IN THE SUPREME COURT OF ALABAMA

EXXON MOBIL CORPORATION,	)	
	)	
Appellant,	)	
	)	**SUPREME COURT**
vs.	)	**NO. 1031167**
	)	
ALABAMA DEPARTMENT OF CONSERVATION AND NATURAL RESOURCES, et al.,	)	
	)	
Appellees.	)	

BRIEF OF APPELLANT EXXON MOBIL CORPORATION

ON APPEAL FROM THE 15th JUDICIAL CIRCUIT
(MONTGOMERY COUNTY) CV 99-2368

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ORAL ARGUMENT REQUESTED

STATEMENT REGARDING ORAL ARGUMENT

Exxon Mobil Corporation (Exxon) appeals from a judgment awarding the State of Alabama over $100 million in contract damages and interest and $3.5 billion in punitive damages. The record is extensive,[1] the matter is obviously of great public as well as private interest, and the issues are in several respects novel and complex. The issues include:

1. The legal sufficiency of the State's fraud evidence, a straightforward inquiry that Exxon believes is controlled by *Hunt Petroleum Corp. v. State*, 2004 WL 924138 (Ala. Apr. 30, 2004).

2. The proper legal construction, on multiple issues, of the State's unique and complicated offshore oil and gas lease form, which this Court has never before construed.

3. The legal availability of punitive damages to the State in this setting and the constitutionality of the unprecedented $3.5 billion award.

Exxon respectfully submits that oral argument will aid this Court's consideration of these important issues.

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[1] The clerk's record contains over 6,200 pages, the reporter's transcript over 3,800 pages, and the trial exhibits over 13,000 pages. Post-trial *Hammond* hearing transcripts and exhibits also contain thousands of pages.

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STATEMENT OF JURISDICTION

The Court has jurisdiction under *Ala. Const.* § 6.02(c), Amendment 328, and *Ala. Code* § 12-2-7(1). Exxon appeals from a judgment entered on November 19, 2003 as final under *Ala.R.Civ.P.* 54(b), a final judgment entered on December 5, 2003, and a March 29, 2004 order denying Exxon's post-trial motions and declining to reduce the punitive damages below $3.5 billion. C1406, 1424, 2274.[2] Exxon filed timely post-

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[2] Throughout this brief, Exxon cites the record as follows:

• Clerk's record on remand from prior appeal (No. 1001053)	C[page]
• Clerk's record before prior appeal	CA[page]
• Clerk's record material under seal	C*[description]
• Reporter's transcript of retrial	R[page:line]
• Reporter's transcript of first trial (where pertinent)	RA[vol/page/line]
• Reporter's transcript of second *Hammond* hearing	HR[page:line]
• Reporter's transcript of first *Hammond* hearing (incorporated in second *Hammond* hearing, C1538)	HRA[vol/page/line]
• Reporter's transcript of 3/25/04 post-*Hammond* telephone conference	R(3/25/04) at [page:line]
• Trial and *Hammond* hearing exhibits	PX, DX, HPX or HDX by number and page

Note: for multi-page exhibits lacking consecutive page numbers, Exxon cites pages sequentially with asterisks (*e.g.*, DX1096 at *8-*10) and gives identifying bates numbers where available. As it did in the prior appeal, Exxon will provide a CD with links to the cited pages.

trial motions on December 15, 2003. C1429. On March 8, 2004 and again on March 12, 2004, pursuant to *Ala.R.Civ.P.* 59.1, the parties consented on the record to extend the trial court's 90-day period to rule on the motions. C1769, 2128. The trial court disposed of all post-trial motions on March 29, 2004, and Exxon filed a timely notice of appeal on April 27, 2004. C2274, 2339.

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STATEMENT OF THE CASE

I. NATURE OF THE CASE

Exxon Mobil Corporation, formerly Exxon Corporation (Exxon), appeals the judgment below awarding the State of Alabama $102 million in contract damages and interest and ***$3.5 billion*** in punitive damages for alleged "fraudulent" underpayment of royalties on gas leases in Mobile Bay.

Like the State's lawsuits against other Mobile Bay producers, this case is a contract dispute masquerading as a fraud action. The State imposed on the producers a new and unique lease form which no appellate court has ever construed. As often occurs with new forms, interpretive disputes arose. To obtain leverage in those contract disputes, the State has pursued a strategy of suing every producer for fraud and exhorting Alabama jurors to award huge punitive damages against the out-of-state producers.

In *Hunt Petroleum Corp. v. State*, No. 1011762, 2004 WL 924138 (Ala. Apr. 30, 2004), this Court rejected that strategy. Applying the rule that "[w]ithout reliance there can be no fraud," the Court held that the State, which audited every producer, could not show that it relied on any alleged misrepresentation, express or implied, about

the accuracy of the royalty payments or their conformance with the State's lease interpretation. *Id.* at *6-*8. And without fraud, there could be no punitive damages. *Id.*

Hunt controls here. Indeed, even more than in *Hunt*, the undisputed evidence establishes that the State never relied on any alleged misstatement or omission by Exxon to determine what was due. When in early 1995 Exxon candidly disclosed the basis for its royalty computations, the State responded that all payments were subject to audit. Then it did as it had always planned - it audited Exxon applying its own lease interpretation and sent Exxon a bill for its full claim. The evidence negates not only reliance but every other element of fraud, including misrepresentation, concealment or suppression, and intent.

