In the United States Court of Federal Claims

05-249C
(Filed: July 31, 2012)
(Reissued August 23, 2012)[1]

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NYCAL OFFSHORE
DEVELOPMENT CORP.,

Plaintiff,

v.

THE UNITED STATES,

Defendant.

* *

Breach of contract; Oil and gas leases; Lost profits; Intervening cause

Jeffrey E. Glen and *Philip Raible*, New York, NY, for plaintiff.

Gregg M. Schwind, *Allison Kidd-Miller*, and *Kimberly I. Kennedy* United States Department of Justice, Civil Division, Commercial Litigation Branch, Washington, DC, with whom were *Tony West*, Assistant Attorney General, *Jeanne E. Davidson*, Director, and *Patricia M. McCarthy*, Assistant Director, for defendant.

OPINION

BRUGGINK, Judge.

Plaintiff, Nycal Offshore Development Corporation ("Nycal"), is a partial interest holder in two oil and gas leases, the terms of which we held earlier were breached when the United States materially changed the statutory and regulatory scheme under which development of the leases was to take place. Breach having been established, plaintiff proceeded to trial, seeking to recover the profits it believes it would have recouped absent the breach. Trial was held November 30 through December 10, 2011, in Santa Barbara,

[1] This opinion was originally issued under seal to allow the parties an opportunity to offer redactions. Both parties agree that no redactions are necessary.

California and December 15 and 16, 2011, in Washington, DC. For the reasons set forth below, plaintiff has not proven its entitlement to expectancy damages.

PROCEDURAL BACKGROUND

Plaintiff was originally a consolidated party in *Amber Resources v. United States*, No. 02-30, in which we established defendant's breach of the lease agreements. 68 Fed. Cl. 535 (2005). All other plaintiffs in *Amber Resources* elected to receive the return of the lease payments in restitution.

In 1990 and 1991, Nycal's predecessor in interest acquired a 4.25 percent interest in two of the leases: OCS-P 0460 and 0464. Subsequent legislation delayed and eventually severely limited commercial exploration and extraction, essentially rendering these leases worthless. Consequently, many of the lessees sued here in 2002. We agreed with plaintiffs that the government's actions amounted to a total breach, entitling the plaintiffs to recover. *Id.* at 548-49. All plaintiffs other than Nycal elected to receive restitution, i.e., the return of their lease payments. Nycal declined to make an election at that time and its case was stayed. After further litigation and entry of partial final judgment in favor of the other plaintiffs, we reactivated Nycal's case and deconsolidated it. Nycal elected to seek expectation damages for the profits, if any, it would have reaped but for the government's breach.

Prior to trial, defendant moved to limit plaintiff to restitution or force it to an election prior to trial. It argued that our award of restitution to the other interest holders in the leases at issues made an award of lost profits regarding the same indivisible contract untenable. We disagreed, holding that, in circumstances such as this, with fungible interests in a lease, the co-lessees neither received nor gave up anything "representative of Nycal's interest." *Nycal Offshore Dev. Corp. v. United States*, 92 Fed. Cl. 209, 213 (2010). During oral argument on defendant's motion, plaintiff foreswore its entitlement to restitution as a remedy. *See id.* at 211 n.2.

FACTUAL BACKGROUND

Lease 460 was first issued in 1968 as Lease OCS-P 0186 to Humble Oil Company, which shortly thereafter became Exxon through a merger. Humble paid $36,000,000 for the lease. Exxon drilled three test wells on lease 186, none of which produced oil that flowed to the surface. Exxon tendered the lease back to Minerals Management Service ("MMS")[2] at the expiration of its five-year term. The lease was later renumbered as lease 460. Leases 460 and 464 were issued by MMS, along with a number of other leases sold to other companies, in 1982 to Atlantic Richfield Company ("ARCO") for the sums of $10,967,500 and $9,737,500.

ARCO proposed drilling four exploratory wells on lease 460 in its 1984 Exploration Plan ("EP"). *See* DX 27.[3] Both California and MMS approved the plan. ARCO then drilled one well on lease 460, enumerated 460-1. It produced oil to the surface at a rate of 250 barrels of oil per day ("BOPD"), which qualified as a "discovery" under MMS regulations.[4] ARCO pursued no further exploration of either lease. It concluded that there were insufficient reserves to justify further expenditure. *See* DX 122 at 2.

In 1987, shortly before lease expiration, ARCO sold the leases to Samedan Oil Corporation ("Samedan")[5] and several partners for $500,000. Samedan then requested that MMS add leases 460, 462, and 464 to the Gato Canyon Unit ("GCU") and that it be designated to serve as operator of the unit.[6] DX 27 at 23. That request was approved along with a five-year suspension of the lease expiration to allow for further exploration.

Samedan drilled the 460-2 well, the final well drilled on lease 460. It flowed just over 5000 BOPD. The oil was, however, viscous and tar-like with

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[2] MMS was subsequently renamed the Bureau of Ocean Energy Management, Regulation and Enforcement. We refer to it as it was named at the time the events at issue to place, MMS.

[3] We refer to the parties' exhibits as "DX" for defendant's exhibit and "PX" for plaintiff's exhibit. Joint exhibits are referred to as "JX."

[4] Harold Syms from MMS testified that a "discovery" is a well that flows oil at a rate sufficient to pay for the cost of drilling the well. After an operator has made a discovery on a lease, further exploratory wells are called "delineation" wells.

[5] Samedan was a subsidiary of Noble Energy, Inc., also known as Noble Affiliates Inc. Witnesses used the names interchangeably. We refer to them simply as "Samedan" because it was the named operator of the GCU.

[6] Lease 462 is not at issue in this lawsuit.

an oil gravity of 10-11 degrees API.[7] The GCU unit owners planned to drill one or two more delineation wells before making a decision on whether and where to place a platform to develop the unit.

In 1989, MMS granted a further two-year suspension in order that Samedan might perform a new interpretation of the previous seismic information and drill the next well. In 1992, The unit owners agreed to participate in a project known as the California Offshore Oil and Gas Resources ("COOGER") study. MMS directed a suspension for the duration of the study. Drilling was suspended on the leases pending completion of the study.

In 1997, anticipating completion of the study, MMS requested revised suspension requests for the leases. Samedan asked for an additional 41 months, which would have effectively extended the lease term through 2002. MMS granted the request and listed a number of milestones that it expected Samedan to achieve by certain dates. The final milestone was the start of drilling of the next delineation well on May 1, 2003. *See* DX 52 at 8.

In February 2000, Samedan submitted a Project Description, which it later revised in September 2000. It described the project as "preliminary and subject to change" and stated that the plan might be modified when resubmitted in a Unit Exploration Plan. *Id.* The Project Description contained a description of the type and sequence of exploration activities, description of the process and projected location for the drilling of the next delineation well, information regarding subsurface geology and environmental impact, proposed development activities, and a time line of events leading to production. Included in that production time line were certain major events: (1) submission of a revised Unit Exploration Plan; (2) procurement and mobilization of a mobile drilling rig; (3) drilling of well 460-3; (4) submission of a Development and Production Plan ("DPP"); and (5) installation of a permanent oil platform.

