071, 1990 WL 10345, at *5 n.3 (D.N.J. 1990) (quoting 19th-century British Prime Minister Benjamin Disraeli). See also West v. Swift, Hunt & Wesson, 847 F.2d 490, 492 n.2 (8th Cir. 1988) (same); United States v. Jackson, 825 F.2d 853, 875 n.2 (5th Cir. 1987).

26. A separator is a simple, gravity-driven mechanical device, normally situated in close proximity to the well, that removes free liquids, *i.e.*, water in liquid form and "condensate" (liquid hydrocarbons

chemically similar to crude oil), from the raw gas wellstream. See Exxon I, 33 Fed. Cl. at 257 (similar findings as to 1974). Separation precedes, and is an activity distinct from, both dehydration and processing. Whereas dehydration is a *chemical* process that removes *gaseous* water (*i.e*., water vapor) from the natural gas, separation is a *mechanical* process that removes *liquid* water from the gas. Exxon I, 33 Fed. Cl. at 276-77, 88 F.3d at 978. Similarly, as already explained, *supra*, processing extracts *liquefiable* hydrocarbons (*i.e*., hydrocarbons in a gaseous state, commonly referred to as "natural gas liquids") from the gas. In contrast, separation removes *liquid* hydrocarbons from the gas.

27. The Government's three RMFP computations, on the other hand, disregard the Federal Circuit's "preferable" method, making no transportation, compression, or dehydration adjustments.

28. Indeed, by all indications, we perceive that the record amassed in this case far outstrips the record in Exxon I. Before trial, in a telephone conversation with the court's staff on January 8, 1998, counsel for Exxon represented that Exxon I was tried on the basis of summaries of the documentation underlying the opinions and reports of the parties' expert witnesses, and that such underlying documents were only selectively offered into evidence. Moreover, counsel for Exxon initially intended to try the present case in similar fashion, counsel for defendant having expressed a willingness to go along with such an approach. Transcript of Pre-Trial Conference, held December 18, 1997, at 12-13, 17. As explicated below, Exxon abandoned the aforesaid approach, electing instead to put all of its underlying documentation in the record.

29. Transcript of Pre-Trial Conference, held December 18, 1997, at 10. By comparison, the Government's exhibits fill just two boxes. The unparalleled volume of the documentary evidence in this case exceeds the capacity of the normal document storage facilities available to the Clerk's Office of the Court of Federal Claims. Thus, said documentary record is stored on 15 large floor-to-ceiling shelving units, temporarily on loan to the court from Exxon, installed in a secluded hallway behind the courtroom in which the trial was held.

30. Given the foregoing, by an order filed on October 27, 1998, the court called a status conference for the purpose of discussing how to facilitate the expedient completion of the court's review of the record. In an attachment to that order, we documented the nature and extent of the irrelevant surplusage found in the record and, further, expressed our dismay at the parties' handling of this aspect of the case. Attachment to Order filed October 27, 1998, at 1-6 & n.17. At the subsequent status conference, held on October 30, 1998, the parties ventilated certain proposals for culling the irrelevant surplusage from PX 14a and PX 14b. Unfortunately, however, no action was taken in this respect.

31. Before trial, counsel for Exxon candidly predicted what later became self-evident -- that it would be impracticable to address all 2,058 transactions at trial. Transcript of Status Conference, held January 13, 1998, at 11. In fact, at trial, only about 23 such transactions were meaningfully examined as to their qualification for inclusion in the RMFP computation. Roughly another 39 such transactions were mentioned at trial, but only in passing or in cursory fashion.

32. Messrs. Buie and Eakin allegedly testified from their personal recollection of various gas purchases that their respective former employers, HPL and Lo-Vaca, made in 1975. But see Tr. 476-83 (Buie's imperfect recollection of transaction G0875), 512-14 (same as to transaction G1105), 526-35 (same as to transactions G0806 and G0807). Similarly, Mr. Eakin purportedly testified from his first-hand knowledge of four gas purchases that Lo-Vaca, his former employer, made in 1975, *i.e*., transactions L0336 (Tr. 691-763, 789-90), L0170 (Tr. 765-84), L0498 (Tr. 784-810), and L0107 (Tr. 814-22). But see Tr. 692-95, 721, 733-39, 758-61, 789-90 (Eakin's lack of recollection of many pertinent facts in connection with transaction L0336).

Exxon's only other witness who gave any testimony concerning the qualification of specific transactions for inclusion in the RMFP computation -- Mr. Ellis -- possesses no personal knowledge of any facts, as of 1975, relating to any transaction in controversy, inasmuch as he had no involvement with the natural gas industry prior to 1980. Tr. 849-50. Consequently, each of his conclusions regarding the 1975 RMFP computation is an expression of his naked opinion, not a proven fact in evidence.

33. Throughout the course of these proceedings, the court has implemented certain practical measures in order to ameliorate the intrinsic difficulty of dealing with a documentary record of this magnitude. For example, we convened a status conference on January 13, 1998, for the sole purpose of dealing with the many logistical issues relating to how such a massive volume of documentation would be handled at trial. Also, in trying this case, the court brought in a second law clerk whose sole job was to organize and keep track of the documentary exhibits. Most importantly, by an order filed on December 2, 1997, the court directed that the parties' expert witnesses to cross-reference their written reports to the underlying documentary evidence on which their opinions rest. We subsequently reiterated that directive at the pre-trial conference, held December 18, 1997 (Tr. 11-12, 23-24), and at trial (Tr. 975-78, 2772). Exxon's experts responded by submitting workpapers that purport to cross-reference their reports to the underlying evidence. See, e.g., PX 6, SubX I (Ellis report). In many cases, however, such cross-references are incomplete or imprecise, *i.e.*, eschewing pinpoint citations in favor of sweeping citations that reference hundreds, or even thousands, of pages. Somewhat more useful is a comprehensive exhibit index that Exxon submitted to assist the court in locating exhibits, and portions thereof, within Exxon's 268 boxes of evidence. Index to Plaintiff's Trial Exhibits, filed June 4, 1998.

34. We find it instructive that it was opinion testimony regarding the valuation of natural gas -- the very essence of the RMFP computation -- that gave rise to the two most authoritative invocations of this evidentiary principle. See Sartor, 321 U.S. at 627-29 (opinion testimony as to the wellhead price of natural gas); Dayton Power & Light, 292 U.S. at 299 (opinion testimony as to the valuation of natural gas leases).

35. The Hugoton Embayment has, of course, been described at great length in the Hugoton, Panhandle, and Shamrock cases. Hugoton I, 161 Ct. Cl. 274, 315 F.2d 868 *passim*; Hugoton II, 172 Ct. Cl. 444, 349 F.2d 418 *passim*; Panhandle, 187 Ct. Cl. at 143-160, 208-37, 408 F.2d at 699-709; Shamrock, 35 T.C. 979 *passim*.

36. To prevent such commingling, pipeline companies operating in both interstate and intrastate commerce segregated their interstate and intrastate pipeline systems, in separate corporate subsidiaries, with no physical interconnections between the two systems. Moreover, contracts for the purchase and sale of gas in the Texas intrastate market generally contained provisions barring the pipeline company purchaser from transporting or reselling the gas in interstate commerce.

In 1975, the major interstate pipeline companies operating in the Texas Gulf Coast/East Texas region included Arkansas Louisiana Gas Co., Columbia Gas Transmission Co., Florida Gas Transmission Co., Natural Gas Pipeline Company of America, South Texas Natural Gas Gathering Co., Southern Natural Gas Co., Tenneco, Inc., Texas Eastern Transmission Corp., Transcontinental Gas Pipe Line Corp., Trunkline Gas Co., and United Gas Pipeline Co. Major intrastate pipeline companies in the Texas Gulf Coast/East Texas region included Channel Industries Gas Co., Delhi Gas Pipeline Corp., Houston Pipe Line Co., Lone Star Gas Co., Lo-Vaca Gathering Co. (Lo-Vaca), Tejas Gas Corp., and United Texas Transmission Co.

37. See Exxon I, 33 Fed. Cl. at 260-61. Prior to the late 1960s and early 1970s, Permian Basin gas was sold primarily in interstate commerce, for consumption on the West Coast and in the North Central states.

38. Tr. 43 (Pohler estimate of percentage of Permian Basin gas moving eastward). In 1975, the total natural gas production in the State of Texas was approximately 8,066 Bcf in 1975. Railroad Commission of Texas, Oil and Gas Division, *Annual Production By Active Fields -- 1975*, at 5, reproduced at DX 7, SubX C. Roughly 47% of that gas production, or about 3,808 Bcf, came from the Texas Gulf Coast/East Texas region, *i.e*., Railroad Commission Districts 2 through 6. Id. Another 30%, or about 2,456 Bcf, came from Railroad Commission Districts 7C and 8, in which the Permian Basin is located. Id. The remainder of Texas gas production in 1975 came from the Fort Worth Basin and the Texas Panhandle. Id.; Tr. 42-43. Given 2,456 Bcf of Permian Basin gas production, the 25% to 30% of such gas moving eastward to the Texas Gulf Coast equated to roughly 614 Bcf to 737 Bcf. Thus, approximately 14% to 16% of the total gas supply in the Texas Gulf Coast/East Texas region came from the Permian Basin (*i.e*., 14% = 614 ÷ (614 + 3808), whereas 16% = 737 ÷ (737 + 3,808)).

39. Mr. Buie noted that in 1972, Texas produced 38%, and consumed 20%, of the total gas produced in the continental U.S. (*i.e*., excluding Alaskan gas production). As explained above, the heavy industrial consumption of gas in the Houston area led Exxon to build EGS.

40. Tr. 313-14; PX 2, SubX B. HPL's monthly WACOG escalated from $0.175/Mcf in January of 1970 to $1.51/Mcf in October of 1975. Id. Similarly, Lo-Vaca Gathering Company, another large intrastate pipeline company, had a 1975 WACOG of $1.36/Mcf. PX 4 at 17 (Eakin report). Computed on a monthly basis, Lo-Vaca's WACOG increased from $0.27/Mcf in September of 1973 to $1.95/Mcf for new contracts entered into in 1975. Id.

41. In a rising market, the WACOG tends to lag behind the current market price, because it represents a pipeline company's entire mix of contracts -- new, higher-priced contracts, as well as old, lower-priced contracts.

42. PX 3, SubX B, at 8; Texas Energy and Natural Resources Advisory Council, *Texas Energy History: 1979 Update*, at 115 (hereafter, "TENRAC Report"), reproduced at DX 5, SubX 5 (noting that between 1974 and 1975, the "average wellhead value" of intrastate gas went from $0.347/Mcf to $0.628/Mcf, an increase of roughly 81%, whereas the "average wellhead value" of interstate gas went from $0.269/Mcf to $0.383/Mcf, an increase of only about 42%).

43. PX 3 at 9; Tr. 907-08; University of Texas at Austin, *Field Handling of Natural Gas*, at 1 (3d ed. 1972) (noting that the nation was "facing an acute crisis in gas supply" caused, in part, by "the low field prices for natural gas under FPC regulations"), reproduced at PX 1, SubX 9.

44. Within the industry, such price redetermination clauses are often referred to as "favored nations" clauses. See Hugoton I, 161 Ct. Cl. at 319 & n.35, 315 F.2d at 894 & n.35; Exxon I, 33 Fed. Cl. at 261. When the contractually specified time for a price redetermination arrived, the pipeline company and producer typically would execute a short letter agreement to memorialize the redetermined price thereafter in effect. Most such letter agreements set forth the computation of the redetermined price, reciting the prices observed in two or three third-party transactions.

45. Tr. 615-16. See also PX 2 at 14; PX 4 at 10.

46. The court's examination of the pipeline company contract files in PX 14a and PX 14b confirms Mr. Eakin's account. Such contract files are replete with price redetermination letter agreements, of which at least several hundred bear 1975 dates. Given the sheer volume of price redetermination documentation in the record, it is incontrovertible that the price of intrastate gas in the Texas Gulf Coast/East Texas region rose sharply throughout the 1970s, including 1975.

47. We think, moreover, that McMullan is most plausibly read as an "easy" collateral estoppel case, in which the sameness of the issues presented by the two suits was so clear-cut as to allow the court to dispose of the question in perfunctory fashion. See McMullan, 231 Ct. Cl. at 382, 686 F.2d at 919 (addressing said point in two sentences). Further, the three Court of Claims judges that decided McMullan were also members of the *en banc* panel that had heard and decided Wilmington. Compare McMullan, 231 Ct. Cl. at 379, 686 F.2d at 917, with Wilmington, 221 Ct. Cl. at 689, 610 F.2d at 704. Those three judges' familiarity with the record in Wilmington no doubt helped them make short work of the collateral estoppel issue in McMullan.

48. PX 2 at 12 (Buie report). Mr. Buie opined that historically, there were three separate and distinct gas markets in Texas -- the Texas Panhandle, West Texas, and the Texas Gulf Coast/East Texas region(49)

49. Tr. 308-10; PX 2 at 4. -- " " -

50. We note, moreover, that the trial court in Exxon I found that gas processing, *i.e.*, for the extraction of liquefiable hydrocarbons, "in 1974 was very profitable and contributed significantly to the value of the gas produced." Exxon, 33 Fed. Cl. at 258. Here at bar, in stark contrast to the foregoing, the consensus view expressed by Exxon's experts is that gas processing was generally *un*profitable in 1975. Tr. 70-72, 123, 190-95, 199-200 (Pohler), 319-20 (Buie), 619 (Eakin). If the opinions of Exxon's experts are accepted as true, this surely suggests a material change in the business climate of the Texas natural gas industry between 1974 and 1975.

51. For example, in connection with the definition of the relevant market area, an issue of potential significance that arose at trial was the extent, if any, to which market conditions in the Texas Gulf Coast/East Texas region, Exxon's proposed market area, were influenced by the gas that was being produced in the Permian Basin and transported eastward by pipeline to the Texas Gulf Coast area in 1975, *supra*. However, when asked about such Permian Basin gas, Mr. Buie was generally vague and unresponsive. Indeed, for a witness with over 40 years of experience in the Texas natural gas industry, qualified as an expert in purchasing and pricing natural gas in Texas, Mr. Buie displayed a remarkably selective lack of recollection concerning the Texas natural gas industry outside of the Texas Gulf Coast/East Texas region. To name but one example, Mr. Buie professed ignorance concerning the Permian Basin business operations of Intratex Gas Company, an affiliate of Houston Pipe Line Company (HPL), his former employer. Tr. 396-97, 399. Yet, Mr. Buie later admitted: "I did at one time become *president* of Intratex Gas Company." Tr. 429-30 (emphasis added). Similarly, on cross-examination, Mr. Pohler disclaimed any significant personal knowledge of pipelines located outside the Texas Gulf Coast/East Texas region, *i.e.*, the pipelines that were constructed in the late 1960s and early 1970s to transport Permian Basin gas eastward to the Texas Gulf Coast, and certain pipelines that run between the cities of Fort Worth and Houston. Tr. 158-62. As to Mr. Ellis, his opinion that no significant changes occurred between 1974 and 1975 that would affect the definition of the relevant market area was just that -- a naked opinion -- inasmuch as he had no personal involvement with the Texas natural gas industry until 1980. Tr. 849-50. Further, he admitted that he had never done a formal study of the dynamics of the Texas natural gas industry in the mid-1970s, had never published a paper on that subject, and had not consulted any authoritative treatise on that subject. Tr. 918-20.

52. Strictly speaking, as Exxon acknowledges in its brief, the quoted statement in Panhandle has nothing to do with collateral estoppel. However, we find it appropriate to address this point in conjunction with our discussion of the doctrine of collateral estoppel, which goes to essentially the same question, *i.e.*, whether the market area determined in Exxon I "should be subject to revision year after year." Id.

53. At trial, Mr. Pohler conceded that the Texas intrastate gas market in 1975 "was not as stable a market as it was in the 1960s." Tr. 157. See also PX 4 at 5-7 (Eakin report, to similar effect).

54. See also Hugoton II, 172 Ct. Cl. at 450 & n. 9, 349 F.2d at 421 & n. 9 (finding that the marketability of natural gas is influenced by the ease with which the producer's wells can be connected to the purchaser's pipeline system); Panhandle, 187 Ct. Cl. at 156, 408 F.2d at 707 (finding that a geographical "area . . . interlaced with competing pipelines" constituted a suitable market area for purposes of the RMFP computation); Exxon I, 33 Fed. Cl. at 260 ("In general, the more pipelines in a market area, the better the price and contract provisions a producer could expect."). The physical proximity of the producer's gas properties to the pipelines of prospective purchasers is, of course, one of the factors that must be considered in relation to the issue of gas comparability, which we take up separately in the next section of this opinion.

55. This is so because the term "locality," as used in Hugoton I, does not establish "a rigid, fixed size" for the relevant market area. Panhandle, 187 Ct. Cl. at 155, 408 F.2d at 706. Thus, in Hugoton II, "acreage lying within 30 miles of the taxpayer's acreage provided sufficient sales of comparable gas from which to compute a representative market price." Panhandle, 187 Ct. Cl. at 148, 408 F.2d at 702 (citing Hugoton II, 172 Ct. Cl. at 450 n.9, 349 F.2d at 421 n.9). Yet, in noting this aspect of Hugoton II, the Court of Claims observed: "There is, of course, no magic in the figure of 30 miles for the courts have not hesitated to go many miles further away to find comparable sales." Panhandle, 187 Ct. Cl. at 148, 408 F.2d at 702 (citing Cannelton, 364 U.S. at 80 (comparable sales identified 140 miles away from taxpayer's mines)).

56. Specifically, the parties have stipulated that 15 of the Exxon properties in issue

were located in District 2, 136 properties were in District 3, 49 properties were in District 4,

5 properties were in District 5, and 164 properties were in District 6. PX 19 at 8-16.

57. The heavy concentration of gas pipelines throughout the Texas Gulf Coast, *i.e.*, "Pipeline Alley," and the slightly less concentrated but nonetheless substantial network of pipelines in East Texas, are convincingly illustrated by several maps in the record, enlargements of which have been submitted as demonstrative exhibits. PX 1 at SubX 2, 13, 14; PX 5 at SubX 26. See also Exxon I, 33 Fed. Cl. at 259 & n.6, 260-62 (similar findings as to 1974). Although Exxon I is not entitled to conclusive weight, with respect to our determination of the relevant market area in 1975, given our holding that the doctrine of collateral estoppel is inapplicable, *supra*, Exxon I's holding as to the relevant market area in 1974 is nonetheless entitled to consideration as an instructive, albeit nonobligatory, precedent.

58. A map in Mr. Pohler's report shows thousands of gas wells, depicted as diminutive red dots, scattered throughout the entire Texas Gulf Coast/East Texas region. PX 1, SubX 2; Tr. 39. Moreover, a second map in Mr. Pohler's report compares the locations of: (i) the Exxon gas wells relating to the 369 properties in issue; and (ii) the gas wells relating to the 2,058 transactions included in Exxon's primary RMFP sample, all of which took place in the Texas Gulf Coast/East Texas region. PX 1, SubX 22. Enlargements of both maps are in the record as demonstrative exhibits. For purposes of computing an RMFP, it is evident that had Exxon been free to sell its gas at the wellhead, the gas wells in Exxon's primary RMFP sample were sufficiently close to Exxon's 369 gas properties so as to constitute potential competition. See Hugoton II, 172 Ct. Cl. at 450 n.9, 349 F.2d at 421 n.9 (comparable gas sales 30 miles away from taxpayer's gas production); Cannelton, 364 U.S. at 80 (comparable sales 140 miles away from taxpayer's mines).

59. In addition to the evidence cited above, the existence of such a market in the Texas Gulf Coast/East Texas region is implied by Exxon's primary RMFP sample, which consists of 2,058 purported wellhead sales of comparable gas in that region. Although there is considerable room for controversy over the qualification of most of those 2,058 transactions for inclusion in the RMFP computation, the sheer number of transactions is strongly indicative of an active, competitive natural gas market.