This appeal also tenders to this Court the underlying lease interpretation issues. Although the din of the State's fraud rhetoric has prevented a fair hearing of those issues thus far, the record developed below provides a sufficient basis for this Court, applying relevant case authorities and rules of construction, to construe the lease form as a matter of law. There are seven disputed lease interpretation questions, each associated with a

severable portion of the $102 million in contract damages and interest. Some are simple and some are complex, but all, Exxon submits, should be resolved in Exxon's favor based on the undisputed ***material*** facts established at trial. If the Court agrees in whole or in part, the contract damages must be reduced accordingly. This Court's resolution of these issues will also determine how to compute royalties under the leases going forward.

Finally, should the fraud claim somehow survive, Exxon challenges both the propriety and size of the $3.5 billion punitive award. Alabama jurors, inherently self-interested, may not award Alabama (and themselves) huge punitive damages without violating both Alabama law and due process. The sheer size of the award - $11.8 billion before remittitur - demonstrates the constitutional violation. And as reduced by the trial court to $3.5 billion, the award is still grossly excessive, at least ***149 times*** the fraction of the contract damages that the jury, by special verdict, attributed to Exxon's alleged fraud. The award is arbitrary and unconstitutional, and this Court must therefore reverse it altogether or, at minimum, drastically reduce it.

II. COURSE OF PROCEEDINGS AND DISPOSITION BELOW

This case began on July 28, 1999, when Exxon sued the Department of Conservation and Natural Resources (DCNR) to obtain judicial resolution of a longstanding dispute over how to calculate royalties under offshore gas leases. CA1. A month later, on August 24, 1999, the State counterclaimed for breach of contract and fraud, alleging Exxon had underpaid royalties since production began in October 1993. CA8. Forty-two days after filing its counterclaim, the State added a demand for punitive damages. CA851. Over Exxon's objection, the trial court (McCooey, J.) realigned the parties to allow the State to be plaintiff. CA1664. The trial court denied the parties' summary judgment motions without opinion (CA891, 962), stating that "there isn't anything clear about that lease." RA21/150:8-9.

The dispute proceeded to trial. On December 19, 2000, the jury awarded the State $60,194,174 in additional royalties for the 75-month period October 1993 through December 1999 - the full amount requested - plus a 12% statutory interest penalty of $27,498,521 and unprecedented punitive damages of $3.42 ***billion***. CA1987-88; HDX183a. After a *Hammond* hearing, the trial court, in an order

adopting the State's proposed order almost verbatim, refused to reduce any of the damages and denied all of Exxon's post trial motions. *Compare* CA3762 *with* CA2759.

Exxon appealed. On December 20, 2002, this Court reversed and remanded, holding that the trial judge had impermissibly admitted into evidence a confidential legal opinion prepared by Exxon's in-house attorney. *Exxon Corp. v. DCNR*, 859 So. 2d 1096, 1108 (Ala. 2002). The Court denied the State's petition for rehearing, and the trial court set the case for retrial in October 2003.

The retrial lasted 14 days and went to the jury on November 13, 2003.[3] The next day, the jury awarded the State $63,592,647 (before interest) in additional royalties for the 111-month period October 1993 through December 2002. R3810:11-20.[4] This was again the full amount requested, but only about 70% of the average monthly damages awarded in the first trial (which covered only the first 75 months). The difference reflected the State's

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[3] Exxon moved, unsuccessfully, for judgment as a matter of law at the conclusion of the State's evidence (R25219:24-2562:22) and at the conclusion of all the evidence. C1364; R3402:20-3426:18, 3544:14-3546:6.

[4] The jury's special verdict included a separate line item for each category of claimed additional royalties. C1418.

abandonment of indefensibly inflated damage claims it had asserted in Exxon's prior appeal.[5]

The verdict form also required the jury to specify any portion of the contract damages it deemed attributable to fraud. Adopting the State's closing argument (R3599:25-3600:24), the jury found this amount to be $23,449,186, the royalties claimed by the State through February 1997, the month in which the State completed its first audit of Exxon's payments. R3810:21-23; DX1285B.

Although the contract damages were 30% lower than in the first trial, and the "fraud" damages only a fraction of that amount, the punitive damages were incomparably higher. With the earlier $3.42 billion punitive award obviously in mind, the State told the jury that any verdict less than $4 billion would be a "clear victory" for Exxon. R3740:18-23. Asserting that Exxon stood to gain $930 million if it underpaid royalties for the life of the Mobile Bay fields, all three of the State's lawyers urged the jury to impose

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[5] These included unfounded claims that Exxon sold gas for less than the best price realizable, based royalties on gas prices lower than those actually received, and underpaid royalties on a tract ***not*** governed by the disputed lease form. *See* Brief of Appellant Exxon Corporation, Supreme Court No. 1001053 (filed 9/24/01) at 110-13.

punitive damages of ten times that amount, or $9.3 billion. R3602:1-3604:13, 3747:18-3748:9, 3754:18-3755:10.

The jury obliged, and then some, awarding the astonishing sum of $11.8 billion - over $2,500 for every man, woman and child in Alabama and $2.5 ***billion*** more than the State had urged. R3810:23-24; HDX291. On November 19, 2003, the trial court added the 12% statutory interest penalty of $39,235,154 to the $63,592,647 in contract damages and entered judgment against Exxon for the full verdict amount of $11,902,827,801. C1406.

On December 1, 2003, Exxon requested a hearing in its declaratory judgment action to obtain guidance on how to apply the jury's verdict to royalty computations going forward. C1408. On December 5, 2003, the trial court denied this request and entered the State's proposed declaratory judgment directing Exxon, without any guidance, to "pay ... according to the plain, unambiguous language of the leases as reflected in the jury's verdict." C1424.