Samedan explained that the 460-3 well would be drilled in the eastern

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[7] Oil gravity is a measurement of how heavy oil is compared to water. The higher the number of degrees, the lighter the oil is compared to the weight of water. The lighter the oil, the easier it is to produce to the surface. This is partially due to the relationship between weight and viscosity. *See* Tr. 2356 (Ershaghi).

half of the reservoir because previous wells had all been placed on the western half. The delineation well would "verify the anticipated reserve volume and gather additional information critical to the development phase . . . ." *Id.* at 20. The owners intended to contract for the services of a mobile drilling rig, known as a "MODU." In conjunction with owners of other undeveloped offshore leases in other units they formed an Offshore Rig Activation Group ("ORA") to further that end.

Pursuant to the National Environmental Policy Act ("NEPA"), MMS published a draft Environmental Impact Statement ("EIS") in June 2001, DX 257, for the delineation drilling proposed for the GCU and other units. The final EIS was never issued, however, due to intervening events precipitated by the state of California's challenge to MMS's 1999 grant of lease suspensions.

On June 20, 2001, the United States District Court for the Northern District of California ruled that MMS had violated the Coastal Zone Management Act ("CZMA"), as amended in 1990, by not certifying that the granted lease suspensions were consistent with California's Coastal Management Program. *California v. Norton*, 150 F. Supp. 2d 1046, 1053-54 (N.D. Cal. 2001). It further held that MMS ran afoul of NEPA by granting a categorical exclusion for lease suspensions from the requirement to prepare an Environmental Assessment ("EA") and/ or EIS. *Id.* at 1057. The district court ordered MMS to "set aside its approval of the requested suspensions" and to "direct suspensions of the thirty-six leases, including all milestone activities, for a time sufficient to provide [California] with a consistency determination in compliance with CZMA" and for MMS to "provide a reasoned explanation for its reliance on the categorical exclusion" of lease suspensions from NEPA-required environmental analysis. *Id.* at 1057-58. The Ninth Circuit Court of Appeals affirmed in December 2002. 311 F.3d 1162 (9th Cir. 2002).

Samedan and several other companies filed a claim in this court in January 2002. A number of companies followed suit in 2004, and Nycal commenced its action in 2005.

DISCUSSION

Liability having been established prior to trial, we must decide whether plaintiff is entitled to expectancy damages and, if so, how much. Plaintiff seeks expectancy damages equal to the profits plaintiff would have earned absent the breach. Plaintiff is entitled to only those damages that it can prove

(1) were foreseeable at the time of contract formation, (2) were actually caused by the breach, and (3) are reasonably certain. *See Cal. Fed. Bank v. United States*, 395 F.3d 1263, 1267 (Fed. Cir. 2005).

The question of foreseeability asks whether the damages sought by plaintiff were reasonably foreseeable or actually foreseen by the breaching party at the time of contract. *Landmark Land Co. v. United States*, 256 F.3d 1365, 1378 (Fed. Cir. 2001); Restatement (Second) of Contracts § 351(1) (1982). "Loss may be foreseeable as a probable result of a breach because it follows from the breach (a) in the ordinary course of events, or (b) as a result of special circumstances . . . that the party in breach had reason to know." *Id.* § 351(2).

Defendant's breach also must be the "proximate cause" of plaintiff's damages. *Old Stone Corp. v. United States*, 450 F.3d 1360, 1375 (Fed. Cir. 2006). The Federal Circuit has accepted two different standards in deciding the issue of causation. The seemingly "lighter" of the two standards requires that plaintiff show that the breach was "a substantial factor in the damages." *Ind. Mich. Power Co. v. United States*, 422 F.3d 1369, 1373 (Fed. Cir. 2005). The other approach asks whether, "but for the breach," plaintiff would have suffered damages. *See Cal. Fed. Bank*, 395 F.3d at 1268. Under neither test does the breach have to be the "sole factor or sole cause in the loss of profits." *Id.* It is within the trial court's discretion which formulation to follow. *Citizens Fed. Bank v. United States*, 474 F.3d 1314, 1318 (Fed. Cir. 2007).

The third element of plaintiff's burden of proof, reasonably certainty, calls on Nycal to establish that there would have been profits absent the breach and that "a sufficient basis exists for estimating the amount of lost profits with reasonable certainty." *Energy Capital Corp v. United States*, 302 F.3ed 1314, 1325 (Fed. Cir. 2002). This can often prove to be a difficult and sometimes insurmountable obstacle in expectancy damages cases. *See Glendale Fed. Bank, FSB v. United States*, 378 F.3d 1308, 1313 (Fed. Cir. 2004). That is not to say, however, that lost profits are categorically excluded. The Federal Circuit has noted that "uncertainty as to the amount [of damages] will not preclude recovery;" the court must be able to "make a fair and reasonable approximation of damages." *Bluebonnet Sav. Bank, FSB v. United States*, 266 F.3d 1348, 1356-57 (Fed. Cir. 2001); *Glendale*, 378 F.3d at 1313 (quoting *Bluebonnet*, 266 F.3d at 1356-57).

Defendant challenges plaintiff's proof as to all three elements. It argues that no profits were foreseeable at the time the lease was issued in 1982, in large measure because MMS was skeptical about the amount of reserves. Even if it could have been foreseen that terminating the lease might interfere with profitable development, it contends that the breach did not cause any loss for at least two reasons: plaintiff has not established that the owners were motivated to proceeded to development and, second, the owners could not have obtained the necessary environmental permits needed for further exploration and production of the leases. Defendant also argues that there is an insuperable level of uncertainty in plaintiff's claim for three reasons: first, because of the inherent uncertainty of the volume of reserves, making development of the unit a new and untested venture; second, because plaintiff would not have been able to finance its own involvement in further exploration and development of the lease; and third, defendant argues that the GCU would not have made any money due to the high costs involved in bringing the unit to production. We turn now the particulars of this case.

I. Foreseeabilty

Defendant argues that plaintiff has not shown that either the type or the amount of damages were foreseeable when MMS issued the leases in 1982 because the agency did not actually foresee, nor should it have foreseen, that the leases would have produced the approximately \$5.2 billion of oil and gas contemplated in plaintiff's claim.[8] Defendant cites *Anchor Savings Bank, FSB v. United States*, 597 F.3d 1356 (Fed. Cir. 2010), for the proposition that "the relevant foreseeability inquiry is not whether the leases were issued for the purpose of producing oil and gas, but whether lost profits, and lost profits on the order of \$5.2 billion, were reasonably foreseeable or actually foreseen by the breaching party at the time of contracting." Def.'s Post Trial Br. 44 (citing *Anchor Sav.*, 597 F.3d at 1361). Defendant points to two particular pieces of evidence – the industry's bids on the leases and MMS's internal estimates of the value of the leases.