60. For example, with respect to the Texas intrastate gas market in 1975, Mr. Welp opined that it was "possible" to enter into gas exchange transactions, whereby one pipeline company would make an exchange of gas with another pipeline company, in order to effectuate the delivery of gas to a customer to whom the first pipeline company was not connected. Mr. Welp opined, further, that it was "possible" to pay an intrastate pipeline company to furnish transportation for hire to gas producers, meaning that the pipeline would not take title to the gas but, rather, would transport such gas to another locality for delivery to a remote purchaser, at the direction of the seller of the gas. Tr. 1822. Given the foregoing, Mr. Welp opined that any gas producer located in the Texas Gulf Coast/East Texas region, including Exxon, "could" market its gas in the intrastate market to customers located anywhere else in Texas. Similarly, Mr. Welp opined that any gas producer in Texas, including Exxon, "could" market its gas in the interstate market to customers located anywhere in the United States. Moreover, Mr. Welp opined that any pipeline company in the Texas Gulf Coast/East Texas region, including Exxon, "could" purchase gas anywhere in Texas and have such gas delivered anywhere in Texas. Tr. 1827-29; DX 7 at 5.

Such opinions, couched in purely conjectural terms, are without probative force. The mere possibility that Texas gas producers and the intrastate pipeline companies, wherever situated, could *hypothetically* use gas transportation and exchange agreements to buy, sell, and deliver gas anywhere else in Texas says nothing about whether such transportation and exchange arrangements did, *in fact*, unify the State of Texas into a single, statewide market for natural gas in 1975. Mr. Welp made no attempt to show how frequently such transportation and exchange transactions took place in Texas in 1975, nor did he attempt to quantify the total volume of gas transported within Texas pursuant to such arrangements.

61. Mr. Welp admitted that he did not prepare said tabulation, designated as subexhibit E in his report (DX 7), nor subexhibits F and H thereto. Rather, the author of those three subexhibits was a Dr. Milton Holloway, Ph.D., of Economic Resources, Inc., Austin, Texas, whom the Government failed to call as a witness. Tr. 1791-98. Thus, Mr. Welp admitted that he could not verify the accuracy of the information presented in subexhibit E to his report. Tr. 1792. In addition to the foregoing, the court notes that the information in Mr. Welp's subexhibit E is presented in a format that we find simply incomprehensible.

62. Mr. Welp admitted that his study fails to show where any of the gas in question was sold by the producers of such gas, *i.e.*, at the wellhead or elsewhere. Tr. 1856-57. Further, he admitted that only pipelines, not gas producers, were parties to the 1975 gas exchange transactions considered in his study. Tr. 1868. Moreover, Mr. Welp conceded that his study fails to demonstrate that gas producers sold gas to remote purchasers by entering into transportation for hire agreements with pipelines. Tr. 1863. In addition, with respect to the gas transportation and exchange transactions considered in his study, he admitted that he did not know who had title to the gas being transported pursuant to such arrangements. Tr. 1855-56, 1864, 1869.

63. See, e.g., PX 14b at H0105868 (price redetermination clause referencing District 2); PX 14a at H071487 (District 3); PX 14a at H0071793 (Districts 2, 3, and 4); PX 14a at J0000914 (District 4); PX 14a at L016920 (Districts 2 and 4); PX 14a at L0027041 (Districts 2, 3, and 4). But see Tr. 357-58 (reference to contract calling for price redetermination based upon prevailing prices in Districts 1, 2, and 4); PX 14a at H0121209 (Districts 1, 2, 3, and 4).

The court takes pain to note that we make no findings as to when price redetermination clauses in the Texas Gulf Coast/East Texas region began to routinely take account of either the Permian Basin or the entire State of Texas, as the case may be. For present purposes, it suffices to note that price redetermination clauses of such broad scope had not come into use in 1975.

64. Logically, where the taxpayer's gas is superior to the comparable gas on which the RMFP computation is based, the RMFP yields a conservative result in that it tends to *understate* the actual price

that the taxpayer would have obtained, had it sold its gas at the wellhead.

65. For federal income tax purposes, a "unitization" is defined generally as "an agreement under which two or more persons owning operating mineral interests agree to have the interests operated on a unified basis and further agree to share in production on a stipulated percentage or fractional basis regardless of from which interest or interests the oil or gas is produced." Treas. Reg. § 1.614-8(b)(6). Subject to certain exceptions not pertinent here, unitized natural gas properties must be treated as a single "property" for the purpose of making depletion computations. Treas. Reg. § 1.614-8(b)(1).

66. Tr. 87, 167-68 (Pohler admission). Mr. Martin conceded that Mr. Pohler addressed the Btu content of Exxon's casinghead gas in issue. Tr. 1970-72.

67. See generally DX 1 at 8-14 (Martin report); Tr. 1910-38, 1958-79. On cross-examination, Mr. Martin essentially conceded that his critique of Mr. Pohler's gas comparability study addresses only Btu content. Tr. 1959-60. Although Mr. Martin also opined that Mr. Pohler also failed to establish comparability with respect to three other factors, *i.e.*, volume of gas available for sale, delivery pressure, and deliverability (Tr. 1961), we find said opinion conclusory and unsubstantiated by the record, inasmuch as Mr. Martin's report and the remainder of his testimony completely failed to address the aforementioned three comparability factors.

68. The appellate proceedings in Exxon I, 88 F.3d at 968, have no bearing upon our inquiry, because Exxon did not appeal the trial court's gas comparability determination. Brief for Appellant *passim*, Exxon I (CAFC No. 95-5116), filed August 3, 1995.

69. Further, as explicated above, the relevant market area in 1974 consisted of Railroad Commission Districts 2, 3, 4, and 6, but *not* District 5. Exxon I, 33 Fed. Cl. at 259. Here at bar, however, it is stipulated that five of the 369 Exxon properties in issue were located in District 5, and it is likewise undeniable that a number of the Ellis gas wells in issue were located in District 5. PX 1 at SubX 22 (map showing locations of Exxon gas wells and Ellis gas wells); PX 19 at 8, 10, 11 (stipulation as to Exxon properties located in counties within District 5).

70. Tr. 87, 166-68; PX 1 at 32, 37.

71. Under the adverse inference rule, "when a party has relevant evidence within its control and fails to produce such [or to explain such failure], that failure raises the presumption that if in fact produced, it would be unfavorable to its cause." Day & Zimmerman Services v. United States, 38 Fed. Cl. 591, 602 n.13 (1997) (citing International Union (UAW) v. NLRB, 459 F.2d 1329 (D.C. Cir. 1972)). See also Barnett v. United States, 6 Cl. Ct. 631, 671 (1984) (citing, *inter alia*, Culbertson v. The Steamer Southern Belle, 59 U.S. (18 How.) 584, 588 (1855)).

72. PX 5 at SubX 9 *passim*. For example, Mr. Platt's study indicates that transaction G0221 involved a single well that began production in April of 1975. PX 5, SubX 9, at PL1-02674. Other examples of this sort abound. See e.g., id. at PL1-02678 (transaction G0230, single well, production began June 1975), PL1-02945 through PL1-02948 (four transactions, G0994 through G0997, each involving a single well that began production in 1975), PL1-03010 (transaction G1085, five wells, all of which began production in 1975), PL1-03217 (transaction L0017, four wells, all of which began production in 1975), PL1-03348 (transaction L0170, 31 wells, 24 of which began production in 1975). There is, of course, a simple explanation for this circumstance -- natural gas producers were energetically drilling new wells, spurred by the soaring gas prices of the mid-1970s.

73. So as to assure ourselves as to the reliability of Mr. Platt's well identification study, the court

examined a substantial number of the pipeline company contract files in evidence (PX 14a and PX 14b). The court was consistently able to locate specific references, in the correspondence and memoranda within those contract files, to the wells identified by Mr. Platt. Thus, as to the 1,810 transactions for which Mr. Platt was able to identify the related wells, we conclude that his well identification study is reasonably accurate.

74. Mr. Platt's well identification study furnishes the general location of the oil wells in question, *i.e*., the names of the pertinent field and the county, as well as the volume of casinghead gas produced by such oil wells in 1975. PX 5, SubX 9 *passim*. Given the availability of data regarding the volume of casinghead gas production in 1975, the computation of a deliverability rate (*i.e*., Mcf per day) seems eminently feasible. Moreover, the availability of data concerning the volume of casinghead gas production in 1975 suggests that such data is likewise available for subsequent years. For each of the gas wells in issue, as discussed below, Mr. Pohler estimated the size of the volume available for sale in 1975, *i.e*., the underlying gas reserves, by reference to the cumulative volume of gas that each gas well produced during the years 1975-1997. There is no apparent reason why he could not have employed a similar approach, in connection with oil wells, in order to estimate the volume of casinghead gas available for sale in 1975. Further, given the availability of the names of the fields and counties in which the oil wells in question were located, Mr. Pohler could have considered, in rough terms at least, the proximity of such oil wells to prospective buyers' pipelines. Therefore, relative to the casinghead gas in issue, it is evident that Mr. Pohler could have addressed not only Btu content, but three additional gas comparability factors -- volume available for sale, deliverability, and proximity to prospective buyers' pipelines. The gravity of Mr. Pohler's failure to address the aforesaid three factors, in relation to casinghead gas, is underscored by the uncontroverted testimony of Mr. Buie, based upon his personal experience as a gas buyer for Houston Pipe Line Company (HPL) in 1975, that in negotiating the price that HPL would pay for gas, the three most important factors were reserve size, deliverability, and the closeness of other competing pipelines. Tr. 315.

75. Tr. 49, 165-71; PX 1 at 7, 33-34.

76. PX 1 at 32, Appendix 6 (Pohler calculation of relative volumetric proportions of Exxon's 1975 casinghead gas and gas well gas production, based upon Railroad Commission data).

77. The Dwights database (PX 32) summarizes data from various filings that oil and gas producers are required to make with the Texas Railroad Commission, and is a recognized source of oil and gas well data commonly used in the oil and gas industry.

78. In contrast to the FTP, the "shut-in tubing pressure" is measured at the surface when the well is "shut in," meaning that the producer has closed the wellhead valves which regulate the gas flow. Reservoir or "rock pressure" is measured underground, in the reservoir itself. See, e.g., Exxon I, 33 Fed. Cl. at 256; Shamrock, 35 T.C. at 986. Over time, as the well produces gas and depletes the reservoir, all three of the aforementioned measures of pressure decrease.

79. Measurements of gas pressure are typically stated in terms of either gauge pressure or absolute pressure. Gauge pressure, reported as pounds per square inch gauge (psig), is the pressure indicated by a pressure gauge, representing the pressure above or below the atmospheric pressure. Absolute pressure, reported as pounds per square inch absolute (psia), equals gauge pressure plus the atmospheric pressure. For example, the average atmospheric pressure at sea level is 14.70 psia. All volume measurements of natural gas (*i.e*., cubic feet, Mcf, Bcf, etc.) are made in accordance with a standard pressure base, which presumes a standard temperature of 60 degrees Fahrenheit and a standard pressure. *Field Handling of Natural Gas*, *supra*, at 7, 9. Unless otherwise indicated, all volumes referenced herein are stated at the Texas standard of 14.65 psia, the standard pressure at which intrastate pipeline companies were required

to measure their gas in 1975, for purposes of their filings with the Texas Railroad Commission.

80. So defined, deliverability is somewhat related to reserve size and delivery pressure, since the deliverability of a high-pressure well situated atop a large reserve usually exceeds that of a low-pressure well situated atop a small reserve.

81. This is so, Mr. Buie explained, because a high rate of deliverability assists pipelines in filling their gas storage reservoirs in order to meet peak demands in winter and summer, when heating or air conditioning requirements drive up gas consumption. Stated differently, high deliverability connotes a greater ability to meet the buyer's immediate requirements on demand. Thus, in deciding whether to make the investment of laying a pipeline in order to connect to a well, pipeline companies look more favorably upon wells that are capable of producing gas at high rates of deliverability.

82. Tr. 222, 806, 1519, 2440-41, 2494-96.

83. Tr. 220, 806, 1520, 1527, 1548.

84. Tr. 1548. For purposes of computing the RMFP, a sale at the outlet of the separator is deemed the equivalent of a sale at the wellhead. Exxon I, 88 F.3d at 978; Panhandle, 187 Ct. Cl. at 150-51, 227, 236, 408 F.2d at 704.

85. Mr. Ellis at first denied that pipelines which transport gas from multiple wells to a central point are properly termed "gathering lines" (Tr. 1042), but later conceded that the term "gathering" might commonly be used to refer to such an arrangement. Tr. 1110. Similarly, Mr. Buie contended that a pipeline connecting one of several wells to a common delivery point is more typically called a "flow line" than a "gathering line." Tr. 476. In its entirety, however, the weight of the evidence militates against Mr. Buie's view, since the definition of "gathering line" the court adopts herein is consistent with the unequivocal views expressed by Messrs. Pohler, Eakin, and Platt, on Exxon's behalf, and Mr. Nicol, on the Government's behalf.

Mr. Platt, in particular, took great care to differentiate flow lines from gathering lines. Tr. 2566-67. In his view, a pipe running from the outlet of the separator to the custody transfer meter where the purchaser takes delivery of the gas is a gathering line, whereas a pipe running directly from the well to the custody meter, without separation, is a flow line. Tr. 2567. To further clarify his meaning, Mr. Platt made two drawings that illustrate the foregoing distinction. Tr. 2582-88; PX 52, 53. Importantly, Mr. Platt pointed out that while it is possible to have a flow line that runs from the well directly to the purchaser's custody meter, such an arrangement is uncommon. This is so, he explained, because a combination of a gas and a liquid in the same pipe cannot be accurately measured. Further, the Texas Railroad Commission requires separation prior to metering. Tr. 2567-68. See also PX 1 at 12 (Pohler report, to same effect).

86. See, e.g., PX 14a at D0001324-25 (correspondence pertinent to transaction G0472, describing how producer connected its multiple wells to a central point with a "gathering system").

87. Tr. 219, 323-24; PX 1 at 23.

88. PX 1 at SubX 2, 13; DX 2a.

89. Tr. 2596.

90. Tr. 1548. See, e.g., PX 14a at D0001159, D0001324-25 (contract pertinent to transaction G0472, granting the producer the option to either construct a gathering system from its wells to a central point, or

to require the pipeline company to construct said gathering system).

91. Tr. 1548, 2557-58, 2578, 2580-81, 2651-52.

92. Tr. 315, 345, 610-11; PX 2 at 7-8, 14, 16; PX 4 at 8.

93. Tr. 91; PX 1 at 41, SubX 22.

94. Tr. 93-98.

95. As of 1975, gas purchase contracts routinely contained dedication clauses, whereby the producer would dedicate all of its gas production from specified leases or acreage to the purchasing pipeline company for the term of the contract. Such gas purchase contracts generally recite a metes-and-bounds legal description of the dedicated property, and often include a map depicting the layout and boundaries of the dedicated property. Tr. 361-62. See, e.g., PX 14a at L016901 (dedication clause in contract relating to transaction L0226), L016937-39 (legal description and map of dedicated properties). Thus, relative to each Ellis transaction for which the pertinent gas purchase contract is available, Mr. Pohler evidently could have determined whether the gas in question came from a compact block of acreage or from scattered parcels of land, but neglected to do so.

96. In short, our visual scrutiny of the maps in question leads us to essentially the same answer as Mr. Pohler's "eyeballing" analysis. Had the Government presented any evidence tending to rebut Mr. Pohler's analysis, Exxon might not have been so fortunate.

97. This is not to say that Exxon's failure of proof in this regard has no consequences. On the contrary, as discussed below, the majority of the 2,058 Ellis transactions must be disqualified from consideration in the RMFP computation, due to Exxon's failure to present a systematic analysis of the size and configuration of the Ellis properties.

98. See also Exxon I, 33 Fed. Cl. at 257 (similar finding, relative to 1974).

99. One Btu (British thermal unit) is the amount of heat that is required to raise the temperature of one pound of water from 39 degrees Fahrenheit to 40 degrees Fahrenheit.

100. PX 1 at 33-34; *Field Handling of Natural Gas*, *supra*, at 5, reproduced at PX 1, SubX 9. For example, most of the raw gas processed through Exxon's Hawkins and East Texas plants in 1975 was casinghead gas. The raw gas processed in the Hawkins Plant was about 79% methane, 20% liquefiable hydrocarbons, and 1% contaminants, whereas the gas processed in the East Texas plant was only about 43% methane, but 56% liquefiable hydrocarbons. Contaminants made up the remaining 1% in each case. PX 1 at 33-34, SubX 24.

101. Similarly, asked whether, under Btu pricing, there was any premium paid for high-Btu gas in 1975, Mr. Buie emphatically replied: "Absolutely not." Tr. 319. See also Tr. 288-89; PX 1 at 21-22 (Pohler, to same effect). In response to the foregoing, defendant vehemently denies that Btu pricing eliminates price disparities between high-Btu and low-Btu gas. Defendant's Responses to Plaintiff's Proposed Findings of Fact, at 19, ¶ 50. Specifically, the Government points out that Exxon, upon processing its natural gas in order to extract the liquefiable hydrocarbons, thereafter sold the resultant refined products, *i.e*., natural gas liquids and residue gas, at prices that differed on a per-Btu basis. Id. (citing Tr. 2680-82). Defendant's argument is beside the point, however, because the RMFP is computed on the basis of comparable sales of *raw* gas, not *refined* products. Exxon I, 88 F.3d at 976. Consequently, the question is not, as the Government would have it, whether different types of *refined* products, *i.e*., natural gas liquids and

residue gas, commanded different per-MMBtu prices in 1975. Rather, the question is whether higher per-MMBtu prices were paid for high-Btu *raw* gas than for low-Btu *raw* gas. The Government has not shown this to be the case.

102. Pipeline company annual reports for the year 1975, filed with the FPC (in the case of interstate pipelines) and the Gas Utilities Division of the Texas Railroad Commission (in the case of intrastate pipelines), disclose the prices that such pipelines paid for gas in volumetric terms. PX 6 at 13 n.15; PX 10a-10k; PX 11a-11bb. Gas purchase transactions reported in such pipeline company annual reports are the starting point of the parties' respective RMFP computations, *i.e.*, the source from which each party has selected certain transactions that purportedly qualify as wellhead sales of comparable gas. The use of FPC annual reports (Forms 2) for this purpose has met with the approval of the Federal Circuit. Exxon I, 88 F.3d at 977. If the gas prices reported in the aforesaid pipeline company annual reports were stated on a per-MMBtu basis, it might be feasible, and even advisable, to use Btu pricing in the RMFP calculation. That is not the case, however, here at bar. Thus, on this record, we need not consider whether it would be preferable to compute the RMFP on the basis of Btu pricing, and we express no opinion as to the relevance of Btu content as a gas comparability factor if the RMFP were so computed.

103. A "correlation" is a statistical term describing the causal relationship between the numerical values of two or more variables, *e.g.*, specific gravity and Btu content. A *positive* correlation exists when there is a simultaneous increase or decrease in the value of two numerically valued random variables. *Webster's II New Riverside University Dictionary* 314 (1988). Conversely, a *negative* correlation exists when there is simultaneously an increase in the value of one numerically valued random variable and a decrease in the value of the other such variable. Id.

"Specific gravity" is a relative measure of the weight, or density, of a gas compared to ordinary air. DX 1 at 11. The density of a gas is typically expressed in terms of weight in pounds per cubic foot. For example, at a standard pressure and temperature of 14.7 psia and 60 degrees Fahrenheit, ordinary air has a density of 0.0763 lb/cf. Specific gravity may be expressed as a fraction in which the numerator is the density of the gas under consideration, and the denominator is the density of ordinary air, *i.e.*, "the ratio of a gas density to the density of air at the same conditions of temperature and pressure." *Field Handling of Natural Gas*, *supra*, at 10, reproduced at PX 1, SubX 9. Thus, the specific gravity of ordinary air equals 1.0.

104. Excerpts from two engineering treatises, appended to Mr. Pohler's report, confirm the existence of such a correlation. American Gas Association, Operating Section, *Fuel Gas Energy Metering -- Transmission Measurement Committee Report No. 5*, at 19-22; Donald L. Katz et al., *Handbook of Natural Gas Engineering* 161 (1959); reproduced at PX 1, SubX 28-29. Mr. Pohler developed his specific gravity/Btu correlation on the basis of gas composition data obtained from Exxon's "HIS Segment 66" database, which contains actual specific gravity and Btu measurements, made in 1980 or thereafter, for the gas produced by many of the Exxon wells in issue. Tr. 248; PX 1 at 37, Appendix 10. Noting the similarity between his correlation and the specific gravity/Btu correlations delineated in the aforesaid two engineering treatises, Mr. Pohler pointed out that his correlation should hold true not only for Exxon's gas, but also for any other gas sample under consideration, *i.e.*, the Ellis gas in issue. As Mr. Pohler stated, "those publications obviously did not use Exxon gas, and the laws of physics would just suggest that [said correlation] would apply to other gas samples as well." Tr. 229. In addition, as a cross-check on the validity of his approach, Mr. Pohler applied his correlation to the gas produced by the 1,140 Exxon gas wells in issue. Upon doing so, Mr. Pohler derived an average Btu value of 1.083 MMBtu/Mcf, which closely approximates the average Btu value of 1.080 MMBtu/Mcf that he computed on the basis of actual 1975 Btu data extracted from Exxon's business records. Tr. 103-04, 228-29; PX 1 at 37-39, SubX 27.