Exxon filed comprehensive post-trial motions and requested a *Hammond* hearing to consider a reduction of the punitive damages. C1429, 1475, 1478, 1528, 1538, 1583, 1608, 1631, 2099. After a two-day hearing on March 11-12,

2004, the trial judge advised the parties that she intended to reduce the punitive damages to $3.5 billion and deny all other motions. R(3/25/04) at 9:7-20:1. The judge said she continued to believe that the $3.42 billion award she had previously approved had been "totally appropriate," but would set the new amount "a little higher" - actually ***$80 million*** higher - "because we have had a second trial." *Id.* 15:17-16:4.

The State submitted a lengthy and argumentative proposed order, to which Exxon filed detailed substantive objections. C2183, 2252. As before, the trial court adopted and entered the State-drafted order almost verbatim. *Compare* C2274 *with* C2183. This appeal followed.

STATEMENT OF THE ISSUES

1. Under *Hunt* and this Court's other precedents, was the evidence legally insufficient to support a fraud verdict, and therefore to allow any punitive damages?

2. As a matter of law, must the Mobile Bay leases be construed consistently with Exxon's contract positions on cost netting, fuel gas, gas measurement, sulfur, electricity, condensate, and/or payout, and the contract damages and interest reduced accordingly?

3. Do *Ala. Code* § 6-11-21(*1*) and/or the Due Process Clauses of the 14th Amendment of the U.S. Constitution and Article I, § 13 of the Alabama Constitution bar recovery of punitive damages by the State?

4. Does the $3.5 billion punitive award exceed any punishment permissible under (1) *Ala. Code* § 6-11-21 and this Court's cases, (2) the Due Process Clause of the 14th Amendment of the U.S. Constitution and Article I, § 13 of the Alabama Constitution, and/or (3) the Excessive Fines Clauses of the 8th Amendment of U.S. Constitution and Article I, § 15 of the Alabama Constitution?

STATEMENT OF THE FACTS

I. FACTUAL BACKGROUND: EXXON'S MOBILE BAY PROJECT

In 1979, Mobil Oil Company (then separate from Exxon) discovered natural gas in Mobile Bay. R1567:5-22 (Macrory). In the wake of this find, the State put out for competitive bid the rights to explore for and produce oil and gas on designated tracts in State territorial waters. PX110. Exxon successfully bid for 22 of these leases in 1981 and 1984, paying $573.3 million in non-refundable bonuses. PX6-27, 119; R3071:21-3072:20, 3073:13-17 (Hand); R2578:23-2579:1, 2579:10-2580:15 (Kahn).

After eight years of exploratory drilling (costing another $181 million), Exxon determined in 1990 that 10 of the 22 leases contained enough gas to justify the huge investment required to produce them. R3072:3-20 (Hand). Exxon returned the other 12 leases to the State, forfeiting the $212 million in bonuses it had paid for them and the opportunity to recoup more than $90 million it had spent drilling unproductive wells. R2582:9-2583:15 (Kahn); R3072:10-3073:5 (Hand).

Exxon pooled the 10 remaining leases into four "units" corresponding to subsurface natural gas reservoirs and entered into unit agreements with the State specifying how much each lease would share in the pooled production and expenses of the unit. PX1-5; R2607:6-25 (Kahn). To produce and market the gas, Exxon spent over $1.5 billion to build three offshore production platforms, 16 offshore wells, and other facilities. R3073:6-12, 3074:2-5 (Hand).

When it approved this investment in 1990, Exxon projected a net overall profit (on a present value basis) of $250 million. DX733 at 0039312. By December 2002, Exxon had invested over $2.1 billion, of which $298 million

remained unrecovered. R3072:21-3074:15 (Hand); DX1285 at *6 (Borden Report Tab 1, at 2).

Mobile Bay development costs are unusually high because the gas comes from 5-mile deep Norphlet reservoirs that produce so-called "sour" gas, containing predominantly methane but also significant quantities of highly toxic and corrosive hydrogen sulfide (H_2S). DX1096 at *8; R2577:17-24 (Kahn); 1221:16-1222:16, 1225:7-1126:6, 1268:11-18 (Hite). The H_2S must be removed to make the gas "sweet" and thus suitable for transportation by commercial pipelines. R1205:14-26 (Hite); R2588:13-24 (Kahn). While some producers contract with third parties to perform the necessary "sweetening," Exxon decided to build its own Onshore Treating Facility (OTF). R2587:25-2589:10 (Kahn); DX1096 at *8-*10. The OTF, located in Theodore, Alabama, accounts for a substantial portion of Exxon's capital investment in Mobile Bay. R3074:2-5 (Hand).

Production of gas occurs at the offshore wells and platforms. DX1096 at *8; R2595:6-2596:4, 2601:4-15 (Kahn); R1082:3-13 (Condray). The raw wellstream at Mobile Bay includes (besides gas) both salt water and wax-like heavy hydrocarbons known as diamondoids. DX1096 at *8. To

prevent the salt and diamondoids from obstructing flowlines and production equipment, Exxon injects both fresh water (to dissolve the salt) and fresh diesel (to dissolve the diamondoids) into the wells. *Id.* The production stream at the wellhead thus includes a mixture of both commingled raw gas (methane and H_2S) and commingled liquids (water and "spent" diesel with dissolved diamondoids).