ARCO, Samedan (for a consortium of companies), and Exxon bid on leases 460 and 464 at the 1982 lease auction. Defendant produced the following summary of the sale:

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[8] Plaintiff's best case scenario is that the leases would have produced \$5.2 billion worth of oil and gas, which represents an undiscounted net income for the 100 percent interest of the leases. Nycal's share would be its 4.25 percent interest after it was properly discounted to account for the time value of money, net of lease royalties.

Lease	Bids	MMS Estimates	MMS Value
460	$10, 967, 500 (ARCO) $4,636,500 (Samedan et al) $3,225,000 (Exxon)	21.4 MMBO (Oil) 55.7 BCF (Gas)	– $12,712,929
464	$9,737,500 (ARCO) $201,000 (Samedan et al) $103,500 (Exxon)	1.7 MMBO (Oil) 5.2 BCF (Gas)	– $670,310

See DX 685 at 18-20 (bid summaries); DX 743 (MMS's evaluation data sheet); DX 1004 (MMS 1982 lease sale summary chart). As the chart shows, MMS estimated that the leases would ultimately lose money if developed. Harold Syms, MMS senior geologist and eventual Chief of Resource Evaluation, testified that MMS would have accepted a minimum bid of just over $84,000 for lease 460 and just over $24,000 for lease 464, which translates to $25 per acre. Tr. 3663, 3667-69; *see also* DX 1004. He explained that $25 per acre is MMS's minimum accepted bid even when it values the leases as unprofitable. Although MMS internal estimates are not released prior to sale, it is known that $25 per acre is the minimum bid even when the agency places a negative value on prospects. *See* Tr. 3667. When asked why MMS offered these leases for sale even if its internal value estimates were negative, he explained that certain oil companies had requested that the lands be released for sale. Tr. 3668.

The result of this evidence, in defendant's view, is that MMS did not foresee, nor should it have foreseen, that the leases would ever be profitable. Therefore, plaintiff's damages, even if proven, were not foreseeable and cannot be recovered.

Plaintiff spent little time dealing with the issue of foreseeability, and we are inclined to see why. There can be no doubt that the leases were issued so that private oil companies could explore for oil and gas and, if oil and gas was located in producing quantities, go into production. We can safely assume that MMS officials understood that possibility even if preliminary data suggested to MMS that the prospects were not good. ARCO paid almost $21 million for the leases, by far the largest bid per acre for any of the leases offered at the 1982 sale. MMS was certainly on notice of ARCO's intent to exploit the leases to the maximum extent possible. Both parties understood that, if there were economically viable reserves on the leases, then the oil companies had earned the right to produce them. Although MMS made no guarantees as to quantity, at a minimum it was warranting that the government would stand by the raffle ticket it was selling, no matter how profitable it turned out to be. The oil companies assumed the risk that the oil and gas were not there. The government assumed the risk that, if it interfered with that option to explore, it was on the hook for whatever profits could be established with meaningful certainty. We presume the government would not have declined to accept its 16 percent royalty payments on the ground that it was an undeserved lagniappe. In the context of a government oil and gas lease, we believe it is sufficient to establish foreseeability that there was a reasonable probability of recoverable reserves. *See First Fed. S&L Ass'n of Rochester v. United States*, 290 F. App'x. 349, 357 (Fed. Cir. 2008).

The central question in a foreseeability analysis is whether the breaching party had reason to anticipate that its breach would cause the type of loss that plaintiff incurred. *Anchor Sav. Bank*, 597 F.3d at 1364.[9] The fact that the breaching party does not anticipate the amount of the loss is not dispositive. *Id.* (citing the Restament (Second) of Contracts § 351 cmt. a (1981)). "The party in breach need not have made a 'tacit agreement' to be liable for the loss. Nor must he have had the loss in mind when making the contract, for the test is an objective one based on what he had reason to foresee." Restatement (Second) of Contracts § 351 cmt. a. The lessor's repudiation of an oil and gas lease clearly would cause plaintiff to lose precisely the benefit it bargained for, namely, profits it might have earned had the lease been developed. Plaintiff bears the burden of proving that the lease would been developed and would have ultimately been profitable, but those are issues of causation and quantum of damages, not foreseeability.

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[9] The court in *Anchor Savings* quoted the following passage from *Farnsworth on Contracts* as support for its holding that damages were foreseeable in that case: "[t]he magnitude of the loss need not have been foreseeable, and a party is not disadvantaged by its failure to disclose the profits that it expected to make from the contract. However, the mere circumstance that some loss was foreseeable may not suffice to impose liability for a particular type of loss that was so unusual as not to be foreseeable." 597 F.3d at 1364 (quoting E. Allan Farnsworth, *Farnsworth on Contracts* § 12.14 (3d ed. 2004)).

II. Causation

It is so costly to explore for and produce offshore oil and gas that, without a significant quantity of recoverable oil and gas, plaintiff cannot prove that breach caused it any damage. Consequently, much of the trial focused on the parties' competing views of how much oil (primarily) and gas could have been recovered in the GCU. Defendant's experts were of the view that the volume was not sufficient to make production anything other than marginally profitable. Plaintiff's experts took a contrary view, ultimately asserting damages in the range of $72,000,000. In addition, however, defendant contends that, even if there were enough oil and gas in the reservoir that it could have been sold for more than the cost of production, there are two independent reasons why plaintiff cannot establish causation: first, that it has not proved that the owners would have gone forward with production, and second, that further exploration and development would have been blocked by environmental permitting difficulties unrelated to the breach.[10] Although we ultimately find that environmental permitting impediments would have prevented development, we will proceed to resolve the principal factual dispute dividing the parties: the question of how much oil and gas could have been recovered.

The GCU is located between two producing oil and gas fields off the coast of southern California. The Hondo Field is located in federal waters to the west of Gato Canyon and is part of the Santa Ynez Unit. The South Ellwood Field lies in state waters to the east of the GCU.[11] One particular strata below the surface is the source of the bulk of the recoverable oil in this area. It is known as the Monterey Formation, which underlies both the land and sea surface in Southern California. The offshore fields are often described in the industry as the "Offshore Monterey." The offshore Monterey formation brings with it a host of challenges in estimating reserves, particularly in a field which has never produced.

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[10] Defendant also offers a third independent obstacle to causation–namely, that plaintiff could not have obtained the financing to participate in development. While defendant raised serious concerns in that regard, because of our independent finding that environmental problems would have prevented development, we need not resolve the issue.

[11] Adjacent to the South Ellwood field is the Ellwood field. Both are partially producing fields and are both located entirely in state waters.