105. That Mr. Pohler qualified his opinion, couching it in terms of *volumetric* pricing (per Mcf), is consistent with the fact, noted above, that Btu pricing (price per MMBtu) had become commonplace in the natural gas industry by 1975. Under Btu pricing, high-Btu raw gas is no more valuable than low-Btu raw gas.

106. Tr. 1973-75. See *Fuel Gas Energy Metering -- Transmission Measurement Committee Report No. 5*, *supra*, at 19; *Handbook of Natural Gas Engineering*, *supra*, at 161; reproduced at PX 1, SubX 28-29. Mr. Martin conceded, further, that the aforesaid natural gas engineering treatises prescribe adjustments that can be made to correct the specific gravity/Btu correlation for the presence of non-hydrocarbon gases. Tr. 1974-75.

107. Tr. 1979.

108. This is so because the specific gravity and Btu data in Exxon's HIS Segment 66 database pertains to gas that was virtually free of non-hydrocarbon contaminants, *i.e*., nitrogen and carbon dioxide, whereas the specific gravity data in the Dwights GANL database relates to gas containing such contaminants. DX 1 at 12; Tr. 1926-27. Therefore, Mr. Pohler's specific gravity/Btu correlation is based upon contaminant-free gas (the HIS Segment 66 database), but the specific gravity values of the *Ellis* gas, to which Mr. Pohler applied his correlation, reflect the presence of such contaminants (the Dwights GANL database). What this means, as Mr. Pohler pointed out, is that his estimates of Btu value reflect the highest possible Btu content the Ellis gas could have, since his correlation assumes that the noncombustible contaminants in the Ellis gas were at the very low levels present in Exxon's gas. Accordingly, his correlation makes the Ellis gas appear to be of higher quality than it actually is. Tr. 139-40, 238-40; PX 1 at 40.

109. This principle cannot extend so far, however, as to absolve Exxon's failure of proof regarding the comparability of the casinghead gas in issue. As noted above, Mr. Pohler addressed Btu content in connection with the casinghead gas in issue, but completely disregarded the other five gas comparability factors, *supra*, insofar as casinghead gas was concerned. It is one thing to say that the taxpayer may rely upon *imperfect* evidence of comparability where better evidence is unavailable, but the proposition that the taxpayer can voluntarily *neglect* its burden of proving comparability, as with the casinghead gas in issue, is untenable.

110. Tr. 1958, 1962.

111. As noted above, the parties will attempt to stipulate as to the computation of Exxon's depletable "gross income from the property" (GIFP) for the taxable year 1975, relative to the 369 Exxon gas properties in issue. Pursuant thereto, the parties shall address the computational mechanics of excluding Exxon's casinghead gas from the GIFP.

112. *Field Handling of Natural Gas*, *supra*, at 36-51 (exhaustive discussion of field separation), reproduced at PX 1, SubX 9. See also Exxon I, 33 Fed. Cl. at 257 (similar findings, relative to 1974). Regarding the location of the field separator, Mr. Nicol explained that the producer ordinarily sets its separator on the "well pad." Tr. 1518, 2583-84 (Platt, to same effect). The well pad is a leveled area covered with crushed rock, or whatever other surfacing material is at hand, that is constructed to make an all-weather work surface on which to set the drilling rig and production equipment. Tr. 1513-14. A well pad is generally built in the shape of a square, ranging from 150 to 300 feet on a side, depending upon the size of the equipment required to drill the well. Tr. 1514-16. The producer normally, where feasible, sets its field separator at the edge of the pad or immediately adjacent to the pad. Tr. 1513, 1516. Economic considerations motivate the producer to do this, because locating the separator away from the existing well pad entails the costs of constructing a second "pad" and laying a longer pipeline to connect the wellhead and the separator. Tr. 1572-73. However, while the separator is generally situated on the well

pad, it also must be located at some distance from the wellhead, because otherwise it would interfere with the ingress of equipment used for periodic servicing and maintenance of the well. Tr. 1516-17. Thus, Mr. Nicol testified, a typical location for a field separator is anywhere between 50 and 500 feet from the wellhead proper. Tr. 1517-19.

113. That gas was, in fact, sold at the outlets of separators in 1975 was confirmed by Mr. Buie, who testified that some of Houston Pipe Line Company's gas purchase contracts specified such a delivery point. Tr. 367. See also Exxon I, 33 Fed. Cl. at 275 (similar finding, as to 1974).

114. Panhandle simply states, without elaboration or citation to precedent, that sales of gas at the "wellhead and separator," 187 Ct. Cl. at 151, 227, 233, 408 F.2d at 704, qualify for inclusion in the RMFP computation. See also 187 Ct. Cl. at 175, 408 F.2d at 718 (holding that "hydrocarbons obtained by passing a portion of the . . . [gas] production through a field separator" were eligible for percentage depletion, and observing: "That these hydrocarbon sales resulted in depletable income *should not be open to serious question*." (emphasis added)). Similarly, Exxon I merely cites Panhandle, again without further commentary or citation, as support for this proposition, 88 F.3d at 978.

115. By including sales "within a few feet of" the outlet of the separator, our definition acknowledges that the purchaser's gas custody meter -- the exact location of the point of delivery, where title to the gas passes -- is a device that is physically distinct from the separator, as opposed to physically coterminous with the separator. On this record, however, we decline to fix the meaning of "a few feet," in this context, since there is no industry standard that governs the precise location of the delivery point and custody meter. Rather, the placement of the custody meter is the result of ad hoc, on-site negotiations between representatives of the producer and the purchasing pipeline company.

116. See also 187 Ct. Cl. at 162, 408 F.2d at 710 ("The delivery point [in the qualifying sale] . . . was on the . . . lease near the wellhead."); 187 Ct. Cl. at 172, 408 F.2d at 717 ("near the wellhead on the lease property"); 187 Ct. Cl. at 175, 408 F.2d at 718 ("near the wellhead").

117. Although we are not bound by decisions of the Tax Court, and Panhandle does not expressly cite Shamrock as to the definition of a wellhead sale, we note that the Court of Claims consistently cited Shamrock with approval in the Hugoton and Panhandle decisions, in connection with various other aspects of the RMFP computation. See Hugoton I, 161 Ct. Cl. at 279, 315 F.2d at 871; Hugoton II, 172 Ct. Cl. at 459, 463-64, 349 F.2d at 427, 430; Panhandle, 187 Ct. Cl. at 161, 171, 174-75, 408 F.2d at 710, 715-16, 718.

118. That the field separator is located within the acreage covered by the producer's oil and gas lease is not open to question. Oil and gas leases typically grant limited surface rights, meaning that the producer has the right to use sufficient land on which to locate its well and the appurtenant equipment. Tr. 367. Thus, it stands to reason that producers invariably locate their equipment, including the field separator, within their leased acreage. A producer that located its separator on acreage *not* covered by its oil and gas lease would, no doubt, commit a common law trespass. As Mr. Buie put it, "most producers don't have the right of eminent domain." Id.

119. See PX 10a-10k; DX 14-35 (1975 Forms 2 received in evidence).

120. The "utility" referenced in Accounts 800 and 801 is the pipeline company that purchases the gas, and the "vendor" is the producer that sells the gas.

121. We are constrained to note that the empirical roots of the Panhandle presumption are murky, if not doubtful. None of the major natural gas RMFP cases -- Exxon I, Panhandle, the two Hugoton decisions,

or Shamrock -- decided over a period spanning almost 40 years, has made an explicit finding that interstate pipeline companies employed consistent, industry-wide standards in categorizing gas purchases under Accounts 800 and 801 in their FPC annual reports. Nor, even assuming that such industry-wide standards exist, have any of the foregoing precedents found that interstate pipeline companies routinely exercise due care in making these classifications, such that errors are relatively infrequent. Therefore, rather than being grounded in a prior empirical determination that such transactional classifications are intrinsically trustworthy, the stated justification for the Panhandle presumption invokes pragmatic concerns over the difficult character of RMFP cases. See Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704 ("It cannot be seriously disputed that it is impractical to go behind the [FPC] Forms 2 in a comprehensive manner because this would require an unduly time-consuming and burdensome examination of all purchase contracts listed in the gas purchase sections of the forms."), quoted with approval in Exxon I, 88 F.3d at 977. Although this court must, and will, pay due deference to the Panhandle presumption, we cannot help but observe the uneasy tension, if not outright conflict, between a court-made evidentiary rule that eases the taxpayer's burden of proof, on solely pragmatic grounds, and two venerable tenets of federal income tax law, enunciated by the Supreme Court, *i.e.*, the principle that income tax deductions, such as percentage depletion, are a matter of legislative grace and must be narrowly construed, INDOPCO, 503 U.S. at 84, and the maxim that the taxpayer has the burden of overcoming the presumptive correctness of the Commissioner's determinations, Welch v. Helvering, 290 U.S. at 115.

Assuredly, the Panhandle presumption is rebuttable by the actual terms of the contracts underlying the 978 interstate transactions in issue, here at bar, and many of the pertinent contract files are in evidence. PX 14a, 14b. Thus, we could conduct our own empirical test of the Panhandle presumption, by reviewing those hundreds of interstate contract files and making findings of fact concerning the overall accuracy of the transactional classifications in the FPC annual reports. Ironically, such an investigative foray would utterly frustrate the pragmatic considerations cited in Panhandle, insofar as this court would find itself mired in precisely the sort of "unduly time-consuming and burdensome" inquiry of which the Court of Claims warned. Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704.

122. It is undisputed that the distinction between NARUC Accounts 800 and 801 has nothing to do with whether the producer compresses or dehydrates the gas prior to sale. Tr. 930, 1741-43. The plain language of Accounts 800 and 801, 18 C.F.R. part 201, is addressed exclusively to *transportation* of the gas, *i.e.*, the identity of the party, producer, or purchaser, that transports the gas away from the wellhead. See Exxon I, 88 F.3d at 977. However, the classification of a transaction under Account 800 or Account 801 is probative of whether the producer processed its gas before sale, *i.e.*, for the extraction of liquefiable hydrocarbons, because interstate pipeline companies were required to report their purchases of processed gas under Account 802 ("natural gas gasoline plant outlet purchases"). 18 C.F.R. part 201, Account 802.

123. In addition, the Federal Circuit computed the 1974 RMFP on the basis of 24 transactions that Exxon's RMFP study indicated were free of transportation, compression, and dehydration prior to sale. Exxon I, 88 F.3d at 978-79. Thus, the "preferable" method of curing "tainted" transactions was neither a stated ground for the reversal of the decision below, nor a factor in the Federal Circuit's RMFP computation, but rather was an expression of the appellate panel's views as to the manner in which future RMFP cases should be litigated. As such, the Federal Circuit's remarks concerning the "preferable" method were plainly dicta, because "it is well established that a general expression in an opinion, which expression is not essential to the disposition of the case, does not control a judgment in a subsequent proceeding." Smith v. Orr, 855 F.2d 1544, 1550 (Fed. Cir. 1988). See also McDaniel v. Sanchez, 452 U.S. 130, 141 (1981); Kastigar v. United States, 406 U.S. 441, 455 & n.39 (1972). Of course, even if couched as dicta, the remarks of our superior court in Exxon I nevertheless command our most careful attention.

124. In the context of the following discussion, the sole focus of which is transportation of the gas, the court's references to "wellhead sales" should not be read to imply anything about processing, compression, or dehydration, each of which is separately addressed below.

125. Tr. 894-95. See also Tr. 959, 1032-34 (to same effect). Similarly, in support of Mr. Ellis' RMFP study, Messrs. Buie and Eakin used the on-the-lease criterion in order to identify purported wellhead gas purchases by Houston Pipe Line Company and Lo-Vaca Gathering Company, their respective employers in 1975, but did so without regard to the size of the pertinent leases. Tr. 365-67, 574-75, 658.

126. Tr. 508-10, 576-78, 585, 792, 799-802, 894, 1025-26, 1151-52. That a single gas producer commonly holds multiple leaseholds granted by different lessors is demonstrated by the gas purchase contracts in evidence (PX 14a and PX 14b), which generally include legal descriptions and/or maps of the leases dedicated to the contract. See, e.g., PX 14a at L016937-39 (legal descriptions and map of six leases, aggregating approximately 1,000 acres and involving six different lessors, dedicated to contract underlying transaction L0226).

127. Tr. 658, 762-63.

128. Tr. 791-92. Messrs. Buie and Ellis expressed the same point of view, and applied the on-the-lease criterion in like manner. Tr. 358, 576-78, 1009-10, 1040-41, 1103-15, 1202-04.

129. Mr. Ellis admitted that the on-the-lease criterion effectively disregards any cost of moving gas about within the confines of the lease, but sought to justify this omission by blandly opining that such on-the-lease transportation costs are immaterial. Tr. 1222.

130. Notwithstanding the length of the Government's averments in this regard, the court reproduces same in full, so as to make it clear that the Government, and not this court, is the sole and exclusive source of such contentions.

131. The parenthetical statement at the end of the foregoing quotation is the Government's statement, not any observation by this court.

132. Exxon, of course, vigorously disputes this grave accusation. See Plaintiff's Memorandum In Response To Defendant's Motion For Leave To Submit Appellate Briefs And Plaintiff's Exhibits Nos. 29 and 45 [from Exxon I], filed August 21, 1998, at 4-5.

133. This distinction is not novel to the proceedings at bar, inasmuch as the court noted it at an early stage of the trial. Tr. 957. Moreover, throughout the course of the trial and thereafter, in their various post-trial submissions, the parties have exhaustively ventilated their respective views as to the legal significance of this distinction.

134. Assuredly, Mr. Ellis testified that he reclassified two *de jure* Account 800 transactions as non-wellhead sales, for purposes of his RMFP study. Tr. 1002-03. However, he was unable to recall which two transactions he had reclassified. Tr. 1027-29. On this record, it cannot be said that Exxon rebutted the Panhandle presumption with respect to those two unidentified transactions.

135. Mr. Ellis admitted to making 37 such reclassifications (Tr. 932, 1001-02), but upon retiring to review the record, the court found 46 transactions listed under Account 800 in Mr. Ellis' RMFP study that had, in fact, been reported to the FPC under Account 801.

136. Tr. 1002, 1084-85, 1106, 1115, 1121-22, 1134-36, 1141-43.

137. At trial, it was clear that Mr. Ellis relied solely upon the on-the-lease criterion, since he was unable to cite any alternative factual basis for making these 46 reclassifications. Tr. 1004-07, 1081-82, 1103-06. Further, in one of its post-trial submissions, Exxon conceded that Mr. Ellis had no rational explanation as to why the interstate pipeline companies in question allegedly "misclassified" 46 transactions under Account 801, except for their purported failure to satisfy Exxon's on-the-lease criterion. Joint Motion To Clarify, filed February 3, 1999, at 2.

138. Similarly, Mr. Eakin identified Lo-Vaca's *de facto* Account 801 gas purchases by reference to Lo-Vaca's Account 42, which purports to be modeled after NARUC Account 801 (field line purchases). According to Mr. Eakin, Lo-Vaca Account 42 represents transactions with off-the-lease delivery points. Tr. 637-40, 643, 658-60, 735; PX 4 at 3, 16.

139. Specifically, Mr. Ellis' report lists transactions G3961, G3905, G3957, G3914, G3911, G3954, G3912, and G3916 under "Account 800 -- Intrastate" (PX 6, SubX G, at 6), but Lone Star's 1975 GUD report classified these transactions under Account 801. PX 11o, E18686-87.

140. Extending the Panhandle presumption to the *de facto* Account 800 transactions would, in effect, cloak the expert opinions of Messrs. Ellis, Buie, and Eakin with a rebuttable presumption of correctness, a result that would totally eviscerate the well-settled maxim that expert opinion testimony, even if uncontradicted, is not conclusive and binding upon the trier of fact. Dayton Power & Light, 292 U.S. at 299; Sartor, 321 U.S. at 627-29; Sternberger, 185 Cl. Ct. at 535-36, 401 F.2d at 1016; Mims, 375 F.2d at 140 & n.2.

141. This figure reflects Mr. Ellis' withdrawal of one transaction (number G1062) at trial. Tr. 890-91; PX 6, SubX G, at 19.

142. The court made this determination by tracing these 158 transactions to the tabulation of *de jure* Account 800 transactions in Mr. Robles' RMFP study. DX 5, SubX 1B. A listing of these 158 *de jure* Account 800 transactions is presented in Appendix A, *infra*.

143. DX 5, SubX 2A (listing transactions G0695, G0712, G0713, G0763, G1037, G1038, G1075, G1076, G1077, G3095, and G3103, as "intrastate wellhead sales"). Although Mr. Robles, for the Government, concluded that transaction G3095 was a wellhead sale, Mr. Ellis' RMFP study classified transaction G3095 as a *de facto* Account 801 transaction, *i.e.*, a sale involving an off-the-lease point of delivery. PX 6, SubX G, at 31. However, the pertinent gas purchase contract, dated February 24, 1973, provides that the points of delivery thereunder were to be "*at the wellhead* of each of Seller's wells." PX 14b at J0006588 (emphasis added). Inasmuch as Mr. Ellis' report cites, and we have found, no evidence contradicting the foregoing contract language, the court agrees with Mr. Robles' determination.

144. Tr. 2657. We reject Exxon's attempt to inflate the Government's stipulation, so as to make it embrace every transaction in issue. Plaintiff's Response To Defendant's Proposed Findings Of Fact, filed May 18, 1998, at ¶ 65; Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 6 n.1. Counsel for the United States expressly limited his stipulation to "this transaction," meaning transaction G0472. Tr. 2657.

145. The other 1,409 contested transactions consist of the 774 *de jure* (interstate) and the 635 *de facto* (intrastate) Account 801 transactions listed in Mr. Ellis' report. Exxon's collateral estoppel argument does not touch upon these 1,409 transactions, which indisputably fail to qualify as wellhead sales. Rather, the parties' dispute over these 1,409 transactions centers upon the propriety of their inclusion in the RMFP computation, after deducting transportation costs, under the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78.

146. It is unmistakably Exxon's position, repeatedly expressed throughout the course of these proceedings, that an on-the-lease transaction is the alleged factual equivalent of a *de jure* Account 800 transaction. For example, the accuracy of the court's characterization of Exxon's collateral estoppel argument is well demonstrated by Exxon's response to the court's order dated June 23, 1998. Therein, we put four questions to the parties, the last of which inquired as follows:

4. Assuming that the classification of a gas purchase transaction in compliance with the standards prescribed in NARUC Accounts 800 and 801, 18 C.F.R. part 201, conflicts with [Exxon's] on-the-lease criterion for *de facto* Account 800 classification, which standard controls as a matter of law, and for what reason or reasons?

Order of June 23, 1998, at 3. However, Exxon declined to squarely address the court's query on the basis of the assumption stated therein. Instead, firmly denying even the hypothetical existence of a conflict between its on-the-lease criterion and the *de jure* Account 800 standard, Exxon reiterated its contention that the two standards are one and the same, as follows:

[W]e believe the evidence is inconsistent with the assumption in question 4 that sales were classified under FPC Account 800 using a delivery point standard different from the lease boundary. The Panhandle opinion, the way that pipelines actually classified their purchases on the [FPC] Forms 2 and on later GUD filings made after the State [of Texas] adopted the NARUC classifications, and statements made by FERC all indicate that delivery on the lease was understood to be the factor distinguishing between FPC Accounts 800 and 801.

Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 6 n.1.

147. It appears that Exxon has misinterpreted statements made by the Court of Federal Claims, in Exxon I, as formal judicial findings of fact.

148. Moreover, as noted above, Exxon contends that an on-the-lease sale is a wellhead sale because the "lease" corresponds with the "premises" referenced in Treas. Reg. § 1.613-3(a), which requires the use of the RMFP method if "the gas is not sold on *the premises*, but instead is "transported from *the premises* prior to sale" (emphasis added). However, Exxon's position finds no explicit support in the Federal Circuit's Exxon I opinion, which nowhere mentions the term "premises" in conjunction with the definition of a wellhead sale.