This gas/liquid mixture travels by flowline from the wellhead to a production platform where, after passing through a "full wellstream" meter, the raw gas is separated from the liquids and dehydrated. DX1096 at *8; R3069:2-19 (Hand). Each month, Exxon samples and analyzes a portion of the raw gas at separation to determine its chemical composition, and applies a "wet/dry" ratio to estimate the volume of gas included in the full wellstream production of each well. DX1096 at *8; R2716:24-2717:16 (Bolin). When the gas leaves the platform after dehydration, it passes though a "platform exit" meter that measures its volume directly. DX1096 at *9; R2714:19-2715:13 (Bolin).

The gas then travels to the OTF via a 26-mile offshore pipeline network known as the "gathering system." DX1096 at 3; PX278; R1305:16-1306:11 (Hite); R3066:3-12 (Hand).

Upon reaching the OTF, the gas - still sour - passes through additional meters that measure its volume before and after treatment. DX1096 at *10. To make the gas sweet, Exxon subjects it to an expensive chemical wash that removes the H_2S. DX1096 at *8-*10. The sweetened gas, called "residue" gas, is then available at the OTF "tailgate" for sale to customers via local delivery or delivery into one of three interstate pipelines. R927:20-928:10 (Woodbury); R1316:21-1317:2 (Hite).

Exxon sells the sweet residue gas both at the OTF tailgate and at downstream points of sale on the connected pipelines. R927:20-928:10 (Woodbury). If Exxon sells the gas at a downstream point of sale, it charges a higher price to compensate for its cost of transporting the gas from the OTF tailgate to the point of sale. R928:5-10 (Woodbury).

Exxon retains a small portion (less than 2%) of the sweet gas for its own use as "fuel gas" for operations of both the OTF and the offshore platforms. DX1096 at *10; DX1285 at *11 (Borden Report Tab 1 at 7); R1287:1-3, 1299:8-25, 1300:4-17 (Hite). Exxon uses gas, for example, as fuel for electrical generators that power cooling

turbines. R1299:15-20, 1300:4-17, 1336:16-19 (Hite). If Exxon generates more electricity than it needs, it sells the surplus (so-called "co-gen" power) to Alabama Power Company. DX1096 at *11; R2728:14-20 (Bolin).[6]

Exxon uses the H_2S extracted from the sour gas to make molten liquid sulfur. The H_2S is heated to 1400 degrees, the resulting vapors condensed, and any unvaporized residue passed through catalytic converters. R1269:5-15 (Hite); R2630:4-2631:14 (Kahn). Exxon sells the sulfur by the truckload to customers at the OTF. *Id.*; DX1096 at *8-*11.

Exxon also recovers the diamondoid-laden "spent diesel" (called "condensate" for reporting purposes) from the produced liquid stream. This is also sold at the OTF, as "slop oil." DX1096 at *8; R2872:6-2873:3 (Pierce).

A diagram illustrating the flow of gas from wellhead to tailgate is provided in the Appendix at Tab 1.

II. THE DISPUTED LEASE PROVISIONS

Oil and gas leases traditionally require the lessee to bear the costs of exploration and production, but provide

[6] Since late 1999, Exxon has obtained most of its fuel gas from a shallow "Miocene" well on one of the leases. This gas is naturally "sweet" and requires no treatment, leaving almost all of the residue gas from the deep Norphlet wells available for sale to customers. R1300:18-1301:9 (Hite).

for the lessor to bear a share of the ***post***-production costs of gathering and treatment. Exxon achieves this by "cost netting," that is, deducting from gas revenues the post-production costs of gathering the gas from the offshore leases and treating it at the OTF. R3076:11-3095:23 (Hand). The State contends that Exxon must pay royalties on "gross proceeds" without deducting those costs.

As this Court noted in *Hunt*, for the lease provision here in dispute, the issue turns on "the proper point at which the gas should have been valued, that is, the point at which 'gross proceeds' should have been calculated." 2004 WL 924138 at *1. If, as the State contends, the proper point of valuation is the OTF tailgate, deductions would be limited to the costs of transporting gas to downstream points of sale. But if, as Exxon contends, the proper point of valuation is offshore, then gathering and treatment costs should be deductible as well. *Id.*

Oil and gas leases also traditionally do not impose a royalty on gas used as fuel in the development and operation of the lease (R2822:6-13, 2854:9-2855:2 (Pierce); 1459:6-13 (Weaver)), and the parties dispute whether the State lease form imposes such a royalty. The dispute also

concerns some smaller royalty computation issues – the proper treatment of metering variations in measuring gas volumes, the proper treatment of costs associated with sulfur and condensate, and the proper treatment of electricity – as well as the proper application of a one-time "payout" provision that appears in the 1984 leases.

Collectively, these disputes concern only a small fraction of the royalties Exxon actually pays to the State. The State's $63 million underpayment claim through 2002 is less than one-tenth of the $746 million in royalties Exxon paid during the same period, and less than one-twentieth of the $1.31 billion Exxon paid the State in royalties and bonuses. R3074:16-25 (Hand). Likewise, the dispute concerns only a small fraction of Exxon's post-production costs, since Exxon has never sought to deduct any portion of its ***capital*** expenditures on the gathering system and the OTF, and capital expenses make up about 85% of Exxon's post-production costs. R3115:16-3117:6 (Hand).