The various estimates were generated using two different methodologies. The one used by plaintiff's experts and in most of the pre-litigation reports is a gross rock volume method. In this methodology, the oil reserves are estimated by calculating the gross volume of oil-bearing rock and then multiplying it by a recovery factor. The rock volume is calculated by setting the areal bounds of the reservoir and multiplying that by the distance from the top to the bottom of the productive rock. Both of those inputs are derived primarily from seismic and well data. The bottom of the reservoir is normally determined by well tests, from which the depth at which water is produced in the well bore can be identified. This is known as the oil water contact ("OWC") and it represents the bottom of the productive rock. Below the OWC it is not practicable to recover oil. The recovery factor is generally selected by reference to one or more analogous fields that are in production, from which a barrels per acre foot ("BPAF") factor can be determined.[12] Plaintiff went a step further by then using these inputs to conduct a statistical analysis known as a Monte Carlo simulation to produce what it believes to be the most likely scenario.

Defendant's expert, Dr. Iraj Ershaghi, took a different approach because he was not comfortable using the gross rock volume method. We will examine his reasons below. Dr. Ershagi instead selected what he believed to be the most analogous field, South Ellwood, and multiplied the median well performance by plaintiff's number of proposed wells (18). He increased the production numbers for the South Ellwood median to account for the fact that the wells there are still producing oil and because the Gato Canyon has certain geological factors that are more favorable for production compared to South Ellwood.

A. Pre-Litigation Estimates

When MMS initially issued the leases in 1982, it estimated that approximately 23 million barrels of oil ("MMbbl") along with 60.2 billion cubic feet ("BCF") of natural gas, underlay the leases. *See* DX 1004. The natural gas is of considerably less importance than the oil. The same document showed that MMS estimated an ultimate loss of over $13 million for the two leases, assuming they went into production. This was based primarily on the

[12] The recovery factor from a producing field is calculated by using a decline curve to estimate the ultimate recovery and dividing that into the volume of the reservoir.

earlier exploratory work done by Exxon in the 1960s on lease 460.

In May of 1989, a report issued by Norcen, then the largest interest holder in the GCU, laid out three scenarios for the ultimate recovery at the GCU. At the bottom of the range, it estimated 65.2 MMbbl, at the top of the range 81.4 MMbbl, and a "most likely" scenario of 73.3 MMbbl. DX 141 at 15. The three scenarios were based on a recovery factor of 68 BPAF, which the report states was selected based on the work of Dr. Mannon. *Id.* at 4.

In a 1995 MMS document, "The Gato Canyon Field Extension Study: A Project Summary Report," author Dennis Tayman outlined a strata by strata analysis of the top four most productive intervals and concluded that Gato Canyon field contained 47 MMbbl in recoverable oil. *See* DX 752 at 2-6. The report also notes that the 47 MMbbl figure appeared in MMS documents as early as December 1993. *Id.* at 5. The 47 MMbbl figure reappears in the Minerals Management Service Pacific OCS Region Field & Reservoir Reserve Estimates As of December 2008, dated August 26, 2009. DX 745 at 4. This estimate was the product of the gross rock volume method.

Dr. Mannon produced several estimates prior to his engagement by plaintiff in this litigation. He and his firm, Mannon & Associates, produced reports for the lease owners in 1992, 1995, and 1996. In 1992, Dr. Mannon's firm produced an economic feasibility study of the GCU, which at that time included lease 187. Using a recovery factor of 53 BPAF for the segment below 5800 fee subsea and a factor of 75 above 5800 feet below sea level, Dr. Mannon calculated a reserve number of 80.7 MMbbl for lease 460 and 1.4 MMbbl for lease 464. DX 70 at 5, 17.

In 1995, Mannon & Associates issued a valuation of the offshore California federal units. In that report, it estimated oil production for the GCU at 72.59 MMbbl with 102.65 BCF of gas. DX 812 at 2. The reserves were classified as "proved undeveloped reserves."[13] *Id.* at 1. The 1995 report also contained an economic analysis suggesting that development would be profitable for the GCU owners.

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[13] Proved undeveloped reserves are defined by the Securities and Exchange Commission as "reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for completion." DX 812 at 5 .

In 1996, Mannon & Associates produced a valuation of Nycal's interest in the GCU as of July 1, 1996. Dr. Mannon calculated the gross rock volume of the GCU and applied a 62 BPAF recovery factor for lease 460 and a factor of 40 for lease 464. Dr. Mannon testified that the lower recovery factor for lease 464 was due to his lack of well data to act as a control on the seismic data. Tr. 1518. He explained that the 62 BPAF recovery factor was derived by looking at the recoveries at three producing neighboring units, Point Pedernales, Hondo, and Arguello. *Id.* at 1518. Of the three, "[i]t was mainly based on Point Pedernales, because even at that point, we saw that there was a very distinct similarity in the two reservoirs, which would be very appropriate to use this as an analogous reservoir." *Id.* Dr. Mannon arrived at a estimated ultimate recovery ("EUR") of 80.6 MMbbl for lease 460 and 8.857 MMbl for lease 464. PX 18 at 3. These reserves, like those in his 1995 report, were classified as "proved undeveloped." *Id.* at 11. Using the inputs described above and "oil and gas prices of $11.05/B and $1.68/MCF," Dr. Mannon estimated the net income for Nycal's share, discounted to present value at 8 percent, to be $6.37 million paid out over 9.03 years. *Id.* at 4. Discounted to present value at 10 precent, Nycal's net income would drop to $4.64 million. At a discount rate of 20 percent, Nycal would net only $400,000. *Id.*

In 2001, MMS issued a draft EIS regarding delineation drilling in the offshore Santa Barbara area, which listed the GCU as holding 77 MMbbl of oil reserves with an additional 46 BCF of gas. DX 257 at 87. There was much debate at trial and in the post-trial briefing regarding the source and import of that figure. Defendant called MMS employee Harold Syms who worked as a geologist, well log analyist, and eventual supervisor/senior geologist for the "valuation of undiscovered resources nationwide." Tr. 3650. He testified on direct examination that the 77 MMbbl figure was provided to MMS by the GCU operator, Samedan. He was asked if it was "a new MMS estimate." Tr. 3730. He answered that "[i]t was not. This is based on information supplied by the operator." *Id.* On cross-examination, Mr. Syms clarified that the 77 MMbbl figure was devloped by an MMS engineer "based on the number of wells that the operator submitted," a "production profile for each well," and the "timeframe of the project." Tr. 3799. The operator supplied a number "in the 80s" and MMS then refined it based on the inputs described above, which resulted in a 77 MMbbl figure. *Id.* Mr. Syms was unequivocal in stating, however, that this was not an MMS reserve estimate but rather represented a "worse case scenario," determined for purposes of an environmental impact statement. Tr. 3802 ("Q: Sort of a worst case? A: Worst or best, depending on how you look at it."). The figure, in short, was not an endorsement of any reserve estimate.[14]

B. Estimates Prepared for Litigation

Both parties retained experts to assist them in estimating the reserves in the GCU. Plaintiff retained the services of Subsurface Consultants and Associates, LLC ("SCA") to perform a series of reserve estimates.