149. Exxon I, 88 F.3d at 977 (quoting 33 Fed. Cl. at 273 (emphasis added and in original)).

150. PPF at ¶ 64 (emphasis added) (citing PX 6 at 16-17; Tr. 927-30 (Ellis)).

151. Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 3; Plaintiff's Memorandum In Response To Defendant's Motion For Leave To Submit Appellate Briefs And Plaintiff's Exhibits Nos. 29 And 45 [from Exxon I], filed August 21, 1998, at 4-5. As noted herein, *supra*, by order dated September 29, 1998, we agreed to take limited judicial notice of said briefs, for the purpose of determining the scope of the issues that were actually litigated before the Federal Circuit in Exxon I. The propriety of consulting such extrinsic evidence in order to determine the preclusive effect of a prior judgment, when it is uncertain from the opinion memorializing that judgment whether the prior court considered and decided a particular issue, is well settled. Russell, 94 U.S. at 608.

152. See also id. at 48-49 (to same effect).

153. Brief For Appellant at 48-50, Exxon I (CAFC No. 95-5116). See also Brief For Appellant at 11, Exxon I (CAFC No. 95-5116) ("*The court* [below] *ruled* that an RMFP study should exclude sales classified for regulatory purposes as 'natural gas field line purchases' because they involve transportation away from *the producing property* prior to sale." (emphasis added) (citing Exxon I, 33 Fed. Cl. at 272-74)); id. at 41-42 ("[T]*he lower court* . . . *rule*[d] that only sales occurring *on the lease* and before dehydration could qualify as wellhead sales." (emphasis added) (citing Exxon I, 33 Fed. Cl. at 273-74, 275-77)); id. at 44 ("If, *as the court below held*, wellhead sales are restricted to sales that occur *on the lease* . . . ." (emphasis added)); id. at 45 ("*The court below held* that the RMFP study should exclude . . . sales where the delivery point, though in the producing field, was *off the producing lease* (Account 801 sales)." (emphasis added) (citing Exxon I, 33 Fed. Cl. at 273-74)). As noted above, Exxon's contention that its on-the-lease criterion was adopted by the Court of Federal Claims in Exxon I is utterly without merit.

154. Exxon's reply brief foregoes any mention of the term "lease" in conjunction with the definition of a wellhead sale. Reply Brief For Appellant at 18-25, Exxon I (CAFC No. 95-5116).

155. Brief For Appellee *passim*, Exxon I (CACF No. 95-5116). What the Government argued, rather, was that the Court of Federal Claims had correctly defined a wellhead sale in accordance with the FPC definition set out in 18 C.F.R. part 201, Account 800, *i.e.*, a transaction in which the purchaser transports the gas away from the wellhead. Id. at 35, 37-38, 41. As noted above, the Federal Circuit agreed. Exxon I, 88 F.3d at 977.

156. Even without Exxon's judicial admissions, *supra*, there is *substantial* uncertainty, on this record, as to whether the validity of Exxon's on-the-lease criterion was actually litigated before, and decided by, the Federal Circuit in Exxon I. Collateral estoppel is inapplicable "if upon the face of a record any thing is left to conjecture as to what was necessarily involved and decided" in the prior action. Russell, 94 U.S. at 610. See also id. at 608; Irving Nat. Bank v. Law, 10 F.2d 721, 724-25 (2d Cir. 1926) (L. Hand, J.) (noting that the preclusive effect of a prior judgment does not turn upon "imported ingenuities of which the judges were unconscious").

157. Pl. Brf. at 26-27; Pl. Reply at 9; Plaintiff's Memorandum In Response To Defendant's Motion For Leave To Submit Appellate Briefs And Plaintiff's Exhibits Nos. 29 And 45 [from Exxon I], filed August 21, 1998, at 3.

158. Def. Reply at 18 (reproduced in pertinent part, *supra*).

159. Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 4 ("Arkansas Louisiana Gas Co. is the *only* interstate gas pipeline company required to file an FPC Form 2 in 1974 that is listed at 88 F.3d at 979 n.9." (emphasis added)).

160. Defendant's Response To Plaintiff's Report Of Their Collateral Estoppel Contentions, filed January 9, 1998, at 8 (reproduced in pertinent part, *supra*).

161. Specifically, Exxon acknowledges that an on-the-lease sale may involve transportation of the gas away from the wellhead by the producer. Plaintiff's Response To Defendant's Proposed Findings Of Fact (PRDPF), filed May 18, 1998, at 32-37, ¶¶ 65-66; Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 6 n.1. However, as noted above, Exxon maintains that such on-the-lease transportation adds no material value to natural gas. PRDPF at 32-37, ¶¶ 65-66; Tr. 1222, 2476, 2481-82. Whether on-the-lease transportation, prior to sale, adds material value to natural gas is an issue that was most certainly *not* litigated and decided in Exxon I, given that Exxon's 1974 RMFP study failed to address, in any respect, the value added by transportation. Exxon I, 88 F.3d at 977, 33 Fed.

Cl. at 275.

162. In concluding that the 24 "Account 800 sales" qualified for inclusion in the RMFP computation, the Federal Circuit also relied upon the categorization of those 24 transactions in Mr. Ellis' 1974 RMFP study as sales of uncompressed, undehydrated gas. Id. at 978-79.

163. Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 4 (reproduced in pertinent part, *supra*).

164. See also Icicle Seafoods, Inc. v. Worthington, 475 U.S. 709, 714 (1986) (holding that when a federal court of appeals believes that the trial judge, sitting as finder of fact, has failed to make essential findings of fact, the appellate court "should not simply . . . ma[k]e factual findings on its own"); First Interstate Bank of Billings v. United States, 61 F.3d 876, 882 (Fed. Cir. 1995) ("It would be a distortion of our role to draw conclusions about the facts, . . . rather than having the trial court make its own findings in light of the [legal] standard that we have endorsed.") (citing Icicle, *supra*).

165. Further, as noted above, the Exxon I opinion does not even mention the word "lease." We read the total absence of the word "lease" from the Exxon I opinion as compelling evidence that the Federal Circuit did not consider the distinction between on-the-lease sales and off-the-lease sales to be essential to its decision. See Schendel, 83 F.3d at 1406 (resolution of factual issue deemed irrelevant to prior judgment where prior opinion made no reference to such issue).

166. In short, the 24 transactions at issue in Exxon I were either disputed or undisputed. But Exxon cannot manipulate the doctrine of collateral estoppel so as to have it both ways. If Exxon now wishes to argue that the qualification of those 24 transactions was an issue actually in dispute, the resolution of which was essential to the judgment on appeal in Exxon I, then the question arises whether it owes a candid explanation to the Federal Circuit of how the Exxon I panel came to view said transactions as "undisputed." Exxon I, 88 F.3d at 979.

Moreover, for the sake of completeness, we note Exxon's lesser contention that the inclusion of the aforementioned 24 transactions in the 1974 RMFP computation, in Exxon I, precludes the Government from litigating the qualification of those 24 specific transactions for inclusion in the 1975 RMFP computation, here at bar. Plaintiff's Memorandum In Response To The Court's Wellhead Sale Questions, filed July 10, 1998, at 3. However, Exxon has never disclosed which of the 2,058 transactions in Mr. Ellis' 1975 RMFP study, if any, correspond to the 24 transactions at issue in Exxon I. Although one of the Government's exhibits (DX 5A) purports to show that 19 of the 24 transactions included in the 1974 RMFP computation, Exxon I, 88 F.3d at 979 n.9, are also in issue here, relative to 1975, neither party has cited, and we have not found, anything in the record that confirms that the 19 transactions listed in said exhibit do, in fact, correspond to their alleged 1974 counterparts.

167. Even so, the parties' controversy over the definition of a wellhead sale relates solely to the computation of the RMFP under Treas. Reg. § 1.613-3(a), a subject on which the Code itself is silent. In 1975, as in 1974, as we have observed elsewhere, "the Code and pertinent Treasury Regulations unambiguously direct[ed] an integrated natural gas producer to Treas. Reg. § 1.613-3(a) for guidance as to the manner in which its percentage depletion allowance must be computed." Exxon, 40 Fed. Cl. at 83. Further, upon the enactment of § 613A in 1975, Treas. Reg. § 1.613-3(a) was retained unamended in the Code of Federal Regulations. Id. at 89. Thus, we are doubtful that a change in the controlling law occurred between 1974 and 1975, as the Government urges, that would bar the application of collateral estoppel.

168. See also Commissioner v. Soliman, 506 U.S. 168, 174 (1993); Malat v. Riddell, 383 U.S. 569, 571

(1966) (per curiam); Hanover Bank v. Commissioner, 369 U.S. 672, 687 (1962); Commissioner v. Korell, 339 U.S. 619, 627-28 (1950); Old Colony Railroad Co. v. Commissioner, 284 U.S. 552, 560 (1932); Costain Coal, Inc. v. United States, 126 F.3d 1437, 1441 (Fed. Cir. 1997). In an early case involving the interpretation of the statutory depletion allowance, the Supreme Court observed that "the plain, obvious and rational meaning of a statute is always to be preferred to any curious, narrow, hidden sense that nothing but the exigency of a hard case and the ingenuity and study of an acute and powerful intellect would discover." Lynch v. Alworth-Stephens Co., 267 U. S. 364, 370 (1925). Much the same criticism, we think, can be directed at Exxon's effort to read the term "lease" into Treas. Reg. § 1.613-3(a).

169. See also *Roget's II -- The New Thesaurus* 515 (1988) ("not far from another in space

. . . or relation"); Barbara Ann Kipfer, *Roget's 21st Century Thesaurus* 448 (1992) ("adjacent, close, contiguous, . . . near-at-hand, nearby, nearest"); William C. Burton, *Legal Thesaurus* 259 (1980) ("abutting, adjacent, adjoining, at hand, . . . close, close at hand, conjoining, . . . contiguous, handy, juxtapositional, near, near by . . . next to").

170. Our reading of the regulatory phrase, "in the immediate vicinity of the well," is fully in accord with longstanding natural gas RMFP precedents, in which the courts have consistently construed and applied the RMFP method, under Treas. Reg. § 1.613-3(a) and its predecessors, with the ultimate end of ensuring that the integrated producer's percentage depletion allowance is based upon nothing more than the value of the natural gas "at the mouth of the well." Greensboro, 79 F.2d at 701, cited with approval in Hugoton II, 172 Ct. Cl. at 455-56 n.18, 349 F.2d at 425 n.18; Panhandle, 187 Ct. Cl. at 144, 169, 408 F.2d at 700, 715. Moreover, our restrictive interpretation of Treas. Reg. § 1.613-3(a) properly acknowledges that the allowance for percentage depletion, as with any income tax deduction, is a matter of legislative grace, and must be narrowly construed. See, e.g., INDOPCO, 503 U.S. at 84; Southwest Exploration, 350 U.S. at 312; Bankline Oil, 303 U.S. at 366.

171. In a later section of this opinion, we consider the evidentiary basis for Exxon's contention that on-the-lease transportation adds no value to natural gas.

172. Literally, "it is known from its associates." *Black's Law Dictionary* 1060 (6th ed. 1990).

173. Panhandle also involved a separate controversy over the RMFP computation for the taxpayer's gas production in the Hugoton Embayment, located in southwestern Kansas, western Oklahoma, and the north Texas Panhandle. Id. at 143-60, 408 F.2d at 699-709.

174. Certain circumstances, not pertinent to the immediate discussion, frustrated the Court of Claims' efforts to compute an RMFP on the basis of the taxpayer's single wellhead sale. See generally Panhandle, 187 Ct. Cl. at 168-75, 408 F.2d at 714-18. However, that does not diminish the Panhandle court's express finding that the aforesaid sale was, in fact, a wellhead sale.

175. In Panhandle, relative to the Hugoton Embayment RMFP computation, both the taxpayer and the Government relied generally upon comparable gas purchases made by the interstate pipeline companies operating in the Hugoton Embayment (including the taxpayer), as reported "in the gas purchase section of the Forms 2 on file with the FPC." Panhandle, 187 Ct. Cl. at 151, 408 F.2d at 704. See also 187 Ct. Cl. at 227 (findings as to RMFP sampling methodology). The Court of Claims approved the parties' reliance upon the transactions reported in the FPC annual reports, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05, thus giving rise to the Panhandle presumption. See Exxon I, 88 F.3d at 977 (construing Panhandle "as creating a rebuttable presumption that filed [FPC] annual reports constitute prima facie proof of the transactions they represent").

176. We attach no talismanic quality to the mere fact that the conjunctive formulation of Panhandle's wellhead sale definition (*i.e*., on-the-lease *and* near the wellhead) outnumbers the similar, but disjunctive, phrasing that Exxon prefers (*i.e*., on-the-lease *or* near the wellhead) by the margin of six to two in the Panhandle opinion. But neither is this court willing to dismiss the Panhandle opinion's description of a qualifying wellhead sale as a sale "on the lease" *and* "near the wellhead" -- not once, but six times -- as a mere coincidence or accident.

177. Needless to say, this further undermines Exxon's contention, *supra*, that the Federal Circuit adopted the on-the-lease criterion in Exxon I. Therein, the Federal Circuit also stated:

In Panhandle, the taxpayer entered into a contract . . . to sell gas from fourteen wells at a price of $0.325/Mcf. . . . The delivery point for part of the production from one well, the McPherson No. 1-35 well, was *near the wellhead*. The balance of the production was transported *from the wellhead* for delivery to [the purchaser] at locations from thirty to forty miles away.

Exxon I, 88 F.3d at 974 (emphasis added). As to the single wellhead sale in the Howell Field, *i.e*., the sale "near the wellhead" of the McPherson No. 1-35 well, at issue in Panhandle, the Federal Circuit apparently deemed it irrelevant that such delivery point also happened to be on the McPherson lease. Moreover, relative to the non-wellhead sales in the Howell Field, the Federal Circuit described the disqualifying circumstance as the producer's transportation of the gas away "from the wellhead," not the transportation of the gas away from the pertinent leases.

178. See also id. at 173, 408 F.2d at 717 ("off the *leases*" (emphasis added)); id. at 242, 245 ("off the *leases*" (emphasis added)).

179. See also id. at 173, 408 F.2d at 717 (noting the "3 ½¢ per MCF stipulated cost to plaintiff of *gathering* and transporting its gas *away from the wellheads* before sale" (emphasis added)).

180. Cf. Panhandle, 187 Ct. Cl. at 169, 408 F.2d at 715 ("The taxpayer in Greensboro produced and sold gas from its own wells, but after transportation from the *individual* leases." (emphasis added) (construing Greensboro, 30 B.T.A. 1362, 1364, aff'd, 79 F.2d 701)).

181. Pl. Reply 9 n.1. We disregard, as totally irrelevant to our conclusions herein, Exxon's citation of IRS Private Letter Ruling 8246023 (Aug. 6, 1982), inasmuch as Congress has expressly directed that such private rulings "may not be used or cited as precedent." § 6110(j)(3). Exxon also cites a secondary authority, Frederic J. Attermeier, *The Crude Oil Windfall Profit Tax of 1980: How It Will Affect Oil Companies*, 52 Journal of Taxation 258, 261 (May 1980), for the proposition that the 1980s-era windfall profit tax on crude oil production employed an on-the-lease criterion. However, even assuming that such commentary is entitled to any weight, the court is hard put to discover any meaningful connection between the computation of an integrated natural gas producer's 1975 federal income tax deduction for percentage depletion and an excise tax on crude oil production enacted five years thereafter.

182. Were Exxon to establish, by affirmative probative evidence, that interstate pipeline companies did, in fact, categorize their 1975 gas purchases under Accounts 800 and 801 in accordance with an on-the-lease/off-the-lease distinction, that would *not* conclusively establish that on-the-lease transactions are eligible for inclusion in the RMFP computation. Industry practices cannot override the requirement that the RMFP computation be limited to sales "in the immediate vicinity of the well." Treas. Reg. § 1.613-3(a). At most, such a showing would require us to consider whether extending the *rebuttable* Panhandle presumption, *supra*, to such on-the-lease transactions would produce a result that is consistent with Treas. Reg. § 1.613-3(a).

183. Tr. 1023-24, 1036-39. Mr. Ellis also admitted that he is unaware of the origins or purpose of the FPC definitions of Accounts 800 and 801, promulgated in 18 C.F.R. part 201, and that his own definition of a "wellhead sale" -- a sale anywhere "on the lease" -- is inconsistent with the plain language of the FPC's Account 800 definition. Tr. 1020-23, 1046-49.

184. Tr. 1002, 1084-85, 1106, 1115, 1121-22, 1134-36, 1141-43.

185. In fact, by opining that an on-the-lease delivery point is the "common element" of *de jure* Account 800 transactions, Mr. Ellis told the court nothing about the reporting practices of interstate pipeline companies that we could not deduce by means of simple logic. As noted above, barring error on the part of the reporting pipeline company, every *de jure* Account 800 transaction is a gas purchase "on the lease," inasmuch as the purchaser, not the producer, transports the gas away from the wellhead. Exxon I, 88 F.3d at 977. From that truism, however, it does not automatically follow that interstate pipeline companies routinely and systematically reported every gas purchase made somewhere on the producer's leased acreage, whether in the immediate vicinity of the pertinent well(s) or not, under Account 800 in their FPC filings.

186. Tr. 847.

187. In addition, Mr. Eakin testified that Lo-Vaca Gathering Company, his employer in 1975 and one of the major intrastate pipeline companies in issue, was already using an on-the-lease/off-the-lease distinction in 1975, in order to differentiate gas purchases at the wellhead from non-wellhead gas purchases. Tr. 659-61, 735-36, 752. However, Mr. Eakin admitted that the word "lease" is not mentioned in the written internal accounting policy that governed the categorization of Lo-Vaca's wellhead and non-wellhead purchases in 1975. Tr. 659-61, 736; PX 4, SubX A, at 1. Because Exxon presented no other evidence tending to support Mr. Eakin's assertion, the court discounts his uncorroborated and self-serving testimony.

188. Before and during trial, as noted above, the court repeatedly instructed the parties to have their expert witnesses cross-reference their written reports to the underlying documentary evidence on which their opinions rest. Order filed December 2, 1997; Transcript of Pre-Trial Conference, held December 18, 1997, at 11-12, 23-24; Trial Transcript at 975-78, 2772. Notwithstanding the court's directive, Exxon failed to furnish workpapers that cross-referenced the 1,080 intrastate transactions in Mr. Ellis' 1975 RMFP study (PX 6) to the 1977-1979 GUD reports in evidence, which consist of 24 rolls of microfilm. PX 26, Tr. 941-42. Lacking such, we decline to sift through those 24 rolls of microfilm, in order to ascertain whether the 1,080 intrastate transactions in issue are truly represented therein.

189. We do not consult the FPC regulations because those provisions conclusively establish, as a matter of law, whether a transaction qualifies for inclusion in the RMFP computation. Rather, we view the text of the regulatory definitions of Accounts 800 and 801, and the manner in which the FPC applied such rules in practice, as probative evidence of industry practices in 1975, *i.e.*, whether the natural gas industry utilized an on-the-lease/off-the-lease distinction in 1975, as Exxon claims, in order to differentiate Account 800 transactions from Account 801 transactions.

190. See *Natural Gas Policy Act of 1978: Interim Regulations*, 43 Fed. Reg. 56448, 56576 (Dec. 1, 1978), codified at 18 C.F.R. § 271.1105(c)(2) (1979) (interim regulation limiting allowance to off-the-lease gathering); Order No. 94, *Order Amending Interim Regulations Under the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act*, 45 Fed. Reg. 53099, 53104, 53107-08 (July 25, 1980) (amending interim regulation to extend allowance to on-the-lease gathering); Order No. 94-A, *Regulations Implementing Section 110 of the Natural Gas Policy Act of 1978 and Establishing Policy Under the Natural Gas Act*, 48 Fed. Reg. 5152, 5156 (Jan. 24, 1983) (explaining policy change

implemented by Order No. 94, *supra*).

191. See also Panhandle, 187 Ct. Cl. at 175, 408 F.2d at 718 ("In the Hugoton case, the court's rejection of the use of such [royalty] prices was more by implication."); Hugoton I, 161 Ct. Cl. at 279 n.12, 315 F.2d at 870 n.12. There are at least two sound reasons for not basing percentage depletion determinations upon state royalty law principles. First, state royalty law and the federal income tax law of percentage depletion obviously serve different objectives and, thus, produce different measures of the wellhead value of natural gas. See, e.g., Owen L. Anderson, *Royalty Valuation: Should Royalty Obligations Be Determined Intrinsically, Theoretically, Or Realistically?*, 37 Nat. Resources J. 547, 564 (1997) (noting that from the standpoint of estimating the market value of natural gas at the wellhead, the definition of a comparable wellhead sale for state-law royalty valuation purposes differs from the definition of a comparable wellhead sale for purposes of the RMFP method of computing percentage depletion).