The State issued the 1981 and 1984 lease forms, without negotiation, as the required basis for bids in the lease sales. PX112; R1849:2-25 (Macrory). The official who drafted the form, Robert Macrory, drew on a hodgepodge of

sources. For the paragraph on royalties, he started with language from a Texas form, incorporated language from a Florida form, and then replaced most of that with language from an obscure ***onshore*** lease form published in the Nebraska Law Review in the 1960s, which he then modified in non-standard fashion on his own. R1612:6-15, 1612:20-1613:10, 1616:19-1617:12; 1618:22-1620:2; 1620:16-1621:8; 1621:19-1622:17; 1625:2-16 (Macrory). The result was a lease whose provisions were unlike any standard form, had never been construed by a court, and were therefore incapable of definitive interpretation on the basis of established legal precedents. R1115:11-1116:12 (Condray); R1506:3-1508:3 (Weaver); R1769:13-1771:19 (Burney); R2791:24-2794:12 (Pierce).

The key royalty language appears in paragraphs 5(a) and 5(b), which read in pertinent part:

> 5. When production of oil, gas or any other liquid or gaseous hydrocarbon mineral from the leased area is obtained, LESSEE agrees to pay ... to LESSOR ... the following royalties:
>
> (a) The value of [X%] of the gross proceeds from all oil, distillate, condensate, gas, natural gasoline or other product covered by this lease, produced and sold from the leased area at the price received therefor or at the best price realizable in the exercise of reasonable diligence, whichever is higher; however, if any

oil or gas is produced from any well drilled, whether or not sold or used off the leased area, LESSEE agrees to pay to LESSOR royalty on the oil or gas produced on the above basis, except that no royalty shall be due for gas produced and flared for well testing purposes.

(b) If gas, of whatever nature or kind, including oil well or casinghead gas and any gasesous substance produced from any well, is used, on or off the leased area, by the LESSEE for purposes (including the manufacture or extraction therefrom of gasoline or other products not covered by the royalty provisions of subparagraph (a) above) other than solely in the development and operation of the leased area as provided herein, LESSEE shall pay [X%] of the net amount realized by LESSEE or affiliate from the sale or disposition of the manufactured or extracted products and [X%] of the best price realizable in the exercise of reasonable diligence for all gas used and not sold. On all residue gas sold by LESSEE or affiliate after manufacture or extraction of products, royalty shall be paid under subparagraph (a) in addition to the royalty on manufactured or extracted products.... The phrase "net amount realized" shall be arrived at by establishing the gross sales value of the manufactured or extracted products realized by LESSEE or affiliate and deducting therefrom the reasonable direct costs of manufacture and transportation from the leased area incurred by LESSEE or affiliate; provided (though not to be construed as all inclusive) amortization of pipelines, processing plants, or other facilities owned entirely or in part by LESSEE or affiliate and rate of return thereon are specifically excluded as deductible items of cost.

PX50 (1981 lease form reproduced in Appendix at Tab 2);

PX6-27 (1981 and 1984 leases executed by Exxon).

The "payout" clause, which allows a lower royalty rate pending recovery of specified development costs, provides:

> [T]he word "payout" shall mean "the point in time when the LESSEE has recovered from production, after deduction of state royalty, severance and production taxes, the direct expenses incurred in actually drilling wells on the leased area beginning, for each well, with the spud date and ending on the date each well is ready to be put into production." The cost of pipelines and treating facilities are expressly excluded as recoverable expense items.

PX13-27 (1984 leases, ¶29(1)).

III. EXXON'S LEASE INTERPRETATION

Exxon signed the leases in 1981 and 1984 but did not owe royalties until after production began in October 1993. R1000:24-1001:3 (Condray). Exxon had, of course, considered the interpretation of the lease form before that point. A workpaper from Exxon's 1990 project funding analysis includes a list of potential cost netting items Exxon had classified as "allowed" (on-lease fuel and non-capital costs of sulfur manufacture) and "not allowed" (production costs through separation), along with a longer list of potentially deductible categories labeled "will attempt." DX733 at 0039335.

The "will attempt" list includes the principal categories still in dispute (non-capital costs of gathering

and treatment and treating facility fuel), as well as other larger items that Exxon ultimately decided not to pursue. At the time of the 1990 funding decision, however, Exxon did not need to resolve its position on those items because its "base case" funding analysis forecast that the project would be profitable even if Exxon pursued ***none*** of the "will attempt" items. DX733 at 0039333 (base case assumes no gas cost netting), 0039312-14 (base case present value is $250 million); R2627:21-24 (Kahn).[7]

The actual decision on how to pay royalties came to Exxon management in late 1993 as part of a broader review of not only State royalty issues, but also State severance tax and federal royalty issues.[8] PX182; R1104:11-1105:12, 20-24 (Condray). On State royalty, the briefing package outlined a series of lease interpretation options that, if adopted in their entirety, would have reduced the coming

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[7] The State marked the "no cost netting" assumption as a one-page exhibit and argued that it shows Exxon "knew" the lease allowed no deductions. PX179. No such inference is reasonable, however, when the document is considered in the context of the 700-page funding support book from which the State plucked it. *See* DX733 at 0039333-36.

[8] The Mobile Bay project includes unitized production from federal leases located three miles offshore, which account for about 14.75% of production. HR210:18-211:16 (Borden).

year's projected $40 million potential royalty obligation by an estimated $19.4 million. PX182 at 0045770.