1. SCA Reports

SCA generated three reserve estimates in two separate reports. One, which it characterized as "deterministic," calculated the reserves using static inputs for the gross rock method described previously. The two other estimates were "probabilistic" and were derived by application of a Monte Carlo Simulation, a method of statistical analysis used in calculating probabilities of outcomes.

In order to produce its estimates, SCA first conducted a new interpretation of the 1980s seismic data originally produced by ARCO. This interpretation was conducted by Alan Cherry. Mr. Cherry holds a bachelors of science degree in geology from Fredonia State University in New York, and he completed a three-day course in geophysics in the 1980s. This was his first experience working in offshore Monterey. He was offered and accepted as an expert in seismic interpretation and probabilistic analysis. He testified to being "self taught" in the areas for which he was offered as an expert. Tr. 532.

Although technology and software has come a long way in assisting seismic interpreters, the quality of the data itself and the intense fracturing present in the Monterey formation make it difficult to accurately interpret

[14] Though not a MMS reserve estimate as such, the figure did reappear twice in subsequent MMS documents. In September 2001, in a presentation made at Santa Barbara City College entitled "Significance of the Monterey Formation California OCS," the GCU was listed as a possible new development with 77 MMbbl of potential recovery. DX 753 at 12. In 2005, a Environmental Information Document for Post-Suspension Activities again referred to 77 MMbbl along with 46 BCF of gas for the GCU. DX 258 at 5.2-11. The environmental information document would presumably be subject to the same disclaimer as the 2001 EIS: that it was not a reserve figure but a sort of "worst case" scenario for environmental impact purposes.

precise data points. “One of the main problems encountered in picking the top of the Monterey Formation on seismic data is the presence of numerous faults and distortion of seismic reflectors at the crest of the Gato structure.” PX 42 at 20 (2009 SCA Report). Mr. Cherry testified that the Gato Canyon reservoir was “one of the most complex structures” he had ever seen. Tr. 541. In fact, without well data acting as a control, an interpreter cannot readily determine what particular lithological layer he is viewing in the seismic data. *See* Tr. 560-64 (Cherry). This presented an additional level of difficultly when Mr. Cherry was unable to trace one particular feature in the seismic lines from one well to the next.

Another SCA geologist, Gary Chapman, provided his own interpretations of the well logs from the GCU and wells on adjacent state leases in order to pick the top and bottom of the layers, which Mr. Cherry then incorporated into his mapping. He was chiefly responsible for two very important pieces of SCA’s mapping and resulting reserve estimates: SCA’s top of Monterey and the OWC picks, which basically establish the top and bottom of the reservoir in its estimates. As with Mr. Cherry, Mr. Chapman’s SCA’s litigation reports were his first experiences working in the Monterey.

a. SCA’s First Monte Carlo Simulation

The first of the SCA estimates was the product of five inputs displayed in plaintiff’s May 2009 expert report:

Parameters	**x(min)**	**x(prob)**	**x(max)**
Net pay, feet	600	808	1200
Porosity	0.080	0.17	0.24
Oil saturation	0.55	0.60	0.65
Area, acres	1400	1724	2000
Recovery	0.08	0.10	0.15
Bo	1.20	1.2	1.2

PX 42 at 21. As described in the report, the probabilistic calculation used “software tools to randomly sample the range of variables in the reserves calculation and repeat the calculation thousands of times.” *Id.* The results of the thousands of calculations are described as “pyramid shaped” with the peak being the “most likely output.” *Id.* The results:

Areal extent of reservoir:	1,724	acres (from map)
Gross volume of reservoir	1,581,734	acre feet (back calculated)
Recovery Factor	58	barrels of oil per acre foot
Expected oil recovery	91,740,600	barrels
Gas/Oil ratio	variable	. . .
Expected gas recovery	129,7214,210	thousand cubic feet of gas

Id. at 22.

In the report, SCA makes the claim that this probabilistic approach is superior to conventional deterministic estimate because a deterministic method relies on only one estimate for each variable, which, according to SCA, often biases the result in the direction of the interpreter’s view of the reservoir and thus makes it “inevitably incorrect.” *Id.* at 21. SCA also cites the difficulty of “attempting to segregate the Monterey into zones of variable rock and fluid properties which are difficult to measure and predict in the Monterey.” *Id.*

The ultimate result of this analysis was an estimate of 91.7 Mmbbl. The gross volume of the reservoir was “back calculated” from the results by, in essence, dividing the estimated recovery by the recovery factor. The variables of net pay, porosity, and oil saturation are not, however, used for the traditional gross rock volume method of calculating reserves in the offshore Monterey. Those variables are associated with the “volumetric” approach normally associated with traditional sandstone reservoirs.[15] As a result of that criticism from defendant’s expert Dr. Ershaghi, SCA produced a second report.

[15] Plaintiff’s expert, Dr. Robert Mannon explained that, in a conventional reservoir, one can calculate the “net pay” of oil-bearing rock by identifying and eliminating non-productive intervals or layers. This is not possible in areas such as the offshore Monterey due to intense fracturing, which makes it difficult, if not impossible, to differentiate between productive and non-productive intervals. TR. 1504-1505. Thus reservoirs in the offshore Monterey are not amenable to traditional volumetric calculations.

b. SCA's Second Monte Carlo Simulation

In response to Dr. Ershaghi's criticism of the variables used in the first Monte Carlo Simulation, Mr. Cherry ran a second simulation. This time his inputs were limited to area, height, and recovery factor. He selected minimum, maximum, and probable values for each parameter. Mr. Cherry testified that the probable numbers are the most important for the Monte Carlo simulation because the simulation is weighted towards the probable results.

In order to come up with minimum values for the second Monte Carlo simulation, Mr. Cherry testified that he created a new map using certain minimum known information. Selecting a known data point from an exploratory well, such as the top of the Monterey, he used an algorithm called "creaging." Tr. 1119. "Creaging is the geostatistical calculation [which] looks at the distances between data points and calculates or interpolates values between those points." *Id.* In other words, he input the data for the top and bottom (OWC) of the reservoir and used an algorithm to extrapolate in between those points.

For his maximum values, Mr. Cherry selected top height and bottom depths as well as areal bounds from a map supplied by Dr. Ershaghi. He viewed this as a reasonable set of data points for a maximum value. For the all-important probable values–those values most heavily weighted in the calculation–Mr. Cherry used the seismic map created by SCA for litigation.

For recovery factors, SCA selected a range of factors that it termed a table of "Reported Monterey Recovery Factors." PX 58 at 6. The low in the table was 19-21 from the Jalama Field at the Rocky Point unit. The high was 143 from the "chert zone" at the Hondo field. *Id.* For the simulation, SCA selected 30 for the minimum, 90 for the maximum, and Dr. Mannon's factor of 58 for the probable number. Tr. 1125-26 (Cherry).