Second, the definition of the price or value on which natural gas royalties are payable varies significantly from state to state. See, e.g., Anderson, *supra* at 549-52; Allen K. Harris, Jr., *Gas Royalties -- Leading State and Federal Cases Reviewed: Alice's Adventures in "Royalty-Land," 3*7 Ok. L. Rev. 699, 699 (1984) ("The ordinary royalty clause pertaining to gas is one of the most ambiguous and incomplete provisions of an oil and gas lease ever to be brought before the courts."). Thus, if state royalty law governed percentage depletion computations, it would be virtually impossible to ensure the uniform application of the percentage depletion provisions of the Internal Revenue Code to similarly situated gas producers located in different states.

192. Plaintiff's Memorandum In Response To Defendant's Motion For Leave To Submit Appellate Briefs And Plaintiff's Exhibits Nos. 29 And 45 [from Exxon I], filed August 21, 1998, at 4 (emphasis added).

193. Tr. 2476, 2481-82; PX 1 at 5.

194. Tr. 2429, 2479.

195. See, e.g., PX 14b at L00116000, L00116027 (contract pertinent to transaction L0170, providing that purchaser would take delivery of gas at producer's separators, but limiting purchaser's obligation to construct gathering lines to such delivery points to one mile of gathering line per each billion cubic feet (Bcf) of natural gas reserves available for purchase); PX 14b at H0119000 (contract pertinent to transactions G1075, G1076, and G1077, providing for delivery at wellheads, but limiting purchaser's obligation to one mile of gathering line per five Bcf of reserves).

196. For example, transaction L0170 involved Lo-Vaca Gathering Company's 1975 purchases of gas produced by Gulf Oil Corp. from 31 wells situated upon over 40,000 leased acres in Webb County, Texas. Tr. 783-84; PX 5, SubX 9, at PL1-03348. To put the size of Gulf's Webb County leases in perspective, we note that 40,000 acres equals 62.5 square miles, which very closely approximates the size of the District of Columbia. See *Rand McNally Road Atlas* 104 (1993) (63 square miles in District of Columbia). Based upon the contract, other corroborating documentation in the pertinent Lo-Vaca contract file, and Mr. Eakin's testimony, the court finds that Lo-Vaca constructed an extensive gathering system in order to connect the 31 Gulf wells to its pipeline system, laying gathering lines in order to take delivery of the gas at each such well, or the separator appurtenant thereto. PX 14b at L00116027; Tr. 783-84. That Lo-Vaca did, in fact, construct an extensive gathering system in order to take delivery of this gas at each of Gulf's wells is established by numerous memoranda in the contract file that document Lo-Vaca's construction of the necessary gathering lines, e.g., PX 14b at L00115386, L00115396, L00115399, L00115400, L00115403, L00115407, L00115411, L00115413, L00115423, L00115425, L00115426. Further, all 31 of the delivery points were on the "lease," as Exxon defines that term, meaning that all of the gas produced by Gulf's 31 wells was delivered within the 40,000-plus acres held by Gulf under its

various oil and gas leases. Thus, given the sheer size of the leased acreage relating to the Lo-Vaca/Gulf contract, it is evident that Lo-Vaca had to perform substantial gathering "on the lease."

197. Tr. 2563. A systematic comparison of Mr. Platt's well identification workpapers (PX 5, SubX 9) and Mr. Ellis' RMFP workpapers (PX 6, SubX G) discloses that the volume of gas associated with single-well transactions constitutes only about 12% of the total volume of gas associated with the 1,809 Ellis transactions with identified wells. In contrast, roughly 60% of such gas, in terms of volume, relates to transactions involving at least five wells.

198. For example, in transaction L0170, *supra*, Lo-Vaca limited its obligation to construct a gathering system to take delivery of Gulf's gas at the wellheads, *i.e.*, to one mile of gathering line per one Bcf of available reserves. PX 14b at L00116000, L00116027. Conversely, if Lo-Vaca had assumed an *unconditional* obligation to lay a gathering line to each Gulf well, Lo-Vaca also would have assumed the risk of laying gathering lines to any wells lacking sufficient reserves to justify the investment in such gathering lines. Elementary logic compels the conclusion that Lo-Vaca would compensate for that risk by bidding a somewhat lesser price for Gulf's gas.

199. ERDPF at 37; Tr. 1211 (Ellis).

200. Tr. 1214. Mr. Ellis' explanation reflects the commonplace definition of a "median," which is a statistical measure of central tendency, representing the middle value in a distribution of numerical values arranged in ascending (or descending) order, above and below which lie an equal number of values. See *Federal Judicial Center Reference Manual on Scientific Evidence*, "Reference Guide on Statistics" 360-61, 400 (1994); Charlotte-Mecklenburg Hosp. Auth. v. North Carolina Indus. Comm'n, 443 S.E.2d 716, 731 n.6 (N.C. 1994); *Webster's II New Riverside University Dictionary* 737 (1988).

201. That Mr. Ellis' RMFP study omits a rigorous analysis of the leased acreage associated with the 2,058 transactions included therein is, evidently, consistent with Exxon's apparent overall strategy of avoiding the issue of on-the-lease transportation, in the hope that the court would do likewise. As noted above, Mr. Pohler's gas comparability study failed to address the geographical configuration and size of the leases associated with the 2,058 Ellis transactions. Moreover, Exxon instructed Mr. Platt to disregard the cost of on-the-lease transportation for purposes of his transportation cost study. Tr. 2476, 2481-82; PX 5 at 1 (Platt's admission to this effect).

202. Tr. 1214. With respect to the 2,058 transactions in his RMFP sample, Mr. Ellis testified that he had 1,557 contract files available, 1,037 of which he characterized as "reasonably complete." Tr. 931. Further, as noted above, in connection with our discussion of Mr. Pohler's gas comparability study, the court's examination of a substantial number of the gas purchase contracts in evidence (PX 14a and PX 14b) disclosed that such contracts generally recite a metes-and-bounds legal description of the leased acreage dedicated to the contract, and often include a map or plat of the dedicated acreage. Although such documentation is not contained in every contract file we reviewed, it nonetheless appears with sufficient frequency to imply that Mr. Ellis could have included several hundred additional contracts in his median lease size determination, had he been so inclined.

We note, further, that Exxon's basic contention -- that on-the-lease transportation is irrelevant to the sale price of natural gas because it typically covers only short distances -- extends to *all* 2,058 of the transactions in Mr. Ellis' RMFP study, not just the 649 purported on-the-lease transactions. This is so because each of the 1,409 transactions in Mr. Ellis' report with an *off*-the-lease delivery point (*i.e.*, the transactions given the "Account 801" designation therein) necessarily involved *some* on-the-lease transportation of the gas, *i.e.*, from the wellhead or separator to the edge of the lease. Yet, Mr. Ellis admitted that he made no attempt to determine the median lease size of the 1,409 off-the-lease transactions in issue. Tr. 1214.

203. The 649 on-the-lease transactions in Mr. Ellis' RMFP study involved roughly 276 Bcf of gas. PX 6, SubX G, at 16. Mr. Platt's well identification study (PX 5, SubX 9) purports to identify the wells associated with 602 such transactions, which involved approximately 271 Bcf of gas, or about 98% of the gas associated with all 649 on-the-lease transactions. With respect to the 602 transactions with identified wells, the volumetric proportion of the gas relating to multiple-well transactions can be broken down, in summary, as follows:

	Volume (Bcf)	Percentage of Volume
All on-the-lease transactions with identified wells	271	100%
On-the-lease transactions with 2 or more wells	234	86%
On-the-lease transactions with 5 or more wells	172	63%
On-the-lease transactions with 10 or more wells	105	39%
On-the-lease transactions with 15 or more wells	81	30%.

The foregoing demonstrates that multiple-well transactions exert a substantial influence upon the volume-weighted average price of the gas, *i.e*., Mr. Ellis' proposed RMFP.

204. Further, Mr. Pohler testified that gas wells are typically drilled on spacing of 300 to 400 acres per well. Tr. 214. We note also that FERC, pursuant to its promulgation of regulations authorizing the payment of gathering allowances under section 110 of the Natural Gas Policy Act of 1978, determined that gas well spacing "commonly ranges from 640 acres (1 mile square) to 160 acres (1/4 mile square)." *Staff Report: Cost Analysis of Gathering and Compression and Recommendation of Related Allowances Under Section 110 of the Natural Gas Policy Act*, 45 Fed. Reg. 84814, 84816 (Dec. 16, 1980). Although the lower end of the range cited by FERC, 160 acres per well, could be taken to suggest that Mr. Ellis' 233-acre estimate of the median lease size has some basis in fact, it must be kept in mind that FERC's determination reflects nationwide well spacing practices, whereas the testimony of Messrs. Buie and Pohler specifically relates to typical well spacing in the Texas Gulf Coast/East Texas region and, thus, is more probative.

205. To name but a few examples, transaction L0170, *supra*, involved 31 wells situated on more than 40,000 leased acres, which works out to approximately 1,290 acres, or 2 square miles, per well. Tr. 783; PX 5, SubX 9, PL1-03348. Transaction L0226 involved a single well located on approximately 1,000 dedicated acres. PX 14a at L016937-39; PX 5, SubX 9, at PL1-03400. Similarly, transaction G3447 involved four wells located on 5,760 dedicated acres, which equates to 1,440 acres per well. PX 14a at U006336-37; PX 5, SubX 9, at PL1-03086.

206. We acknowledge, of course, that multiple-well transactions frequently involve large volumes of gas, implying that the costs of on-the-lease gathering are spread over more units of gas, lowering the per-Mcf cost. But that is no reason to blandly assume, as Exxon does, that the per-Mcf cost of on-the-lease gathering is always *zero*.

207. Daubert and Kumho Tire are, of course, concerned with the *admissibility* of expert opinion testimony under Federal Rule of Evidence 702. Here at bar, in contrast, we address the *sufficiency* of expert opinion testimony already in the record, i.e., Mr. Ellis' opinion (Tr. 1222) that on-the-lease transportation is valueless. See Conde v. Velsicol Chem. Corp., 24 F.3d 809, 813 (6th Cir. 1994) (noting aforesaid distinction). However, our application of the Daubert standard of evidentiary reliability is consistent with the "hard look" doctrine, under which the district courts have a duty to evaluate the reliability of expert opinion testimony, even after such testimony is in the record, in order to determine whether the case should go to the jury. Turpin v. Merrell Dow Pharmaceuticals, Inc., 959 F.2d 1349, 1350, 1352 (6th Cir.), cert. denied, 506 U.S. 826 (1992), cited with approval in Daubert, 509 U.S. at 596. See also Conde, 24 F.3d at 813 (expert testimony, even if admitted, remains subject to Daubert reliability standard). Here at bar, sitting as the trier of fact, this court thinks that it is clear beyond cavil that the Daubert reliability standard may properly be taken into consideration in evaluating the probative weight of expert opinion testimony already in the record. See Wessmann v. Gittens, 160 F.3d 790, 805 (1st Cir. 1998) (applying Daubert to discredit expert testimony admitted in bench trial).

208. The arithmetic mean, or average, is the sum of a group of numerical values, divided by the number of values in the group. See *Federal Judicial Center Reference Manual on Scientific Evidence*, "Reference Guide on Statistics" 360-61, 400 (1994); Charlotte-Mecklenburg Hosp. Auth, 443 S.E.2d at 731 n.6; *Webster's II New Riverside University Dictionary* 736 (1988).

209. If very large lease sizes are truly atypical, as Exxon suggests, we could make appropriate adjustments, such as recomputing the mean lease size with the outliers discarded. *Federal Judicial Center Reference Manual on Scientific Evidence*, "Reference Guide on Statistics" 362 (1994).

210. The overbreadth of Mr. Platt's assumption mainly stems from the fact that he examined only 20 of the 1,409 off-the-lease transactions in Mr. Ellis' RMFP study (*i.e*., transactions with the "Account 801" designation therein). Tr. 2434. In an attempt to determine the proximity of pipeline facilities to the producing gas fields relating to those 20 transactions, Mr. Platt visually scrutinized the Texas Gulf Coast/East Texas region, from which he inferred that the 20 transactions he examined involved off-the-lease transportation of no more than one mile. Tr. 2434; PX 5, SubX 26 (map). Lacking any other data with which to make a more precise footage, or mileage, determination, Mr. Platt adopted the assumption that one mile was a representative transportation distance for all 1,409 of the off-the-lease transactions in issue. Tr. 2438-39. We view Mr. Platt's one-mile assumption as sheer conjecture. At trial, Mr. Platt attempted to illustrate the foregoing methodology, using a demonstrative enlargement of the map in question (PX 5, SubX 26), but the court found Mr. Platt's testimony vague and his methodology erratic. Tr. 2432-51. Mr. Platt's subjective "eyeballing" of a map can hardly be said to be a rigorous methodology calculated to produce reasonably consistent distance estimates, because anyone could look at the same map and come up with a different opinion. See Ayers, 887 F.Supp. at 1060.

211. See, e.g., Texas Gulf Coast Area Rate Proceeding, 45 F.P.C. at 706-07, 718-19 (establishing gathering allowance of only $0.004/Mcf for gas produced in the Texas Gulf Coast area, effective August 1, 1971, through December 31, 1975).

212. The sensitivity of federal energy policy makers to public perceptions that the oil and gas industry was reaping windfall profits, as a consequence of the skyrocketing market prices of oil and gas in the 1970s and early 1980s, is well documented. For example, as noted above, Congress reacted to the public outcry over such purported windfall profits in 1975, by generally repealing the allowance for percentage depletion as applicable to the major integrated oil and gas producers. See Engle, 464 U.S. at 211. Similar concerns later prompted Congress to enact the Crude Oil Windfall Profit Tax Act of 1980, Pub.L. No. 96-223, Title I, § 101(a)(1), 94 Stat. 229, 230 (April 2, 1980), which imposed an excise tax (since repealed) upon sales of crude oil. See generally 26 U.S.C. §§ 4986-4990 (1981).

213. In fact, the $0.07/MMBtu *minimum* gathering allowance permitted under the FERC methodology demonstrates that Mr. Platt's estimates of gathering costs (*i.e*., zero if on-the-lease, and a flat $0.01/Mcf if off-the-lease) are grossly understated. In order to make this comparison, two adjustments are necessary. First, the FERC gathering allowance must be restated from 1980 dollars to 1975 dollars. See 45 Fed. Reg. at 84816 (FERC gathering cost study, issued December 16, 1980); 48 Fed. Reg. at 44496 n.12, 44504 (gathering allowance generally applicable to gas delivered on or after July 25, 1980). Based upon a tabulation of gross national product implicit price deflators in Mr. Platt's report (PX 5, SubX 18), we note that the average inflation indices for 1975 and 1980 were 44.6 and 60.4, respectively (1992 being the baseline index of 100). Applying the foregoing inflation indices, the FERC post-NGPA minimum gathering allowance of $0.07/MMBtu, in 1980 dollars, equates to approximately $0.052/MMBtu in 1975 dollars ($0.07 x 44.6 ÷ 60.4). Second, the FERC gathering allowance must be converted from Btu pricing to volumetric (per Mcf) pricing. Mr. Pohler's gas comparability study indicates that the average Btu content of Texas Gulf Coast/East Texas gas was 1.086 MMBtu/Mcf in 1975. PX 1, SubX 27. Converted to volumetric terms, the FERC post-NGPA minimum gathering allowance (restated at $0.52/MMBtu in 1975 dollars) equates to about $0.056/Mcf ($0.052 x 1.086). Thus, adjusted for inflation and converted to volumetric terms, the *minimum* gathering allowance under the FERC post-NGPA methodology ($0.056/Mcf) is more than five times greater than the *maximum* gathering cost proposed by Mr. Platt ($0.01/Mcf).

214. Specifically, the court hereby excludes transactions F0004, F0033, F0545, F0563, F0611, F0623, F0627, F0631, F0659, F0859, F0861, F0865, F0885, F0887, F0915, F1267, F1333, F1372, F1390, F1400, F1406, F1409, F1412, F1418, F1421, F1424, F1427, F1430, F1433, F1436, F1439, F1442, F1444, F1445, F1477, F1596, F1616, F1624, F1710, F2689, F2695, F2697, F2698, F2700, F2701, and F2705.

215. Order filed November 24, 1998, at 4 (directing the parties to file "a joint stipulation listing *each and every* transaction as to which the related contract file, PX 14a and/or PX 14b, contains a reservation of processing rights to the seller of the natural gas in question" (emphasis added)); Joint Stipulation, filed December 22, 1998 (listing 406 such transactions); Joint Supplementary Stipulation, filed January 21, 1999 (listing 94 additional transactions).

216. PX 14a at H0001118 (transaction G0806); PX 14b at H0105098 (G0922); PX 14b at L0084374-377 (L0017); PX 14b at L00116036-038 (L0170); PX 14a at L0030129 (L0498).

217. We note that, of the 186 interstate transactions in issue that involve reserved processing rights, only the 58 *de jure* Account 800 transactions remain viable candidates for inclusion in the RMFP computation. The 128 *de jure* Account 801 transactions involving reserved processing rights are, of course, included among the 820 *de jure* Account 801 transactions that we have disqualified, as explained above, as a consequence of Exxon's failure to demonstrate that the sale price of the gas in such transactions included no material value added by transportation, as follows: (i) the 774 *de jure* Account 801 transactions that are properly designated as such in Mr. Ellis' RMFP study (PX6, SubX G), 87 of which involved reserved processing rights; and (ii) the 46 *de jure* Account 801 transactions that Mr. Ellis redesignated as *de facto* Account 800 transactions, 41 of which involved reserved processing rights.

218. In addition to its burden of proof argument, *supra*, the Government also asserts that the mere *existence* of a contractual reservation of processing rights to the producer disqualifies a transaction from inclusion in the RMFP computation, on the ground that no "sale" occurs because the producer does not surrender all of its right, title, and interest in the gas upon delivery to the purchaser, *even if the producer never exercises its right to process the gas*. Defendant's Reply To Exxon's Memorandum On The Burden Of Proof On The Issue Of Processing, filed December 18, 1998, at 5. Given our disposition of the reserved processing rights issue, *infra*, we need not reach the merits of this novel contention, for which

the Government cites no legal authority. Curiously, the Government's argument cannot be reconciled with its own RMFP study, prepared by Mr. Robles, which includes numerous transactions involving reserved processing rights.

219. The Government correctly notes that the limited life expectancy of business records is the reason why the Federal Rules of Evidence draw a distinction between public records, which may be self-authenticating, and business records, which never are. Fed. R. Evid. 901, 902(1)-(5) (defining circumstances in which public records are self-authenticating, but making no similar provision for business records). See also Weinstein & Berger, supra, § 803.11 at 803-55 ("Records of regularly conducted [business] activity are not normally self-proving, as public records may be."); Mueller & Kirkpatrick, supra, § 8.47 at 977 (to same effect).

220. Plaintiff's Memorandum On The Completeness Of The Contract Files In The Record, filed December 4, 1998, at 4 ("Obviously, Exxon cannot represent that it has personal knowledge that each of the subpoenaed pipelines had maintained complete files on the listed transactions for over twenty years."); Tr. 931 (Ellis admission that of the 1,557 contract files he had available, only 1,037 such files were even "reasonably complete").

221. See, e.g., *McCormick On Evidence* § 54, at 220 (John W. Strong ed., 4th ed. 1992) (noting that if evidence admitted without objection "has no probative force, or insufficient probative value to sustain the proposition for which it is offered, the want of objection adds nothing to its worth and it will not support a finding") (citing cases).

222. Tr. 635-36, 722, 725-31; PX 13a, E0017315-E0017406 (Lo-Vaca "Gas Purchases By Type Of Purchase" report for the month of December 1974, used by Eakin for this purpose).

223. On similar reasoning, we reject Exxon's contention that Mr. Ellis confirmed that certain 1975 gas purchases made by intrastate pipeline companies were purchases of raw gas, by consulting GUD annual reports for the years 1977-1979, by which time intrastate pipelines were required to base their GUD filings on the NARUC Uniform System of Accounts, which segregates raw gas purchases (Accounts 800 and 801) from processed gas purchases (Account 802). Plaintiff's Memorandum On The Burden Of Proof On The Issue Of Processing, filed December 9, 1998, at 3. Just as gas producers can elect to exercise their reserved processing rights, if selling processed gas is the more profitable course of action, gas producers can also elect to *cease* processing their gas, should it later become more profitable to sell raw gas. Tr. 350 (Buie). Thus, the mere fact that a transaction was classified as a raw gas purchase, in a GUD annual report filed for one or more of the years 1977-1979, does not necessarily prove that the intrastate pipeline company in question bought raw gas under the same contract in 1975.