Nearly all ($17.5 million) of these potential savings turned on two issues - the proper point of gas valuation and the deductibility of capital expenditures. *Id.* As the briefing package summarized, the lease language assessing royalty on "gross proceeds," standing alone, implied intent to disallow cost netting. *Id.* at 0045769. But the language assessing royalty only on gas "sold from the leased area" implied a valuation point on the offshore lease, which normally would "allow some deductions" if construed like standard language imposing royalty on gas valued "at the well." *Id.*[9]

The briefing package indicated that no Alabama case had construed the provision and that Alabama's regulatory staff and processes were "inexperienced," but also noted that the State was already auditing Shell, which had opted not to pursue gas cost netting deductions. *Id.* at 0045769-70. Thus, Exxon had "no doubt" that the State would challenge

[9] As discussed *infra* (pp. 74-76), leases imposing royalty on gas valued at the well require cost netting to determine the wellhead value of gas transported, treated and sold off the leased premises. *See also Hunt*, 2004 WL 924138 at *1 (question is ***where*** "gross proceeds" should be calculated).

such deductions if Exxon took them. R1049:22-1050:3, 1146:15-1148:5 (Condray). As the briefing package indicated, the "State [was] expected to audit [Exxon] within one year of first production" (PX182 at 457670), and no auditor would miss that Exxon computed royalties differently from Shell under the same lease form. *Id.* at 0045766 ("[c]ompetitor precedents may affect Exxon's chances of success with alternatives").

Exxon's management ultimately approved a narrow cost netting approach it believed consistent with staff's recommendation that it "be fairly aggressive (given our lease terms) and pursue all cost netting items with a 25% or greater chance of success." *Id.* at 0045765; R1003:24-1005:1 (Condray). Management ***rejected*** the lion's share of the $17.5 million in gas cost netting deductions outlined in the briefing package. R1144:21-1145:2 (Condray).

Management declined to approve deductions for flowlines used to transport the raw wellstream from the offshore wells to the offshore platforms, or for post-production operations on the platforms themselves (*i.e.*, dehydration). R1143:25-1144:20 (Condray); PX182 at 0045770. That interpretation would have saved $8 million (*id.*), but would

have read the lease as requiring the gas to be valued as if sales were made ***literally*** "at the wellhead" rather than "from the leased area" as provided in ¶5(a).

Instead, management chose to interpret paragraph 5(a) as requiring "gas valuation at the platform." *Id.* Under that interpretation, Exxon deducted from the royalty base its post-production costs of (1) transporting the gas ***away*** from the leased area (via the gathering system) and (2) treating the gas at the OTF to make it suitable for transportation and sale via commercial pipelines. *Id.* Given language in ¶5(b) expressly forbidding the deduction of amortized capital expenditures, however, management rejected the option of netting the ***capital*** costs of the gathering system and the OTF. R1141:22-1143:13 (Condray). Although this would have saved another $8.4 million, management chose to limit the deduction to ***non***-capital expenses of gathering and treatment, estimated to produce royalty savings of $1.1 million. PX182 at 0045770.

On the remaining State royalty items, Exxon adopted interpretations estimated to produce combined royalty savings of $1.9 million. PX182 at 0045770; R1129:1-1141:21 (Condray). The briefing package told management that Shell

did not pay royalties on platform fuel and that the "State [is] not expected to object." PX182 at 0045770. This position comported with the straightforward language of ¶5(b) exempting from royalty "gas ... used, on or off the leased area, ... solely in the development and operation of the leased area as provided herein." As noted, Exxon had thought the on-lease fuel exemption clear when it reviewed the lease terms several years earlier. DX733 at 39335.

The briefing package noted that the State was "expected to take exception" to Shell's similar decision not to pay royalty on treating facility fuel. PX182 at 0045770. But Exxon construed such use as within the exemption for fuel "used ... off the leased area ... in the development and operation of the leased area ...." Alternatively, if fuel used at the OTF were not royalty free, it would qualify under the cost-netting analysis outlined above as a deductible post-production cost of gas treatment, to the same economic effect. DX1248.

The briefing package further advised that it was the "State and Shell's position" that non-capital costs of manufacturing sulfur from H_2S were properly deductible up to the sales value of the sulfur. PX182 at 0045770. This

also comported with Exxon's longstanding reading of ¶5(b) as allowing such deductions when the lessee manufactures a product from "gas, of whatever nature or kind" - here otherwise deadly and valueless H_2S - "produced from any well." *See* DX733 at 39335.

Finally, the briefing package advised management that Mobil, which had begun production earlier under the pre-1981 lease form, was paying royalty on "slop oil" sales only when the sales price exceeded the costs of the diesel it purchased to inject into the wells. PX182 at 45770. Exxon deemed this treatment also suitable under the 1981 lease form, because the dissolved diamondoids that came up with the produced liquids otherwise added no value to the injected diesel and could not be sold separately. DX1248; *see also* R2874:1-24 (Pierce); 3123:16-21 (Hand); 3214:4-7 (Griggs).

Exxon did not anticipate in 1993 that the State would claim, as it did in its first audit, that electricity should bear royalty as a "manufactured product" merely because fuel gas powers the generators. Exxon's consistent position has been that electricity is not a constituent product of any hydrocarbon covered by the lease and is not

manufactured "from" gas (as, for example, sulfur is manufactured "from" H_2S) in the sense that the lease requires. *Id.*; *see* ¶5(b) (royalty due where lessee uses gas for "manufacture or extraction ***therefrom*** of gasoline or other products").[10] Exxon does, however, pay royalty on the underlying fuel gas (reported as "co-gen" fuel) consumed to generate electricity that Exxon ends up selling as surplus not needed to develop and operate the leases. DX1248.