The result of all of this was as follows:

Geologic Parameters	Minimum	Probable	Maximum
Area (acres)	1000	1724	2300
Gr. Height	537	800	1343
RF (bbl/AF)	30	58	90

Recoverable Hydrocarbons (Probabilistic)

	P90	P50	P10	Pmean
Million bbls	37	78.4	146.8	92.4

Id. at 7. The P90 number represents a value which at least 90 percent of the simulations achieved, meaning that the program predicts a 90 percent likelihood of achieving at least that result. P50 is effectively the median result. P10 represents the upper level of achievable results, with only a 10 percent likelihood of achieving that number or better. The Pmean is the number that the program predicts as the most likely to occur, which corresponds to a number that the simulations reached or exceeded 35 percent of the time. The Pmean result of 92.4 MMbbl is the average of all of the simulation results. It is higher than the median P50 number because of the "log normal distribution" which was selected for the simulation. Tr. 1132 (Cherry).

Mr. Cherry explained log normal distribution in this way:

> Some wells are good, some wells are poor. What we find is that the average well is greater than the typical well. . . . [I]n general, you'll find that an average well for the Monterey is 3 to 4 million barrels. A typical well, a median well, where it's 50 percent occur less, 50 percent more, it's more like 2.2 million barrels. And that difference between the mean and median is a function of having a log normal distribution where the values that occur out at the high end are very infrequent, but they do occur, and they have an impact on your expected ultimate recovery . . . .

Tr. 1133. That is to say, as Mr. Cherry further explained, there are more poor wells than good wells, but "the good wells produce so well, they pull the average up." Tr. 1135. If those results were plotted on a curve, "the shape of that type of distribution is very similar to the shape of the distribution that you get when you're performing this type of analysis."[16] *Id.*

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[16] Mr. Cherry testified that "the [oil] industry likes the Monte Carlo simulation [] because it generates a log normal distribution. And what they found is the mean result from log normal distribution is usually somewhat significantly higher than something that went straight from the deterministic." Tr. 1100.

c. SCA's Deterministic Estimate

Mr. Cherry and SCA also performed a traditional "deterministic" gross rock volume estimation. SCA selected the "probable" figures from its second Monte Carlo simulation and simply multiplied the gross rock volume by the recovery factor of 58. The result was 80.7 MMbbl. It also ran scenarios, including best and worst, but keeping the recovery factor consistent at 58 throughout:

Case	Ave. Ht. (ft.)	Area (acres)	Volume (acre ft.)	Recovery Factor (bbl/AF)	EUR (million bbls.)
Minimum	537	1,020	547,740	58	31.8
Most likely	807	1,724	1,391,268	58	80.7
High Side	1,546	1,667	2,577,182	58	149.5
Absolute Max.	1,343	2,360	3,169,480	58	183.8

PX 58 at 10.[17] As with the rest of SCA's estimates, the reserves were not assigned a classification on the Petroleum Resources Management System ("PRMS") classification scale.

2. Dr. Ershaghi's Report

Dr. Ershaghi took a different approach in making his reserve estimate. Dr. Ershagi is a petroleum engineering professor and chair of his department at the University of Southern California. He is widely published and well known for his work regarding the Monterey formation in California. We accepted Dr. Ershaghi as an expert in reservoir engineering, characterization, forecasting, and geostatistics.

A number of conclusions lead Dr. Ershaghi to take a different approach

[17] In the original exhibit, the height figures for the "High side" and "Absolute Max" scenarios were reversed. This was a clerical error.

to his reserve estimation. Looking at the data from the exploratory wells, he believed that an OWC could not be established with enough certainty because the seismic data did not allow for an accurate pick of the top of the Monterey formation in the Gato Canyon field. He testified that the unproductive intervals in the Monterey, and especially in Gato Canyon, also made the use of a gross rock volume estimate inappropriate. Tr. 2387-88. In light of those conclusions, Dr. Ershagi bases his estimate on production from neighboring wells.

Dr. Ershagi stated that he looked at all of the producing Monterey fields and their lithologies and selected the South Ellwood field as the "most similar lithological-wise." Tr. 2411. He then looked at the well by well production in that field and selected the median well production as his starting point, which was approximately 1.1 MMbbl. Accounting for oil yet to be produced from the field–an additional 10-20 MMbbl–and giving the field the "benefit of the doubt" because it is located further from shore than the GCU and thus has "better quality rock," he bumped the figure to 2.2 MMbbl for median well production. He stated that this was "very generous in terms of well productivity." Tr. 2412.

Dr. Ershaghi then took SCA's projected number of wells (18) and multiplied this by his per-well number. The result was 39.6 MMbbl.[18] Additionally, he looked at the well spacing at the South Ellwood field and calculated that an operator of the GCU might only place 12 wells on that field, which would bring his estimate down to 26.4 MMbbl.[19] Dr. Ershaghi ultimately concludes that further exploratory drilling would be necessary to substantiate any claim of commercial viability.

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[18] It is unclear how Dr. Ershaghi selected 18 as Dr. Mannon's number of proposed wells. Dr. Mannon's 1996 report lists 16 as the number to be drilled, PX 18 at 17, and his 2001 report includes 22 initial wells and eight re-drills, PX 47 at 8. Using 22 wells, Dr. Ershaghi's approach would yield 48.4 MMbbl.

[19] "And looking . . . at the South Ellwood, roughly about 30 wells with somewhere around 3.9 million acre feet, you see the that the drainage volume per well is around 130,00 acre feet." Tr. 2413 (Ershaghi). The SCA area estimate of "roughly 1.5 million [acres] . . . , gives you about 10 [or]12 wells, not 18 wells." *Id.*

C. Our Finding: The GCU Holds Approximately 60 Million Barrels of Oil

Defendant criticizes plaintiff's estimates for a number reasons. It disagrees with the inputs that SCA and Dr. Mannon used in both the Monte Carlo simulations and deterministic model, i.e., size of reservoir (areal extent and OWC) and recovery factor. Defendant further criticizes the Monte Carlo methodology employed by SCA as subjective in that the results are highly dependent upon the selection of minimum, maximum, and probable values and because defendant views the Pmean value produced to be skewed upward as a result of log normal distribution. Defendant also believes that plaintiff's choice not to classify its reserves according to the PRMS system illustrates the uncertainty in plaintiff's estimates.

Plaintiff responds that SCA's work is buttressed by the variety of pre-litigation estimates produced by Norcen, MMS, and Dr. Mannon. The Monte Carlo simulation is, in plaintiff's view, a well respected method for estimating reserves in oil fields. Plaintiff responds to Dr. Ershaghi by arguing primarily that Dr. Ershaghi's median well approach improperly discounts the effect of the outlier high-producing wells on the ultimate production of fields in the offshore Monterey region. Plaintiff additionally criticizes Dr. Ershaghi's selection of his median well number from the South Ellwood field, arguing that it is not a useful analog primarily due to geological factors.

We find that both parties' approaches provide us at least some clue as to the likely quantity of reserves at the GCU. Neither are without fault, however, and we cannot therefore adopt either method in whole. For the reasons set out below, we find that Gato Canyon reservoir holds approximately 60 MMbbl of oil.