224. Tr. 364-68; PX 2 at 22-23; PX 6, SubX D. As noted above, unlike transactional classifications made under the NARUC Uniform System of Accounts, in an annual report (Form 2) duly filed by an interstate pipeline company with the FPC, transactional classifications made by intrastate pipeline companies, such as HPL, in their 1975 GUD annual reports are not entitled to a rebuttable presumption of correctness under Panhandle, 187 Ct. Cl. at 151-52, 408 F.2d at 704-05. See Exxon I, 88 F.3d at 977-79 (limiting scope of Panhandle presumption to "FPC forms" and "FPC transactions").

225. This holding disposes of Exxon's contention that the burden of production, *i.e.*, the burden of going forward with the evidence, shifted to the Government to affirmatively prove that reserved processing rights were, in fact, exercised. There are no exceptional circumstances, here at bar, that might justify shifting that burden, as might be the case if the Government were shown to have demonstrably superior access to the requisite proof. See Brush v. OPM, 982 F.2d 1554, 1561 (Fed. Cir. 1992). Similarly, nothing in the record suggests that exercises of reserved processing rights were such a rarity, in the Texas

Gulf Coast/East Texas region in 1975, as to warrant shifting the burden to the Government to affirmatively prove the occurrence of such exercises.

226. Plaintiff's Memorandum On The Burden Of Proof On The Issue Of Processing, filed December 9, 1998, at 9.

227. In making that inquiry, with respect to the 319 intrastate transactions in which processing rights were reserved to the producer, we focus upon the 130 *de facto* Account 800 (*i.e*., intrastate, on-the-lease transactions) that involved reserved processing rights, since those 130 transactions have not already been disqualified on separate grounds. Concomitantly, we disregard the 189 *de facto* Account 801 (*i.e*., intrastate, off-the-lease) transactions that involved reserved processing rights, which are included among the 635 *de facto* Account 801 transactions that we have disqualified, *supra*, due to Exxon's failure to demonstrate that the sale price of the gas in such transactions was not tainted by transportation of the gas away from the wellhead before sale.

228. As discussed in the preceding section of this opinion, although 100 of the 158 *de jure* Account 800 transactions involved reserved processing rights, those 100 transactions are, under the Panhandle presumption, deemed to be sales of unprocessed gas.

229. In total, there are 130 *de facto* Account 800 transactions involving reserved processing rights. Of those 130 transactions, 126 are disputed and four are agreed by the parties to qualify as wellhead sales, as delineated above.

230. Specifically, upon examining Mr. Ellis' RMFP workpapers (PX 6, SubX E), the court ascertained that no more than 43 of the 603 transactions yet under consideration were free of both compression and dehydration. Subexhibit E to Mr. Ellis' report lists 56 transactions that purport to be sales of uncompressed, undehydrated gas. Fourteen of those transactions are included among the 46 *de jure* Account 801 transactions that Mr. Ellis redesignated as *de facto* Account 800 transactions, in accordance with Exxon's invalid on-the-lease criterion, *supra*, and have already been excluded from further consideration. To the 42 transactions that remain (of the 56 transactions listed in Mr. Ellis' Subexhibit E), we add transaction F1976, which is elsewhere portrayed in Mr. Ellis' report as a transaction free of both compression and dehydration (PX 6, SubX F, at 7), yet omitted, without explanation, from the tabulation in Subexhibit E. It must be noted, however, that not all of the 43 transactions in question qualify for inclusion in the RMFP computation, merely because such transactions are untainted by compression or dehydration. A significant number of those 43 transactions are disqualified on alternate grounds, *i.e*., Exxon's failure to demonstrate that the gas was not transported a material distance away from the wellhead, nor processed for the extraction of liquefiable hydrocarbons, prior to sale.

231. It is not infrequently the case that courts, upon determining that a principle originating in an earlier dictum is sound, will subsequently incorporate such principle into the law. This is no less true in RMFP cases, it seems, than in any other area of the law. For example, the Panhandle presumption, *supra*, is arguably the progeny of dicta. See Panhandle, 187 Ct. Cl. at 152, 408 F.2d at 704-05 ("It would be better, *in any future litigation of this kind*, if the parties relied solely upon information contained in said forms" (emphasis added), *i.e*., annual reports (Forms 2) filed by interstate pipeline companies with the FPC); Exxon I, 88 F.3d at 977 ("Based on its context, we read Panhandle as creating a rebuttable presumption that filed [FPC] annual reports constitute prima facie proof of the transactions they represent.").

232. The court does not mean to suggest that the "preferable" method should become the rule in every RMFP case. On the contrary, even without the added complexity of the "preferable" method, which requires a determination of the typical costs of compression and dehydration, the "calculation of the

RMFP is a difficult and sometimes onerous task." Exxon I, 88 F.3d at 976. Thus, in our view, the "preferable" method should be used *only* when it is not otherwise feasible to assemble a sample of transactions that is large enough to give reasonable assurance that the resultant RMFP is truly "representative." Conversely, where a truly representative sample of pre-compression, pre-dehydration wellhead sales of comparable raw gas in the taxpayer's market area can be assembled, there is no justification for resorting to the "preferable" method, and the RMFP should be computed in straightforward fashion. That being said, additional guidance from our superior court, as to the circumstances in which the "preferable" method of computing an RMFP is properly applicable, would add some welcome clarity to this area of the law.

233. Mr. Ellis testified that his consulting firm alone devoted over 6,000 manhours, over a period of approximately 14 months, to the preparation of his RMFP study. Tr. 921. Similarly, Messrs. Buie, Eakin, and Hague testified that they each spent several months reviewing the gas purchase contract files of their respective former employers, Houston Pipe Line Company, Lo-Vaca Gathering Company, and United Gas Pipe Line Company. Tr. 387 (Buie, two to three months), 654 (Eakin, four months), 844 (Hague, three to four months).

234. By "group of connected transactions," we refer to the situation in which a single pipeline company gas purchase contract governed multiple gas purchase transactions, some or all of which involved less than one Bcf, but exceeding one Bcf in the aggregate. For example, transactions G0994, G0995, G0996, G1026, and G1027 relate to the same gas purchase contract, dated December 1, 1973, between Houston Pipe Line Company, as buyer, and Mitchell Energy & Development Corp., as producer and seller, covering Mitchell's gas production from several wells located in the Hortense and Seven Oaks Fields in Polk County, Texas. PX 6, SubX I, at 49-50; PX 14b at H0114909. Transactions G0994, G0995, G0996, and G1027 each involved less than one Bcf, but fell within the scope of our inquiry by virtue of their connection with transaction G1026, which involved 1,003,626 Mcf (slightly over one Bcf).

235. For example, the contracts relating to transactions L0017 and L0170, *supra*, dated August 1, 1975, and September 25, 1974, respectively, between Lo-Vaca Gathering Co. as purchaser and Gulf Oil Corp. as producer and seller, reserved to Gulf the right to process its gas before delivery. PX 14b at L0084374-377 (L0017); PX 14b at L00116036-038 (L0170). However, a Lo-Vaca internal memorandum dated January 27, 1976, clearly indicates that Gulf had not yet exercised its processing rights as of that date -- nor, by necessary implication, during 1975. PX 14b, L0084008-L0084009. Said memo repeatedly refers to such an exercise in the prospective sense, *i.e*., as an event that had not yet occurred. See, e.g., id. at L0084009 (stating that "*if* Gulf elects to process its gas, . . . it *would* be necessary for [Lo-Vaca] to work out some additional details" with certain third parties (emphasis added)).

236. The 18 transactions for which the producer's reserved processing rights went unexercised in 1975 include transactions L0017, L0170, G0695, G0907, G0908, G0994, G0995, G0996, G1026, G1027, G1029, G1030, G1031, G1032, G1075, G1076, G1077, and G3783. Of the aforementioned 18 transactions, the Government has conceded that transactions G0695, G1075, G1076, and G1077 were wellhead sales of raw gas. Even so, the court reviewed the contract files underlying those four transactions in order to confirm that the Government's concession has a rational basis in fact.

237. It is essential to note that, in making our determinations as to the exercise or non-exercise of reserved processing rights, relative to the 130 transactions in question, the court received no meaningful assistance from plaintiff. At trial and thereafter, Exxon failed to go forward with its evidence in a manner calculated to *disprove* that any reserved processing rights in issue were exercised in 1975. The reports submitted by Exxon's experts, Exxon's post-trial proposed findings of fact, and Exxon's several supplemental post-trial submissions on the subject of reserved processing rights, furnish *no* pointed citations to any document contained within a contract file in PX 14a and PX 14b, for the specific purpose

of affirmatively demonstrating that a producer declined to exercise its reserved processing rights in 1975. Instead, Exxon apparently relies exclusively upon its untenable proposed negative inference, *i.e*., that where a contract file, the completeness of which is unproven, gives no indication that the producer exercised its reserved processing rights, the producer actually sold unprocessed gas. Thus, with respect to the pertinent contract files that we did *not* exhaustively review, *i.e*., the contract files underlying approximately 80 of the disqualified 112 transactions, Exxon has no room to complain about our refusal to undertake an inquiry that was undeniably an element of Exxon's burden of proof, which Exxon itself apparently neglected to carry.

238. Although, technically, our disqualification of 112 transactions on the ground that Exxon has failed to show that the producers' reserved processing rights were unexercised, *supra*, reduces the number of transactions still under consideration from 433 to 321 transactions, the transportation issue touches *all* 433 transactions. Thus, with respect to the 112 transactions disqualified due to reserved processing rights, the court shall consider whether transportation, prior to sale, is an alternate ground for disqualification, as well.

239. Tr. 574-75 (Buie), 812-13 (Eakin), 895-96 (Ellis). This view is, of course, the natural consequence of Exxon's expansive contention that the boundaries of the producer's leased acreage conclusively define "the immediate vicinity of the well," irrespective of the size of such leased acreage. Thus, according to Mr. Ellis, the term "immediate vicinity of the well" denotes a larger physical area in the case of a 10,000-acre lease than it does in the case of a 10-acre lease. Tr. 895. Similarly, when asked about the circumstances in which he would consider a delivery point to be located "near" the well, Mr. Buie gave the following explanation:

If you took a 25,000-acre lease, and you asked me -- and the delivery point was within a mile of that well, and you say "Mr. Buie, is that delivery point near that well[?]," yes, it would be near that well. If you have a 40-acre lease and it's 2,000 feet away, I would say, no, it's not near the well. "Near" is a relative term.

Tr. 574. See generally Tr. 566-75 (counsel for defendant's inconclusive efforts to get Mr. Buie to express the terms "near" and "immediate vicinity" in terms of distance).

240. Tr. 1940-41, 2081-82 (admissions of Martin and Robles to this effect).

241. Further, if the Government wants to define "the immediate vicinity of the well" with such precision, by reference to a 500-foot criterion, we note that it is within the Secretary's power to amend Treas. Reg. § 1.613-3(a), so as to add such a requirement. Until that time, "it is not within our judicial powers to legislate in his stead." Exxon I, 88 F.3d at 974-75 (citing Hugoton II, 172 Ct. Cl. at 463, 349 F.2d at 430).

242. See, e.g., PX 14a at S076868 (transaction G3783), S0065882 (G3781), H005703 (G1029, G1030, G1031, G1032), H0060954 (G0990, G0991), H0055011, H0055067 (G1002); PX 14b at J0006588 (G3095), L0084368 (L0017), H0114913 (G0994, G0995, G0996, G1026, G1027), H0108462 (G0997), H0119000 (G1075, G1076, G1077).

243. See, e.g., PX 14a at S070759, S070613, S070691 (transaction G3810), S080058, S080082 (G3776), S0066099, S0066198 (G3781); PX 14b at L00116027 (L0170).

244. See, e.g., PX 14a at S076843, S077277, S077283, S077286 (transaction G3783); PX 14a at S070756 (G3810); PX 14a at S0020602, S0020659-660 (G3816); PX 14b at L0084222-240, L0084320 (L0017); PX 14b at L00115386-L00115426, L00116000 (L0170); PX 14b at H0119170, H0119261-267 (G1075, G1076, G1077); PX 14a at H0026703, H0026828, H0026843-844 (G0907, G0908); PX 14a at

H0060978, H0061030 (G0990, G0991, G0997, G0994, G0995, G0996, G1026, G1027, G1029, G1030, G1031, G1032).

245. The court also disqualified any intrastate transaction for which we could not locate a corresponding contract file in PX 14a or PX 14b, due to our resultant inability to confirm that such transactions were sales in the immediate vicinity of the well. See, e.g., PX 6, SubX I, at 46 (tabulation in Ellis report of cross-references to underlying contract files, omitting any cross-reference to a contract file relating to transaction G0865). On similar grounds, the court disqualified any intrastate transaction for which Mr. Platt's well identification study fails to identify any wells. Lacking knowledge of the number of wells associated with a transaction, one cannot rationally conclude that the producer was *not* gathering gas from multiple wells to a common delivery point, thereby adding value to such gas. See, e.g., PX 5, SubX 6, at 94 (Platt report, listing no identified wells associated with transaction G0831).

246. Ten of Lone Star's *de facto* Account 800 gas purchases from producers with multiple wells were disqualified. As to six of those transactions (G3777, G3788, G3806, G3813, G3818, and G3821), the court was unable to locate a corresponding contract file in PX 14a or PX 14b. PX 6, SubX I, at 58 (Ellis report, no citations to PX 14a or PX 14b for said six transactions). With respect to each of the other four disqualified transactions (G3779, G3785, G3819, and G3820), we found that the related contract file was inconclusive as to whether the producer was gathering gas from its multiple wells, prior to sale, to a common delivery point.

247. For example, Mr. Platt's report indicates that 10 of the 12 wells associated with transaction L0107 made no deliveries of gas to Lo-Vaca until 1975. PX 5, SubX 9, at PL1-03295.

248. At trial, Mr. Eakin sought to demonstrate how gas purchases that Lo-Vaca allegedly made at the wellhead in 1975 could be traced back to Account 41 designations in Lo-Vaca's December 1974 "Gas Purchases By Type Of Purchase" report (PX 13a, E0017315-E0017406). Tr. 675, 725-30. In order to test the accuracy of Mr. Eakin's methodology, the court analyzed the largest 42 purported wellhead purchases made by Lo-Vaca in 1975, corresponding to roughly 80% of the total volume (Mcf) and 86% of the total dollar value of the 144 gas purchases that Lo-Vaca allegedly made at the wellhead in 1975. PX 4, SubX D, at 1-4 (tabulation of said 144 transactions in Eakin report). We determined that, in terms of volume, no more than about 45% of the gas associated with Lo-Vaca's largest 42 purported wellhead purchases could be traced to an Account 41 classification in Lo-Vaca's December 1974 "Gas Purchases By Type Of Purchase" report.

Further, the court observes that nothing in the record establishes that Lo-Vaca's accounting personnel routinely and consistently classified gas purchases under Account 41 (purported to represent wellhead purchases) in an accurate manner. Mr. Eakin admitted to having no personal knowledge of whether Lo-Vaca had ever conducted an audit for the purpose of verifying the accuracy of the Account 41 designations in its books and records. Tr. 739-40, 744-46.

249. Tr. 550 (DX 45 admitted), 553 (Buie admission).

250. Tr. 555.

251. Tr. 550, 556, 561-65. Counsel for Exxon also instructed Mr. Buie to circle any transaction for which the contract defined the delivery point as being "in the immediate vicinity of the well," but none of the HPL contracts that he reviewed used such language. Tr. 563-64.

252. The court by no means suggests that where the contract specifies a delivery point "at" or "near" the well, the transaction cannot qualify as a sale in the immediate vicinity of the well. On the contrary, we

merely emphasize our inability to determine, on this record, whether Mr. Buie's conclusions regarding the transactions he circled on DX 45 are truly the product of his personal recollection of such transactions, which took place over 22 years before this case went to trial.

253. Tr. 512-14 (no firsthand knowledge of well site pertinent to transaction G1105), 339-62 (testimony regarding transaction G1095, but failing to address the location of the delivery point or its physical proximity to the producer's wells), 532-35 (Buie's inability to articulate any specific facts within his knowledge that led him to conclude that HPL bought gas in the immediate vicinity of the wells, rather than after the producer had transported the gas away from such wells, as contemplated under the contract), 483, 521-25 (conflicting testimony regarding the timing of Buie's purported visits to the well sites relating to transactions G0875 and G0880).

254. On similar grounds, we find that Mr. Eakin's alleged personal recollection of various 1975 gas purchases made by Lo-Vaca Gathering Co., his former employer, is without substance. Specifically, regarding transaction L0107, Mr. Eakin admitted that he had no firsthand knowledge of the property on which the producer's wells were situated. Tr. 815. With respect to transaction L0336, Mr. Eakin likewise admitted that he had no personal knowledge of the physical location of the delivery point, and that he did not know whether the producer had transported the gas away from its wells before sale. Tr. 692-95, 720-21, 758-60. Rather, he merely relied upon Lo-Vaca's classification of transaction L0336 under Account 41 in its internal accounting records for the year 1974. Tr. 722. See also Tr. 791-96 (same admissions relative to transaction L0498). However, as explained herein, *supra*, such designations in Lo-Vaca's 1974 accounting records fail to establish the character of gas purchases that Lo-Vaca made in 1975.

255. Those 22 transactions are numbers G0907, G0908, G0990, G0991, G0994, G0995, G0996, G0997, G1002, G1026, G1027, G1029, G1030, G1031, G1032, G3776, G3781, G3783, G3810, G3816, L0017, and L0170. Of course, as delineated above, the court has also determined that each of the foregoing 22 transactions was a sale of unprocessed gas, either because the producer had no contractual right to process its gas, or because such processing rights, if contractually reserved to the producer, were evidently unexercised in 1975.

256. Tr. 1512-13, 1518 (Nicol), 2583-84 (Platt). As Mr. Buie put it, once a producer incurs the cost of constructing a well pad, "he also is going to put his tank battery there on that drill site 99 times out of 100." Tr. 513. A tank battery is a collection of metal tanks, situated adjacent to the separator, that are used to store the liquids, *i.e.*, water and hydrocarbon condensate, that the separator removes from the raw gas wellstream. PX 1 at 13; *Field Handling of Natural Gas*, *supra*, at 42 (drawing of separator and tank battery), reproduced at PX 1, SubX 9. See also Exxon I, 33 Fed. Cl. at 257 (similar findings as to separator and tank battery, relative to 1974).

257. Tr. 1513-16 (Nicol); DX 37-38 (photographs of well sites).

258. Tr. 2583-84, 2587. Mr. Platt described this "very short" distance as 50 feet. Tr. 2584. See also PX 52 (Platt drawing of typical single-well transaction).

259. Tr. 1572-73 (Nicol).

260. Tr. 1573 (Nicol). Conversely, where the producer is gathering gas from *multiple* wells to a *common* delivery point, Mr. Nicol explained, it is economically feasible to situate the delivery point a significant distance away from the well pad(s). This is so because gas producers can achieve economies of scale and cost savings by gathering their gas to centralized compression, dehydration, or processing facilities. Tr. 1548 (Nicol), 2557-58, 2578-81 (Platt), 2651-52 (Martin); PX 1 at 13-14 (Pohler). Indeed, Mr. Nicol testified that, in his 30-plus years of engineering experience in the natural gas industry, he has never set a

custody meter more than 500 feet from the wellhead unless the meter was being set at a common delivery point, to which the producer was gathering gas from multiple wells. Tr. 1572-73, 1580. Although we reject the Government's contention that 500 feet is the immutable outer limit on the area that constitutes "the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a), the court finds Mr. Nicol's distinction between single-well and multiple-well transactions persuasive.