The 1993 management briefing package also outlined, in a separate section, two "payout" clause issues having potential to produce estimated "one time" royalty savings of up to $11 million. PX182 at 0045765, 0045773-74. The payout clause, as noted, authorized Exxon to pay royalties under the 1984 leases at a lower rate pending recovery of "direct expenses incurred in actually drilling wells on the leased area beginning, for each well, with the spud date and ending on the date each well is ready to be put into production." As resolved by management, the two issues had an estimated value of $7.9 million. *Id.* at 0045774.

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[10] Throughout this brief, emphasis in quotations (bold italics) is supplied unless otherwise indicated.

The principal issue concerned the allocation of recoverable expenses to unitized leases that share in production from wells drilled on ***other*** leases in the same unit. *Id.* As detailed *infra*, Exxon takes the position that both the unit agreements and lease language that contemplates unitization authorize allocation of expenses in proportion to production shares. The State disagrees.

The second issue concerned the scope of recoverable expenses for "actually drilling" wells "until ready to be put into production." PX182 at 0045773-74. As discussed *infra*, cases have construed such language to encompass not only drilling rigs and well templates, but also downstream production facilities, gathering systems, and treating facilities. Because the 1984 leases expressly excluded pipelines and treating facilities (*see* full ¶ 29(1), quoted above), Exxon did not include costs of the gathering system or the OTF in its payout computations. Exxon also did not include costs of dry holes, which do not lead to wells being "put into production." But Exxon did include costs of full wellstream flowlines and production platforms, which obviously ***were*** required to put the wells into production. DX1191A. Again, the State takes exception.

Exxon of course expected that the State would disagree with some of these interpretations. R1170:1-3 (Condray). It knew that if any of its interpretations were not upheld, it would have to repay the royalties with 12% penalty interest, double the normal prejudgment rate and more than double Exxon's cost of borrowing. PX182 at 0045770; HDX341 at 50000004-14. Exxon fully anticipated, however, that the issues would quickly be joined, and potentially resolved, in the normal audit process. PX182 at 0045770 ("State expected to audit within one-year of first production"); R1049:22-1050:3, 1146:14-1148:5 (Condray).

Exxon did not anticipate, however, what happened next. Exxon did not expect that the State, after completing its audit, would contest ***every*** position Exxon had taken and then counter with an indefensible "best price realizable" claim that more than tripled the State's audit demands. And Exxon had no notice that when efforts to resolve those demands reached an impasse - largely because of the enormous best price claim that every State witness has since repudiated - the State would turn around and hire contingency lawyers to sue Exxon and every other Mobile Bay producer for billions of dollars in punitive damages for

disagreeing with the State's lease interpretation. Unfortunately, that is the story of this case.

IV. EXXON'S REPORTING

Exxon's dealings with State regulators confirm that Exxon had nothing to hide and hid nothing. Before production began in 1993, Exxon applied to the Alabama Oil and Gas Board ("AOGB") for an order approving metering, allocation, and reporting procedures for its Mobile Bay project. DX1096; R2708:16-2709:2 (Bolin). The public file of that proceeding disclosed precisely how Exxon measures, allocates, and reports production of hydrocarbons in Mobile Bay, and provides a roadmap for tracing the disposition of every cubic foot of gas that Exxon produces. DX1096. Notably, AOGB invited DCNR to comment on the proposed procedures.[11] R2712:6-20 (Bolin). DCNR State Lands

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[11] AOGB and DCNR are sister agencies jointly responsible for the development of the State's mineral resources. Recognizing their overlapping responsibilities, the Legislature in 1973 established the Mineral Resources Management Committee, composed of the Secretary of AOGB, the Commissioner of DCNR, and the State Finance Director. *Ala. Code* § 9-5-1 *et seq.* Section 9-5-3 provides:

> The major function of the minerals resource management committee is to maximize the income realized by the state from oil, gas and other mineral resources owned by the state. In order to fulfill this function, the minerals resource

Director James Griggs confirmed to AOGB that they were acceptable to DCNR:

> ***The exhibits [setting forth the proposed metering, allocation, and reporting procedures] were reviewed by our in-house petroleum engineer and our auditor*** with regard to only those matters which bear on royalty revenues to the state....
>
> With regard to the overall metering and allocation process for produced gas and liquids our staff finds no objection. It appears that ***the Exxon configuration and the incorporated Oil and Gas Board staff suggestions adequately protect the state's ability to assure that it is accurately paid the revenues to which it is entitled.***

DX1096A; *see* R2712:21-2713:9 (Bolin).

Consistent with the procedures approved by AOGB and DCNR, Exxon has each month filed sworn production reports with AOGB disclosing, for each offshore well in Mobile Bay, (1) the dry wellstream volume of sour gas; (2) the shrinkage from removal of H_2S; (3) the disposition, by volume, of the resulting sweet gas — whether sold, flared, or used as platform fuel, OTF fuel, or co-gen fuel; and (4)

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management committee is hereby empowered and authorized to conduct the activities of all state departments and agencies, but particularly the department of conservation and natural resources and the state oil and gas board relating to the development of the mineral resources owned by the state.

the volume and disposition of produced condensate.[12] R2721:12-2722:12, 2723:19-2724:12 (Bolin). Exxon also filed sworn monthly reports showing similar information for the OTF on a plant-wide basis, together with monthly sulfur production and disposition. R2726:17-2729:6 (Bolin). As DCNR's auditor agreed, Exxon's reports to AOGB "sho[w] for every lease and every well, everything that comes up out of the ground in Mobile Bay." R2152:9-12 (Snyder).