Plaintiff's proffered reserve estimates, though susceptible to criticism, are not wholly unreliable, with one exception.[20] We take them as the upper limit of an optimistic view of the reservoir underlying the GCU. Plaintiff's

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[20] We reject plaintiff's volumetric approach taken in its first Monte Carlo simulation. Mr. Cherry ultimately rejected that methodology himself in favor of his gross rock volume approach taken in the second Monte Carlo simulation. He testified on cross-examination that he recommended that SCA not include the first volumetric calculation in its report. *See* Tr. 1177-78.

deterministic and probabilistic gross rock volume calculations are properly criticized as products of subjective inputs. Plaintiff's experts made seismic interpretations from data that was very difficult to interpret. *See* Tr. 558-559 (Cherry). This made identifying the top of the Monterey formation speculative. Much of the GCU reservoir as mapped by SCA has never been tested by wells. This is not uncommon; oil companies and MMS routinely make reservoir maps based on seismic data alone. Mr. Heck, in fact, wrote in 1999 that,

> detailed mapping of the structure is very difficult due to extensive faulting. Each of the wells that has been drilled has penetrated a series of faults that have crumbled and moved the rock layers into various relationships that can be confusing to the geologists and geophysicists attempting to map the dimensions of the accumulations . . . .

DX 10 at 1 (History of Exploration of the Gato Canyon Structure); *see also* DX 118 at 1, 7; DX 47 at 2; DX 49 at 3; DX 83 at 17. Mr. Heck echoed that sentiment at trial when he testified that faulting in the structure lowered the quality of the seismic data and made it difficult to know when drilling "into the Monterey whether we're in the middle of the section or the top of where we are in the Monterey." Tr. 791-92. Dr. Ershaghi criticized SCA's work in large measure because he viewed the seismic data as unreliable in determining the top of the Monterey and the well data as insufficient to determine the bottom OWC or bottom of the reservoir.

Mr. Cherry ultimately was forced to use his best judgment to fill in the gaps in the data or rely on the judgment of others like Dr. Mannon. Samedan and the other owners, knowing these difficulties, tasked Mr. Heck and Dr. Mannon to do the same things prior to litigation. Relying on an interpreter's experience and judgment does not render an estimate unreliable per se, however. We are able to take into account the various difficulties and challenges in the underlying data as well as the interpreter's experience in assigning weight to SCA's estimates.

Plaintiff adds an additional level of complexity to the task at hand by introducing the probabilistic method. As we explained earlier, the Monte Carlo simulation calculates probable outcomes based on the input of minimum, maximum, and probable values and the selected statistical distribution pattern. Defendant is right to point out that this approach is very susceptible to manipulation by skewing either of these inputs towards the result desired. That is not to say that it is completely unreliable, however.

Mr. Harold Syms, a geologist employed by MMS during the relevant years, testified that MMS used "Monte Carlo sampling for a quite a few of the variables" in its "lease sale model." Tr. 3769. This method was used for the GCU lease sale in 1982, for example. Mr. Syms explained that "Monte Carlo sampling" was used to "estimate the range that exists and where the likely tendency might be." *Id.* The determination of the "likely tendency" is in large part a result of the selection of the distribution pattern: "For instance, when something is the product of a bunch of things multiplied together, generally log normal seems to be a good distribution for that, whereas if you don't know much about something you would use triangular distribution." Tr. 3771. He stated that some variables were "more appropriate for [a] log normal" distribution pattern." *Id.*

Mr. Syms also testified that, on a macro scale, in the Santa Barbara-Ventura Basin-Monterey Fractured Play, MMS expects a "log normal distribution of sizes" of the fields within the region.[21] Tr. 3765. "You'll see a few very large ones and a bunch of smaller ones that will form a log normal distribution." *Id.*; *see also* PX 86 at 12 (MMS 1995 National Assessment of United States Oil and Gas Resources Assessment of the Pacific Outer Continental Shelf Region). We cannot reject SCA's probabilistic estimates based on the fact that they are probabilistic or that they employ a log normal distribution. These methods are used by the government and private industry for the region in which the GCU is located, and we have not heard any principled reason to reject them.[22]

We do, however, view plaintiff's Monte Carlo estimates as skewed, primarily, by the selection of recovery factors. Mr. Cherry used Dr. Mannon's 58 barrels per acre foot as the probable figure, 30 for the low value, and 90 for the high value. The probable figure is the most important in the calculation of

[21] "A play is a group of geologically related cumulations. . . . So they have a similar history, a geologic history of source, of trapping, of creation of the traps, of preservation, of hydrocarbons . . . ." Tr. 3755-56 (Syms).

[22] We also received testimony in the form of a deposition from Cam Countryman, appearing as the Rule 30(b)(6) designee on behalf of Samedan, in which he indicated that Samedan uses a probabilistic methodology when estimating the size of a reservoir. *See* JX 3 at 73-74.

the Pmean, or most likely, result. The 58 figure was the same figure used for the recovery factor in SCA's first Monte Carlo simulation. Mr. Cherry testified that, in response to Dr. Ershaghi's criticism of the first Monte Carlo, SCA performed a "research study trying to compile information from various reports and various studies to compile a range of gross rock volume recovery factors so that we could have a basis for the reasonableness of that 58 barrels per acre foot that we used in the first report." Tr. 1113.

Mr. Hal Miller performed this research and compiled the table of recovery factors used to buttress SCA's second Monte Carlo simulation. Mr. Miller is a Senior Vice President at SCA in operations and was formerly a Vice President of operations at ConocoPhilips. He is not trained as a geologist or geophysicist. His resume indicates his area of expertise is primarily human resources. *See* PX 67 (Miller Resume); PX 42 at attached exhibit 13. Nor does he have any relevant experience in the offshore Monterey region. He principally served to assemble the component parts of SCA's reports and forthrightly informed the court that he was not "an expert in the derivation of a recovery factor other than from a research perspective." Tr. 144. He testified that he had done research on prior conventional reservoir projects such as an offshore African field, but had not previously done so for any Monterey Field. *See* Tr. 145.

The product of Mr. Miller's research is the previously mentioned table of "Reported Monterey Recovery Factors." The majority of figures included were from reports produced for litigation in this case and its former companion case, *Amber Resources*. *See* PX 58 at 6 (10 out of the 12). One figure is from Dr. Ershaghi's paper, "A Conceptual Model for Reservoirs Producing from the Monterey Fields, Offshore California," and a second is from a Norcen 1989 report regarding Offshore California. The rest are from expert reports or other exhibits generated in the *Amber* litigation, mostly by Dr. Mannon, one by Dr. Ershaghi, and one from SCA's 2009 report in this case. *See id.* The lowest figure is a factor of 19-21 from the Jalama field in the Rocky Point Unit, derived in the *Amber* case. The highest figure, 143, is from the "chert zone" in the Hondo field. The 58 figure is from SCA's first report in this case. The number 58 was the "weighted average . . . derived from Dr. Mannon's 1996 trial report related to Gato Canyon." Tr. 141-42 (Miller).