261. We conclude that raw, unprocessed gas was sold in the 115 single-well transactions in question, because none of those 115 transactions involved a contractual reservation of processing rights to the producer. Joint Stipulation, filed December 22, 1998, *passim* (listing transactions agreed by parties to involve reserved processing rights). Further, the court takes pain to note that, while finding that 115 single-well, on-the-lease transactions qualify for inclusion in the RMFP computation, on this record, we do *not* consequently adopt or endorse Exxon's hospitable contention, *supra*, that a transaction in which the delivery point is located *anywhere* on the producer's "lease," expansively defined by Exxon to include an aggregation of multiple common-law oil and gas leases, with no discernible limitation upon the acreage encompassed therein, qualifies as a wellhead sale. On the contrary, we find that the 115 transactions in question occurred "in the immediate vicinity of the well," within the meaning of Treas. Reg. § 1.613-3(a), a physical area of narrower scope than Exxon's "lease." Therefore, as noted above, although each of the aforesaid 115 wellhead sales occurred on the producer's lease, it does not logically follow that every sale "on the lease" is a wellhead sale. In other words, the inference we draw, relative to each of those 115 transactions, is not just that the sale occurred "on the lease," but rather, that the sale occurred "on the lease" *and* "near the wellhead." Panhandle, 187 Ct. Cl. at 137, 162, 163, 172, 175, 408 F.2d at 696, 710, 711, 716, 717, 718.

262. The "adjusted sale price" is the actual sale price of the gas, reduced by the compression and dehydration cost deductions calculated by Mr. Platt, on Exxon's behalf, under the "preferable" method enunciated in Exxon I, 88 F.3d at 977-78. Here we make reference to the adjusted sale price, as determined by Exxon, solely for the sake of convenience, so as to facilitate comparisons of the court's RMFP sample with the alternate RMFP samples proposed by Exxon, *infra*. Thereafter, the court shall consider the adequacy of Mr. Platt's compression and dehydration deductions, and make such adjustments as are appropriate and necessary, on this record. For this reason, the summary above refers to a "tentative" RMFP in the sum of $0.6944/Mcf.

263. The RMFP controversy in the Hugoton case pertained to the years 1951 through 1957, an era of low, relatively stable natural gas prices. See Hugoton I, 161 Ct. Cl. at 305, 315 F.2d at 886 (taxpayer's wellhead sales for the years 1951-1957, averaging between 12¢ and 15 ¢ per Mcf); Hugoton II, 172 Ct. Cl. at 454, 349 F.2d at 424 (Government's proposed weighted average prices of comparable wellhead sales for 1951-1957, ranging from 7¢ to 10 ¢ per Mcf). See also Panhandle, 187 Ct. Cl. at 160, 408 F.2d at 709 (RMFPs for years 1952-1956, ranging from roughly 7¢ to 11¢ per Mcf). Thus, it is evident that during the 1950s, the price disparity between old and new contracts amounted to no more than a few cents per Mcf. In contrast, as noted above, the tentative weighted average price of the intrastate gas in our 308-transaction RMFP sample ($1.1888/Mcf) exceeds, by almost a dollar, the tentative weighted average price of the interstate gas included therein ($0.2013/Mcf).

264. The only evidence in the record that is even remotely probative of this issue is the TENRAC Report, *supra*, which indicates that the total marketed production of natural gas in Texas in 1975 was 7,485,764 MMcf, roughly 48% of which (3,622,568 MMcf) was marketed in interstate commerce. TENRAC Report at 53, 65, reproduced at DX 5, SubX 5 (Robles report). For two reasons, the court finds the foregoing statistics to be of little help. First, such statistics address *statewide* gas production, whereas the computation of Exxon's RMFP takes into account only gas produced in the Texas Gulf Coast/East Texas subregion. Second, the cited production statistics in the TENRAC Report reflect *all* marketed gas production in Texas, not just gas that was sold at the wellhead. Thus, from the production statistics in the

TENRAC Report, we decline to draw any inference regarding the relative proportions of interstate and intrastate gas that were sold at the wellhead in the Texas Gulf Coast/East Texas region during 1975.

265. DX 5 at 13, SubX 1A, 2A (99.5% interstate gas); id. at 16-17, SubX 4 (99.92% interstate gas); id. at 13-16, SubX 3 (95.1% interstate gas). At face value, the Government's proposed RMFP samples would imply that *inter*state pipeline companies were at least 20 times, and perhaps hundreds of times, more likely to buy Texas gas at the wellhead than their *intra*state competitors. Nothing in the record even remotely suggests the existence of such an immense distinction between the gas purchasing practices of interstate and intrastate pipeline companies in 1975.

266. Specifically, Exxon's 2,058-transaction sample (adjusted for the exclusion of transaction G1062 at trial, supra) includes 469,631,740 Mcf of *intra*state gas, but only 294,832,753 Mcf of *inter*state gas. PX 6, SubX G, at 11, 16, 19, 32, 51. Exxon's 288-transaction subsample contains 78,194,156 Mcf of *intra*state gas), but only 42,099,471 Mcf of *inter*state gas). PX 6, SubX F, at 4, 7. Similarly, Exxon's 56-transaction subsample includes 28,558,164 Mcf of *intra*state gas, but only 8,139,383 Mcf of *inter*state gas. PX 6, SubX E, at 1-2.

267. With respect to each of those three proposed RMFP samples, if one reduces the volume of the intrastate gas in the sample, to a quantity equivalent to the volume of interstate gas in such sample, while holding the weighted-average price of the intrastate gas constant, the resultant values fall roughly in line with the tentative $0.6944/Mcf RMFP we have computed. For example, Exxon's 2,058-transaction proposed RMFP sample contains 294,832,753 Mcf of interstate gas, at an adjusted volume-weighted average price (*i.e*., adjusted for Exxon's compression, dehydration, and transportation cost deductions) of $0.338/Mcf, and 469,631,740 Mcf of intrastate gas, at an adjusted volume-weighted average price of $1.0322/Mcf. In total, said sample includes 764,464,493 Mcf at an adjusted volume-weighted average price of $0.7645/Mcf. If the respective volumes of interstate and intrastate gas were equalized, so as to eliminate the substantial bias in favor of intrastate gas, the total adjusted volume-weighted average price would be $0.6851/Mcf (the sum of $0.338/Mcf and $1.0322/Mcf, divided by two), which compares quite reasonably with the court's tentative RMFP of $0.6944/Mcf. Upon working through the same exercise for Exxon's 288-transaction and 56-transaction proposed RMFP samples, the court determined values of $0.6814/Mcf and $0.5794/Mcf, respectively.

268. Mr. Ellis gave the court no credible assurance that the 2,058 transactions in his RMFP study are, as nearly as possible, a comprehensive sampling. Rather, he blandly opined that those 2,058 transactions were merely "*a significant portion* of [the] unprocessed gas sales" in the Texas Gulf Coast/East Texas region in 1975. Tr. 905 (emphasis added). Just *how* "significant" that portion is, however, we cannot say, on this record. Mr. Ellis' report and testimony leave no doubt that he initially considered several thousand additional transactions that were later excluded from his final RMFP study. Tr. 969-70; PX 6, SubX I. However, Exxon presented no workpapers that would permit the court to evaluate Mr. Ellis' rationale for excluding any specific transaction from his RMFP study. At trial, when asked about specific transactions that he had excluded from his study, Mr. Ellis stated that he had no recollection of such transactions and, further, that the record contains nothing that might explain his decision to exclude such transactions. Tr. 971.

269. Of the 22 transactions included in Exxon's "pristine" sample, 18 such transactions are also included in the court's 308-transaction RMFP sample. The other four transactions (L0027, L0226, L0236, and L0498) we have disqualified on the grounds that the producers in those transactions had reserved the right to process their gas, prior to sale, and the underlying contract files, in PX 14a and PX 14b, fail to affirmatively establish that such reserved processing rights were unexercised in 1975.

270. By charitably labeling the 22 transactions in question "pristine," and alleging that said transactions

satisfy the Government's strict 500-foot criterion for qualifying wellhead sales (*i.e*., a delivery point within 500 feet of the wellhead), Exxon evidently would have this court believe that these 22 transactions constitute the most narrowly drawn, nearly perfect sample of transactions that can be constructed, on this record. However, short of our devoting unreasonably time-consuming scrutiny to literally hundreds of other transactions, the court has no way to objectively verify that the 22 transactions in Exxon's "pristine" RMFP sample are, in fact, the *only* transactions in issue that satisfy the Government's 500-foot criterion, as opposed to 22 transactions that Exxon hand-picked because they would yield a generous RMFP of 81¢ per Mcf.

271. As discussed above, Exxon has failed to demonstrate that its 1975 casinghead gas production, comprising approximately 9.74% of the Exxon gas in issue, was comparable to the gas produced in the 2,058 transactions in Exxon's RMFP study, from which we have selected a subsample of 307 transactions, plus an additional wellhead sale identified by the Government, *supra*. It necessarily follows that the comparability of Exxon's casinghead gas to the gas represented in our 308-transaction RMFP sample is unproven and, further, that no RMFP has been proven with respect to Exxon's casinghead gas.

272. The 30 untainted transactions in question are shown in Appendix A, *infra*, as having no entries in the columns for compression and dehydration charges. We note, further, that those 30 untainted transactions are unjustifiably biased in favor of higher-priced intrastate gas (roughly 83% in terms of volume), at the expense of interstate gas (only about 17%).

273. Mr. Platt's compression cost study (PX 5) addresses 307 of the 308 transactions in the court's RMFP sample. His study does not address the Tejas Gas/J. M. Huber Corp. transaction identified by defendant, *supra*, inasmuch as Exxon did not include said transaction in its 2,058-transaction RMFP sample. The court has determined, however, that the sale price of the gas in the Tejas Gas/J. M. Huber Corp. transaction was untainted by compression, prior to sale, because the purchaser, Tejas Gas, clearly provided any required compression at its sole cost, as evidenced by the contract and by several letters in the contract file regarding the purchaser's installation of the required compression facilities. PX 14a at J0000908-09, J0000712-13, J0000724, J0000739.

274. Tr. 949-61, 978-79, 2343-51; PX 5 at 23, SubX 7; PX 1 at Appendix 12; PX 32. In certain cases, where no 1975 FTP data for a well was available, Mr. Platt used 1976 FTP data. Mr. Platt's usage of 1976 FTP data is acceptable, however, in that it tends to produce a conservative result. This is so because a gas well's FTP gradually diminishes over the productive life of the well, as the volume of gas in the underlying reservoir is depleted. Tr. 1527 (Nicol), 2345 (Platt). As the FTP decreases, the compression requirements increase. Thus, using 1976 FTP data, as a substitute for unavailable 1975 FTP data, tends to overstate the actual 1975 compression requirements and costs, and understate the RMFP. Tr. 2345-49.

275. Tr. 2350-51, 2358. Further, we think that the conservative nature of Mr. Platt's assumption -- that *all* producers were *always* required to deliver gas at the MDP -- is demonstrated by the failure of the Government's experts to challenge said assumption.

276. In Appendix A, *infra*, the 243 transactions involving compression before sale have an entry in the column for compression charges, representing a deduction from the sale price.

277. As noted above, although FERC's compression cost allowance methodology is not dispositive, here at bar, the court is mindful that Congress, in enacting the NGPA, charged FERC with the duty to regulate the nationwide natural gas market. Pursuant thereto, FERC undertook an exhaustive study aimed at determining the typical costs of compression, giving due consideration to industry and public commentary. Therefore, FERC's expertise in such matters is entitled to considerable weight.

278. PX 5 at 17; DX 2 at 7-8; Tr. 2367-77; FERC Staff Report, *supra*, 45 Fed. Reg. at 84814-84816. The process of compressing a gas generates heat. When the gas pressure must be substantially increased (*i.e.*, a high overall compression ratio, *infra*), multiple stages of compression are required, because the heat generated by single-stage compression would have a destructive effect on the compression equipment. *Field Handling of Natural Gas*, *supra*, at 88; Gas Processors Suppliers Association, *Engineering Data Book*, at 13-2 (10th ed. 1987), reproduced at PX 5, SubX 10; *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44503 (Sept. 27, 1983), reproduced at PX 5, SubX 15.

279. PX 5 at 17; Tr. 2373-75. See *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44503 (Sept. 27, 1983) (adopting 3.5 to 1 ratio), codified at 18 C.F.R. chap. 1, § 271.1104(d)(1)(iv)(A) (1983); Phillips Petroleum Co. et al., *Joint Initial Comments of Indicated Producers*, at 11 (March 2, 1981) (industry commentary on FERC compression cost study, recommending adoption of 3.5 to 1 compression ratio), reproduced at PX 5, SubX 15, at 46.

280. *Field Handling of Natural Gas*, *supra*, at 88; Gas Processors Suppliers Association, *Engineering Data Book*, *supra*, at 13-2; David A.T. Donohue & Karl R. Lang, *A First Course in Petroleum Technology* (1986), reproduced at PX 5, SubX 10.

281. For the Government, Mr. Nicol opined that per-stage compression ratios of 4 to 1 or 4.5 to 1 are common, Tr. 1535-36, but cited no authoritative support for this assertion. We note, further, that FERC initially proposed to base compression allowances upon a compression ratio of 4.5 to 1, but thereafter lowered its estimate of the typical compression ratio to 3.5 to 1, in response to industry comments. In reaching this conclusion, FERC stated:

The Commission staff studies adequately support the proposition that a compression ratio of 3.5 to 1 per stage of compression promotes efficient use of the compressors, is more easily ascertainable, and is the [sic] more representative of normal operations than a compression ratio of 4.5 to 1 per stage of compression. The latter ratio would cause excessive heat, result in undue wear and tear on the compressor, and require much higher fuel consumption.

Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978, 48 Fed. Reg. at 44503. The foregoing statement not only contradicts Mr. Nicol's assertion, but also indicates that the selection of a per-stage compression ratio implicates cost trade-offs, *i.e.*, between the number of stages of compression that are required, and the costs of fuel and maintenance of the compressor. As applied to a large sample of transactions involving a wide range of compression requirements, this suggests that the selection of a per-stage compression ratio is unlikely to materially distort the resultant estimate of the cost of compression, in the aggregate.

282. PX 5 at 18; Tr. 2369; Gas Processors Suppliers Association, *Engineering Data Book*, *supra*, reproduced at PX 5, SubX 14, at PL21-00047. Moreover, Mr. Platt's horsepower determination is consistent with the compression horsepower data compiled by FERC for purposes of its 1980 compression cost study, *supra*. FERC Staff Report, *supra*, 45 Fed. Reg. at 84820 (tabulation of compression ratio and horsepower data, indicating that a 73.5-hp single-stage compressor is required to compress one MMcf/day, at a per-stage compression ratio of 3.5 to 1).

283. Tr. 1530-34, 1593. Indeed, one of the engineering treatises on which Mr. Platt relied, in determining that a 75-hp compressor is required to compress one MMcf of gas per day, contradicts Mr. Nicol's view, as follows:

There are many variables which enter into the precise calculation of compressor performance.

Generalized data as given in this section [of the treatise] are based upon *averaging of many criteria*. The results obtained from these calculations, therefore, must be considered *as close approximations to true compressor performance*.

Gas Processors Suppliers Association, *Engineering Data Book, supra*, reproduced at PX 5, SubX 14, at PL21-00047 (emphasis added). From the foregoing, it is evident that, contrary to Mr. Nicol's assertion, generalized, average data *can* be used in order to formulate reasonable approximations of the cost of compression.

284. Tr. 2384-85; PX 5 at 21, SubX 17 (Platt DCF equation). Mr. Platt's calculation of the annual capital cost recovery charge follows the approach taken by FERC in its 1980 compression cost study, which also applied a DCF analysis to spread the compressor's capital cost over an assumed 15-year useful life. FERC Staff Report, *supra*, 45 Fed. Reg. at 84819.

285. Tr. 2635. During the years 1976-1978 and 1980-1984, Mr. Martin was employed as a bank vice president specializing in oil and gas lending. Tr. 1872-77; DX 1 at Appendix A.

286. We reject Mr. Martin's claim that an 18% discount rate is required. The underlying premises of Mr. Martin's contention -- that 10% was the minimum cost of funds to a non-prime-rate borrower in 1975, and that 8% was an appropriate risk premium for an investment in a field compressor -- are supported by nothing but his bare opinion to this effect.

287. Tr. 2383-84; PX 5 at 21-22; FERC Staff Report, *supra*, 45 Fed. Reg. at 84819, 84822 (App. B, Sch. 1), reproduced at PX 5, SubX 15, at 23, 27.

288. Mr. Martin's report expresses the view that an annual operating and maintenance cost allowance of 15% of the capital cost of the compressor is more appropriate, because "it would be unusual for an engine to last more than 3 to 4 years without a major overhaul at considerable expense." DX 1 at 19. However, the foregoing is merely Mr. Martin's naked opinion, for which his report cites *no* authoritative source of factual support. Further, Mr. Martin seeks to double-count the risk of mechanical breakdowns, given his contention, *supra*, that the cost of capital for a typical field compressor must include a substantial risk premium, in part to reflect the possibility that the compressor might suffer a premature breakdown and require an overhaul.

289. In contrast, Mr. Platt determined that the average non-fuel cost of compression was $0.0363 per Mcf. PX 5 at SubX 17. The difference between Mr. Platt's figure and the $0.0482/Mcf calculated herein is attributable in part to our load factor adjustment, and in part to our upward adjustment to the annual capital cost recovery charge, *supra*.

290. Tr. 2395-96; PX 5 at 22, SubX 11; Society of Petroleum Engineers, *Petroleum Engineering Handbook*, at 39-24 (undated excerpt), reproduced at PX 5, SubX 19. A horsepower-hour is a measure of power, expressed in terms of the work performed in one hour. "Power is the rate of doing work or the amount of work done in a specific unit of time. It is calculated in foot-pounds per minute. One horsepower equals 33,000 foot-pounds per minute." *Field Handling of Natural Gas*, *supra*, at 86. Thus, one horsepower-hour equals 1,980,000 foot-pounds per hour (60 x 33,000).

291. According to Mr. Platt's fuel usage equation, the per-stage fuel use in Mcf = (75 hp, the hp per MMcf of gas compressed) x (10 cf/hp-hr, the fuel usage rate) x (.001, the number of Mcf per cf) x (24, the number of hours per day) x (.001, one Mcf of compressed gas, restated in MMcf). PX 5 at SubX 20 n.3. Thus, to compress one Mcf through one stage requires 0.0180 Mcf of fuel, as follows: fuel use in Mcf = 75 x 10 x .001 x 24 x .001 = 0.0180 Mcf.

292. PX 5, SubX 20 n.1. Regarding the subtraction of 25 psi from the FTP in the foregoing equation, Mr. Platt attributed the need for this adjustment to "pressure losses," which evidently refer to normal mechanical inefficiencies or gas leakage from the compressor. PX 5 at 23. This adjustment is conservative in effect, in that it tends to increase the overall compression ratio, which in turn tends to increase the number of required stages of compression.

293. Stated differently, as noted in Mr. Platt's report, one stage is required when the overall compression ratio is between 1 and 3.5, two stages when the overall compression ratio is between 3.5 and 12.25 (3.5 x 3.5), three stages when the overall compression ratio is between 12.25 and 42.875 (3.5 x 3.5 x 3.5), and so on. PX 5 at SubX 20 n.2.

294. Here we do not refer to the situation in which Mr. Platt had no 1975 FTP data for a well, but utilized 1976 FTP data as a substitute, *supra*. As noted above, that substitution tends to produce a conservative result, *i.e*., overstate the actual 1975 compression requirements. Rather, we refer to the situation where Mr. Platt had no FTP data, of *any* vintage, for a well in issue.

295. Tr. 2362-66, 2401, 2624-25; PX 5 at 23-24. There is no way to verify, on this record, that the aforesaid aggregate weighted average compression cost is truly $0.04508/Mcf, inasmuch as Mr. Platt's report omits workpapers illustrating the computation of this item.

296. Specifically, using Mr. Platt's overall compression ratio formula, *supra*, where the FTP is 32 psi, four stages of compression will raise the pressure of the gas to 1,050 psi (3.5 x 3.5 x 3.5 x 3.5 x (32 psi FTP - 25 psi)). At pressures above roughly 48 psi, three stages of compression will suffice (*i.e*., 3.5 x 3.5 x 3.5 x (49 psi FTP - 25 psi) = 1,029 psi).

297. Of the thousands of wells with FTP data tabulated in Mr. Platt's study, only a minute fraction thereof have FTPs below 32 psi. PX 5 at SubX 7 *passim*. Thus, a five-stages assumption for wells lacking FTP data would, in our view, be unrealistic. Further, we duly note that FERC, pursuant to its 1980 compression cost study, determined that "most gas compression can be accomplished using three stages or less." FERC Staff Report, *supra*, 45 Fed. Reg. at 84815. However, the mere fact that FERC found that "most" compression can be accomplished with three stages or fewer fails to convince the court that a three-stages assumption for well lacking FTP data would be sufficiently conservative for present purposes. By adopting a four-stages assumption for wells lacking FTP data, we minimize the possibility that the costs of compression for such wells will be understated.