These reports are public records. R2155:4-13 (Snyder); R2731:4-6 (Bolin). In recent years, AOGB has posted Exxon production information on the Internet. R2731:7-21 (Bolin). As required by statute, AOGB monitors the accuracy of Exxon's metering and the resulting reports on a continuous basis. R2730:1-21 (Bolin). No one contends that these reports were false or misleading (R2730:22-2731:3 (Bolin)). Indeed, the State's auditors used them to check Exxon's production. R2151:10-17 (Snyder); PX254, 258, 261, 256 (audit workpapers including AOGB reports).

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[12] Exxon advised the State that production of condensate (*i.e.*, recovered diesel volume attributable to diamondoids) would be reported only when the revenues began to exceed the costs of fresh diesel injected into the wells. PX253 at *120-*121 (STE0001500-1501). That first occurred in January 1996, and Exxon has duly reported all production and disposition of "condensate" ever since. *Id.*

Paragraph 6 of the 1981 lease form required Exxon also to file sworn monthly reports of hydrocarbon disposition and proceeds, by lease, with DCNR. Unlike AOGB, however, DCNR had no required reporting form. R2276:17-23 (Cone). For the first 11 months of production, Exxon duly paid royalties, but mistakenly did not file these additional reports with DCNR. R1052:24-1053:16 (Condray). Exxon reporting personnel believed the monthly reports to AOGB, which they also sent to DCNR, were sufficient. DX391; R2289:10-22 (Cone); DX1203 (OGB-15 report faxed to State Lands Director Griggs on 9/8/94).

DCNR did not have a revenue analyst in place to review incoming royalty reports during this time and did not call the reporting deficiency to Exxon's attention. DX546 (3/14/94 memorandum from Lands Director Griggs to DCNR Commissioner Grimsley requesting approval for "Revenue Manager type position" to monitor increasing revenues from offshore leases going into production). DCNR first hired such an analyst, Nancy Cone, in October 1994. R2239:6-8 (Cone). No evidence indicates that anyone at DCNR looked for Exxon's reports before Cone arrived.

When Cone attempted to allocate Exxon's monthly wire transfers to individual leases, she noted the absence of royalty reports and called Exxon to request that it provide more information about its payments. R2281:8-18 (Cone). Exxon promptly began doing so, faxing initial reports on December 22, 1994 for the September and October 1994 production months. PX77; PX255 at *178(STE0001431). Exxon then followed with timely reports in January and February 1995 for the November and December 1994 production months. PX255 at *181(STE0001426), *184(STE0001422).[13]

As Cone's notes and memoranda reflect, Exxon worked with Cone throughout this time to develop a reporting format acceptable to DCNR. PX66-67; DX390-392. The initial reports showed "Netted Gross" values (and beginning with the report for December 1994, volumes) for each of the four categories of gas on which Exxon paid royalties - OTF flare gas, platform flare gas, co-gen fuel gas, and residue gas. By late February 1995, after further discussions and a meeting at Cone's office, Exxon and DCNR settled on a report format that disclosed, for each of the four

[13] Under lease ¶6, payments and reports are due on the 15th day of the second month after the production month.

categories (1) the gross value at the tailgate; (2) the "netted gross" value (gross value less the cost netting deductions claimed by Exxon); and (3) the volumes on which the gross and net values were computed. PX242 (report prepared March 2, 1995 for January 1995 production month). In addition, Exxon began filing a separate monthly report of gross and net sulfur values. PX256 at *258.[14]

Exxon reported this information to DCNR every month from 1995 through early 2001, and DCNR accepted Exxon's reports without complaint. R2303:7-18 (Cone). In early 2001, after the first trial in this case, DCNR for the first time issued its own required reporting form. R2153:11-14 (Snyder). Exxon has since reported royalties on DCNR's form, and DCNR has again accepted the reports without any complaint.

From the beginning, Exxon's reports showed on their face that Exxon was cost-netting. As PX242 illustrates, they reported the gross values received by Exxon, and they

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[14] Cone and Exxon agreed that Exxon did not need to reconstruct detailed monthly royalty reports for the 11 months of production before September 1994. DX391. Instead, the State would record this information "when DCNR audits Exxon's operations as a part of the routine audit program." PX67; *see also* DX377 (confirming that Exxon had provided DCNR's auditors with the pertinent records).

reported the "netted gross" values on which royalty was paid. The net and the gross were the same for untreated gas (OTF and platform flare) but different for treated gas ("co-gen" and residue). Anyone reading the reports could see that Exxon was deducting treating costs (and indeed, could calculate the dollar impact of this cost netting on royalties). Similarly for sulfur: the reports showed gross and netted values. They make plain that gross and "netted gross" are not the same, and that royalties were being paid only on the "netted gross." No claim is possible that DCNR was deceived on any of these points.

In fact, DCNR unquestionably knew ***all*** the relevant facts. In its discussions with Cone in early 1995, Exxon candidly disclosed to DCNR its position on the disputed lease interpretation issues. PX67; DX390-392. In March 1995, Cone wrote a memorandum to State Lands Director Griggs and DCNR Assistant Commissioner Macrory reporting on those discussions.[15] She advised them that Exxon was (1)

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[15] The memorandum appears to have been prompted by a note from Macrory, the author of the lease form, who had just returned to DCNR after an eight-year absence from State government. DX170; R1808:10-23 (Macrory). He had heard about Cone's February meeting with Exxon and asked for a report. R1957:21-1958:13 (Macrory); R2299:19-22 (Cone).