298. As noted above, Mr. Pohler's gas comparability study indicates that raw gas produced in the Texas Gulf Coast/East Texas region in 1975 had an average heating value of 1.086 MMBtu/Mcf. PX 1 at 31, 39. Thus, on the average, one MMBtu of heating value equates to roughly 0.9208 Mcf (1.0/1.086), and FERC's $0.06/MMBtu compression cost allowance translates to approximately $0.0652/Mcf ($0.06/0.9208).

299. As noted above, the table of gross national product implicit price deflators in Mr. Platt's study reports average inflation indices of 41 for 1975, and 60.4 for 1980. PX 5 at SubX 18. Thus, $0.0652/Mcf x 41/60.4 = $0.441/Mcf in 1975 dollars. The foregoing inflation adjustment addresses the period 1975-1980 because FERC's compression cost study was prepared in 1980 (FERC Staff Report, 45 Fed. Reg. at 84814), and FERC's final compression cost allowance regulations, though promulgated in 1983, were made retroactive to July 25, 1980. See 18 C.F.R. chap. 1, § 271.1104(e)(1) (1983); *Delivery and Compression Allowances Under the Natural Gas Policy Act of 1978*, 48 Fed. Reg. 44495, 44504 (Sept. 27, 1983).

300. Tr. 1534. The Government's other compression expert, Mr. Martin, testified that he had *no* opinion

as to the typical cost of compression in 1975. Tr. 2647-48.

301. The variance in the compression cost per stage pertains to the cost of fuel, which is a function of the sale price of the gas, a factor that varies from transaction to transaction. Given that the sale prices in the transactions in issue range from roughly $0.12/Mcf to $2.10/Mcf, and our finding that a typical 75-hp field compressor consumes 0.0180 Mcf of fuel for each Mcf of gas compressed, fuel costs range from approximately $0.0022/Mcf, in the case of low-priced transactions, to $0.0378/Mcf for high-priced transactions. Upon adding such fuel costs to the non-fuel compression cost determined herein ($0.0482/Mcf), *supra*, we derive a total cost of compression ranging from approximately $0.0504 to $0.0860 per Mcf per stage.

302. See also *Field Handling of Natural Gas*, *supra*, at 59-71; DX 2 at 12-13, SubX I. As noted above, dehydration differs from field separation, which removes *liquid* water.

303. Excessive water vapor content can cause corrosion of purchaser's pipeline, or lead to the formation therein of hydrates, icelike crystals that can block the flow of gas in the pipeline. Tr. 331; *Field Handling of Natural Gas*, *supra*, at 52, 59; DX 2 at 12. See also Exxon I, 33 Fed. Cl. at 257 & n.4 (similar finding as to 1974).

304. Tr. 948-49, 957; PX 6 at 20. Testifying for the Government, Mr. Martin conceded that the absence of a maximum water vapor content specification in a gas purchase contract supports the conclusion that the producer did not, in fact, dehydrate its gas before sale. Tr. 1950-51.

305. The 140 transactions involving dehydration before sale are shown in Appendix A, *infra*, as having an entry in the column for dehydration deductions from the sale price of the gas.

306. Tr. 2648; DX 1 at 16.

307. Tr. 1539 (Nicol), 2413 (Platt); *Field Handling of Natural Gas*, *supra*, at 59, 61. As Mr. Nicol explained, triethylene glycol has a stronger affinity for water vapor than natural gas does, and forms a chemical bond with water vapor. Tr. 1539.

308. Compare *Field Handling of Natural Gas*, *supra*, at 61-65 (discussion and diagrams of glycol dehydrators), with id. at 78-95 (discussion and diagrams of reciprocating compressors), reproduced at PX 1, SubX 9. Whereas a reciprocating compressor is powered by an internal combustion engine, and requires an intricate assemblage of intake and outlet valves to contain and direct the gas flow, the only significant moving part in a glycol dehydrator is a simple pump, powered by the pressure differential between the absorber and reboiler, that recirculates the glycol through the unit. DX 2, SubX I; Tr. 1541. In addition, an engineering treatise excerpted in Mr. Platt's report notes that glycol dehydrators are "simple to operate and maintain and can be easily automated for unattended operation." Gas Processors Suppliers Association, *Engineering Data Book*, *supra*, at 15-11, reproduced at PX 5, SubX 23, at PL21-00060.

309. *Field Handling of Natural Gas*, *supra*, at 60; DX 2, SubX I; Tr. 2422; PX 5 at 27. This is roughly 1/20 of the fuel consumption of a typical 75-hp reciprocating field compressor, determined herein to be 0.0180 Mcf of fuel usage per Mcf of gas compressed, *supra*, or 18 Mcf of fuel usage per MMcf of gas compressed. Whereas a reciprocating compressor consumes gas fuel in a powerful internal combustion engine, a glycol dehydrator simply burns the gas fuel in an open flame in the reboiler section, at temperatures ranging generally from 350 to 400 degrees Fahrenheit. *Field Handling of Natural Gas*, *supra*, at 61, 64, reproduced at PX 1, SubX 9; Gas Processors Suppliers Association, *Engineering Data Book*, *supra*, at 15-13, reproduced at PX 5, SubX 23, at PL21-00062. Such temperatures can be achieved

in an ordinary household oven, suggesting that glycol dehydration is not an especially fuel-intensive process.

310. By way of comparison, Mr. Platt determined the non-fuel cost of dehydration to be $0.00485/Mcf. Tr. 2410-20; PX 5 at 27, SubX 24.

311. Specifically, we have determined that a typical glycol field dehydrator consumes 900 cf of fuel for each MMcf of gas dehydrated, *supra*, which equates to 0.0009 Mcf per Mcf of gas dehydrated. Given the sale prices observed with respect to the transactions in issue, ranging from roughly $0.12/Mcf to $2.10/Mcf, the cost of fuel ranges from approximately $0.00011/Mcf, in the case of low-priced transactions, to $0.00189/Mcf for high-priced transactions.

312. Although Messrs. Nicol and Martin, for the Government, opined that dehydration costs typically ranged from $0.01 to $0.02 per Mcf in 1975 (Tr. 2647; DX 1 at 17; DX 2 at 12), they submitted no dehydration cost calculations, and cited no authoritative works on the cost of dehydration. Given the foregoing, their opinions are without probative weight.

313. Only 30 of the transactions in the court's RMFP sample were untainted by either compression or dehydration. Thus, 278 transactions were tainted. There is, of course, considerable overlap, *i.e.*, transactions tainted by both compression and dehydration, since 243 transactions were tainted by compression and 140 transactions were tainted by dehydration.

314. See Appendix A, *infra* (tabulation of 308-transaction RMFP sample).

315. As noted above, we had computed a tentative RMFP on the basis of our 308-transaction sample, but without making any adjustments to Mr. Platt's compression and dehydration deductions, in the sum of approximately $0.6944/Mcf. Our adjustments to Mr. Platt's compression and dehydration deductions reduce that tentative RMFP by approximately $0.0108/Mcf and $0.0005/Mcf, respectively, and by $0.0113 in total.

316. As previously noted, the sparse legislative history of § 613A furnishes no authoritative guidance as to the types of contracts that qualify, or fail to qualify, under the fixed contract exception. See Exxon, 40 Fed. Cl. at 79 & n.11, 80 n.12.

317. PX 12o at HLPF0000042. Humble Oil & Refining Company, a predecessor in interest to Exxon, was a party to the original HL&P contract, as well as the original SWEPCO contract, *infra*. Herein, for ease of analysis, we refer to Exxon and its predecessor jointly as "Exxon." At all times relevant to this action, HL&P was an electric utility company, engaged in the business of generating and selling electrical power to residential and industrial customers in the Houston area. PX 12o at HLPF0000001, HLPF0000041-42, HLPF0000085. Similarly, SWEPCO was an electric utility company doing business in the East Texas area. PX 12b at SWEF0000079-80.

318. PX 12o at HLPF0000050.

319. Under "Option No. 1," *supra*, the price for 1975 (and succeeding years) would be established by binding arbitration. PX 12o at HLPF0000051, HLPF0000056-58. Under "Option No. 2," such prices would be set in accordance with a complex formula keyed to Exxon's "Field Price." PX 12o at HLPF0000052-56. We shall have more to say, in due course, about the Exxon Field Price. For now, it suffices to note that neither Option 1 nor Option 2, *supra*, ever went into effect because, as discussed below, Exxon and HL&P reached an agreement in mid-1974 concerning the contract pricing for the years 1975-1984.

320. PX 12o at HLPF0000001-07. As originally executed, the HL&P contract provided that Exxon would supply 49% of HL&P's fuel requirements during the years 1965-1984, estimated therein at approximately 2,300 Bcf. PX 12o at HLPF0000041-42, HLPF0000081. Of the foregoing estimated fuel requirements, roughly 1,400 Bcf related to the years 1975-1984. PX 12o at HLPF0000081. The May 29, 1974 contract amendment increased Exxon's future gas supply commitments under the contract to 3,200 Bcf. PX 12o at HLPF0000002.

321. PX 12o at HLPF0000008.

322. Amounts "paid under the provisions of Sections A and B of . . . Article III," *supra*, related to the stated contract price, *i.e.*, 26¢ per Mcf for 1975. PX 12o at HLPF000008-11. Amounts "paid pursuant to the provisions of Article IV" related to HL&P's obligation to reimburse Exxon for certain taxes imposed upon the subject gas -- principally, severance taxes imposed by the State of Texas -- to the extent such taxes were imposed at rates exceeding those in effect at the time the contract was made. PX 12o at HLPF0000013-14; Tr. 1259.

323. PX 12b at SWEF0000017-18.

324. PX 12b at SWEF0000007.

325. The first paragraph above, calling for a 0.75¢ per MMBtu price increase, effective January 1, 1974, *supra*, is not in dispute. This provision simply increased the contract price otherwise applicable during 1975, from a fixed 25¢ per MMBtu, as previously agreed by Exxon and SWEPCO on October 29, 1971, to a fixed 25.75¢ per MMBtu. Because this 0.75¢/MMBtu price increase took effect prior to February 1, 1975, the cut-off date for the fixed contract exception under § 613A(b)(2)(A), it does not disqualify the SWEPCO contract from "fixed contract" status.

326. Tr. 1253-58, 1294-95; PX 8 at 7-9. Here, we refer to "fixed-price" contracts in the commercial sense, not in connection with the definition of a "fixed contract" under § 613A(b)(2)(A). By "fixed-price," we do not mean that the contract price was fixed at a single, unvarying dollar amount throughout the entire term of the contract. Rather, we mean that when the contract was made, the contract fixed the price of the gas in future contract years, including price escalations, *in advance*, as opposed to leaving the price in such future years to be negotiated at that time, or allowing future prices to "float" by means of a pricing formula tied to current market prices. For example, as noted above, the HL&P contract initially fixed the price at 20.5¢/MMBtu for the first six contract years (1965-1970), and at 21¢/MMBtu for the succeeding four contract years (1971-1974). PX 12o at HLPF0000050. Thus, from a commercial perspective, the 21¢/MMBtu price for the latter four years was "fixed," irrespective of the fact that said price represented a half-cent increase over the initial contract price.

327. Tr. 1256-58, 1294-95; PX 8 at 9. Typically, the right to exploit a natural gas deposit is conveyed by a mineral lease, pursuant to which the producer (*i.e.*, Exxon) pays royalties to compensate the owners of such mineral rights. See Exxon I, 33 Fed. Cl. at 263 n.14 ("A royalty interest is a right to oil and gas in place that entitles its owner to a specified fraction, in kind or in value, of the total production from the property, free of expense of development and operation."). In Exxon's case, such royalties were payable to the lessors of the oil and gas leases from which Exxon produced natural gas, at rates typically set at either one-sixth or one-eighth of the market value of such gas. Tr. 1256, 1287-88.

328. The Government concedes, on the other hand, that the disputed price adjustment clause in the HL&P contract was, in fact, an ERR clause.

329. The Supreme Court concisely summarized this peculiar aspect of the percentage depletion

allowance, as follows:

Congress has allowed holders of economic interests in mineral deposits, including oil and gas wells, to deduct from their taxable income the larger of two depletion allowances: cost or percentage. Under cost depletion, taxpayers amortize the *cost* of their wells over their total productive lives. Under percentage depletion, taxpayers deduct a statutorily specified percentage of the "gross income" generated from the property, *irrespective of the actual costs incurred*.

Engle, 464 U.S. at 208-09 (emphasis added).

330. In the case at bar, Exxon lays claim to a notably generous subsidy. Specifically, in its 1975 corporate income tax return, as originally filed, Exxon claimed $82,059,252 of depletion deductions, of which the vast majority was percentage depletion, in connection with the 369 gas properties in issue. Had Exxon made that depletion computation exclusively under the cost depletion method, which is limited to the taxpayer's out-of-pocket investment in each gas property, its depletion deductions for those same 369 properties would have been a minuscule $133,640. PX 22 at 23, ¶¶ 8-9. In other words, Exxon's 1975 tax return claimed a "subsidy" of $81,925,612, in the form of percentage depletion deductions.

331. Tr. 1290-91, 1306-07; PX 12o at HLPF0000053. The Exxon Field Price is analogous, but not identical, to the RMFP under Treas. Reg. § 1.613-3(a). Both figures are computed as volume-weighted average prices. See Exxon I, 88 F.3d at 979 & n.9; 33 Fed. Cl. at 263-64. However, a major distinction between the RMFP and Exxon's Field Price is that the former is based exclusively upon sales of raw gas, whereas the latter is based, in part, upon sales of processed gas. See Exxon I, 33 Fed. Cl. at 264 n.17 (similar finding as to 1974).

332. Tr. 1328. Mr. Whitcomb testified that Exxon's royalty payments for January of 1975 were based upon a Field Price of approximately 50¢ per Mcf, and that for the entire 1975 year, the Field Price on which Exxon calculated its royalty payments averaged roughly 70¢ per Mcf. Tr. 1293-94. See also PX 1 (Pohler report, noting that 1975 average Field Price was approximately 71¢ per Mcf). By comparison, Exxon's average Field Price for all of 1974 was 30¢ per Mcf. Exxon I, 33 Fed. Cl. at 263.

333. Curiously, the Government also urges that royalty cost pass-through arrangements, *i.e.*, the ERR clause in the HL&P contract, are invalid on the ground that "the statute is only concerned with whether the *price* for the natural gas sold under a contract can be adjusted, not whether the income earned on the contract changes." Def. Brf. at 12 (emphasis in original). Stated differently, defendant believes that for purposes of determining whether a contract is "fixed," the court must inquire whether the gas producer's *gross* revenue per unit of gas sold is fixed, not whether the producer's *net* revenue, after royalty costs, is fixed. The problem with the Government's argument is that it implicitly repudiates the regulatory definition of a "fixed contract" in Treas. Reg. § 1.613A-7(d), which expressly permits cost pass-through arrangements that are wholly unrelated to the producer's increased income tax liabilities, as being contrary to the statutory definition of a "fixed contract" in § 613A(b)(2)(A). However, as we have previously observed, the depletion regulations, Treas. Reg. § 1.613A-7(d) included, are legislative in effect. See Exxon, 40 Fed. Cl. at 84-85. Therefore, inasmuch as Treas. Reg. § 1.613A-7 gives a reasonable construction to the statutory definition of a "fixed contract" under § 613A(b)(2)(A), we are constrained to view said Treasury Regulation as a lawful exercise of the Secretary's delegated authority to promulgate rules governing the percentage depletion allowance. See Portland Cement, 450 U.S. at 165, 169.

334. PX 12o at HLPFI000081-105; PX 9q at EGSST000001-000025.

335. PX 12o at HLPFI000082.

336. PX 12o at HLPFI000084.

337. PX 12o at HLPFI000105.

338. PX 12o at HLPFI000081-82 (January 1975); PX 12o at HLPFI000105 (October 1975). Also included in Exxon's January 1975 ERR invoice was the sum of $11,977, representing a correction to the ERR billing for December of 1974. PX 12o at HLPFI000080-82.

339. For example, in January of 1975, Exxon billed HL&P the sum of $4,394,235 for 16,531,053 Mcf of gas, having a heating value of 16,846,246 MMBtu. PX 9q at EGSST000001. This works out to a weighted average price of approximately $0.2658 per Mcf, or $0.2608 per MMBtu, before the ERR billing. The difference between the $0.2608 per MMBtu actually billed in January of 1975, and the $0.26 per MMBtu contract price specified in the May 29, 1974 amendment to the HL&P contract (PX 12o at HLPF0000008), was attributable to certain severance taxes incurred by Exxon on the gas in question, for which it was entitled to reimbursement from HL&P. PX 12o at HLPF0000013-14. Such severance tax reimbursements are expressly permitted by Treas. Reg. § 1.613A-7(c) and (d), and are not in dispute here. Upon adding the January 1975 ERR billing of $623,022, to the $4,394,235 that was billed at the regular contract price of $0.26/MMBtu (plus severance tax reimbursement), we find that $5,017,257 was the total amount billed by Exxon to HL&P in January of 1975. Dividing the $5,017,257 total sale price, by the quantity of gas sold (16,531,053 Mcf or 16,846,246 MMBtu), we derive the actual total sale price of $0.3035 per Mcf, or $0.2978 per MMBtu.

340. Based upon our examination of the invoices that Exxon submitted to HL&P during 1975 (PX 12o at HLPFI000001-78), and the underlying Exxon accounting records (PX 9q), the court concludes that no price increases occurred under the Additional Gas clause, *supra*, because Exxon evidently sold no such "additional gas" to HL&P during 1975.

341. Tr. 1351. See generally Tr. 1342-62 (Whitcomb inability to explain origin of numerical data in ERR workpapers).

342. Tr. 1416-18; PX 7 at SubX 10-11, Appendix 2. As noted above, the court herein defers any decision as to the GIFP issue, pending the parties' efforts to resolve said issue by stipulation.

343. Employed as a gas accountant by Exxon since 1973, Mr. Watson was involved in the implementation and administration, during 1975 and thereafter, of the accounting procedures and systems that Exxon used to make its percentage depletion calculations under the fixed contract exception. Tr. 1368-70. Although Mr. Watson testified generally that Exxon's gas accounting department performed the ERR calculations for the HL&P contract, he failed to specifically address the 1975 ERR workpapers that are in evidence. Tr. 1452-54.

344. Tr. 1284. Mr. Whitcomb admitted that he had never audited the accuracy of Exxon's ERR calculations, during the time that he was responsible for administering the HL&P contract, but testified in generalized terms, without any elaboration, that he recalled HL&P doing so. Tr. 1363. Even assuming that such bland testimony is entitled to any probative weight, the record fails to disclose whether HL&P audited Exxon's ERR calculations for the year 1975, nor the outcome of any such audit, if one occurred.

345. It is for this reason, of course, that Exxon's alleged retroactive royalty costs need not be subtracted from its 1975 "gross income from the property" (GIFP), with respect to the 369 Exxon properties in issue. See § 613(a) (GIFP must be reduced by pertinent royalty costs). Therefore, even assuming that the alleged retroactive royalty costs were properly taken into account for purposes of determining whether the gas that Exxon sold under the HL&P contract in 1975 was eligible for percentage depletion,

consistency of treatment would require that said retroactive royalties also be taken into account as a subtraction from Exxon's 1975 GIFP.

346. In addition, as in the case of the HL&P contract, *supra*, Exxon failed to present any testimony from present or former SWEPCO employees having personal knowledge of the November 26, 1973 amendment of the SWEPCO contract, and the negotiations precedent thereto, for the purpose of corroborating Mr. Whitcomb's testimony. We note also that Exxon's own accounting records expressly designate a portion of Exxon's 1975 revenues under the HL&P contract as purported excess royalty reimbursements, but designate none of Exxon's 1975 revenues under the SWEPCO contract in like manner. See, e.g., PX 9q at EGSST000002 (Exxon Gas System "Sales and Transfers" report for the month of January 1975).

347. Tr. 1317-23; PX 12b at SWEFI000025 (Exxon workpaper calculating said price).

348. PX 12b at SWEFI000001-24 (invoices); PX 9q *passim* (Exxon 1975 "Sales and Transfers" report tabulating volume (Mcf), heating value (MMBtu), and revenues for gas sold to customers served by Exxon Gas System, and corroborating invoices to SWEPCO).