Plaintiff points to the testimony of Dr. Mannon and Mr. Chapman who both stated that the Point Pedernales field was a good analog for the Gato Canyon field. When asked whether he used any fields as an analog for determining a recovery factor for the GCU, Dr. Mannon stated that he had been using "primarily" Point Pedernales. Tr. 1590. He expounded upon the reasons for that selection:

> Because in the terms of the requirements for analogy, it meets those requirements, I feel, very very well. It's approximately the same size in terms of the volume of oil anticipated to be produced. It's the same gravity. It's the same depth. The producing sections look very similar, as determined by Mr. Chapman. The fact that it's the same depth is that you have the same formation temperature, which is very important in terms of the effect of temperature on the viscosity of the heavy oil.
>
> So in terms of lithology, it's similar. In terms of the parameters, environment, it's very similar.

Tr. 1590-91. Mr. Chapman earlier testified that, "based on its depth and . . . lithology, based on its productive characteristics, it appears very analogous to [Gato Canyon]." Tr. 426. He acknowledged, however, that Point Pedernales was "geographically distant" from Gato Canyon and was not on the same "trend" as Gato Canyon. *Id.* Despite that, he believed that the rocks were "deposited [at the two fields] at the same time." *Id.* There is no further explanation or information regarding these lithological similarities contained in either of SCA's report nor any of Dr. Mannon's various reports regarding Point Pedernales or Gato Canyon.[23]

We are not convinced that Point Perdernales is a useful analog for the Gato Canyon field. Dr. Mannon's testimony suggests that the tail may be wagging the dog in his analysis. One of the reasons for his opinion that Point Pedernales was a good analog for purposes of figuring a recovery factor was because of its similarity in size "in terms of the volume of oil anticipated to be produced." Tr. 1590. The recovery factor is an input into the estimation of the ultimate recovery. Stating his reasoning another way, a factor in Dr. Mannon's estimates of the reserves in Gato Canyon was that Point Pedernales has a EUR similar to what he believes Gato Canyon contains. That is an assumption of the

[23] Dr. Mannon authored Defendant's Exhibits 56 and 70 along with Plaintiff's Exhibit 18 regarding the GCU. He produced Plaintiff's Exhibit 43 concerning Point Pedernales.

conclusion and not an exercise in reasoning. Dr. Mannon also stated that the oil gravity at Point Pedernales is the same as that of Gato Canyon. That statement is not supported by the evidence. Dr. Mannon reported that the oil gravity from Point Pedernales was 16 degrees API. Tr. 1642. The oil produced from the 460-2 well, the only well that flowed significant amounts of oil to the surface, tested at a much heavier 10-11 degrees API in all tested zones. DX 43 at 30-35 (results of drill stem tests from 460-2 well). Dr. Mannon testified on cross-examination that this difference in oil gravity "certainly would" affect the productivity expected from the GCU.[24] Tr. 1642.

Dr. Ershaghi testified that Point Pedernales was a poor analog to Gato Canyon for lithological reasons. He rejected Point Pedernales due to the dominance of quartz rock in productive zones. *See* Tr. 2402. Gato Canyon, by contrast, is "primarily dolomitically controlled." *Id.* Dr. Ershaghi compared Gato Canyon to a number of its neighbors and concluded that South Ellwood was the best analog. In comparing the results of mud logs between fields, he found that the rocks produced out of the South Ellwood field best matched those produced from Gato Canyon: "When you go to the South Ellwood and when you go to the Gato Canyon you see the limitation of the glassy shards. You see primarily the dolomitic section, so that's how you compare them."[25]

[24] Dr. Mannon made some attempt to discredit the results of the tests from the 460-2 well at trial. We do not afford that testimony much weight, however. Dr. Mannon reported much lower oil gravities in his pre-litigation reports to the owners. *See* DX 43 at 30-35; PX 18 at 6 (reporting an 10.8 degree weight for the 460-2 well oil and estimating 16 degrees for the whole field); *see also* DX 143 at (1989 Norcen Inter-Office memo noting Exxon's disappointment with the oil gravity at Gato Canyon). Defendant effectively showed that the lighter oil produced in several intervals in other tests was anomalous and due to contamination from diesel fuel pumped into the well to dilute heavier oil. *See* DX 277 (Chart of GCU Well Drilling); Tr. 1715 (Mannon); Tr. 2356 (Ershaghi).

[25] Plaintiff also propounded the Hondo field as a useful analog. Dr. Ershaghi's analysis of mud logs from the Hondo field showed similar results to that of Point Pedernales, meaning that it was not lithologically similar to Gato Canyon due to the predominance of quartz rock. *See* Tr. 2403. The Hondo field also benefits from a quantity of very light oil, which the operator uses to pump back down the well bore to dilute the very heavy oil present deeper in the formation. This allows for a greater production of otherwise difficult to produce heavy

Tr. 2403. Dr. Ershaghi further testified that quartz rock is preferable for oil production because the dominance of microfractures in the rock allows for greater storage and transport of oil, thereby increasing the productivity of a field, which would presumably at least partially account for the difference in recovery factor between Point Pedernales and South Ellwood.[26] Other relevant factors include oil gravity, distance from shore, and depth of the productive interval.

Plaintiff challenged Dr. Ershaghi's conclusion regarding the effect of dolomitic rock on the productivity of a field. Mr. Chapman conducted a study of mud logs from five wells at four different fields: Hondo, Point Pedernales, Gato Canyon, and South Ellwood. PX 93 at 15-15A. He concluded that it is dolomite rather than Chert (quartz) rock that is most prolific in the Monterey for oil production. Tr. 412-413; PX 93 at 15-15A. Included in the wells that Mr. Chapman examined are two from Point Pedernales. In both of those wells, one with an EUR of 15.1 MMbbl and the other of 7.1 MMbbl, dolomite was the dominant rock type. Plaintiff also pushed Dr. Ershaghi on cross-examination, presenting him with several studies conducted in the Monterey, which appear to indicate no preference for chert over dolomite for oil production.[27] Dr. Ershaghi did not attempt to deny the findings of these studies, other than to disagree that dolomite was as porous as chert, but did warn against drawing the conclusion that dolomite was as good or better than chert for oil production. *See* Tr. 2523-24. Dr. Ershaghi indicated that, despite the larger fractures that are present in dolomite, it is not better for oil production because those fractures

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oil.

[26] Dr. Ershaghi testified that the approximate recovery factor for South Ellwood is 20 BPAF. Dr. Mannon testified that the approximate recovery factor for Point Pedernales was 67 BPAF. Dr. Ershaghi testified that Point Pedernales and Point Arguello had recovery factors in the 40-50 BPAF range. In either case, that is a substantial difference from the recovery factor at South Ellwood.

[27] DX 153 at 21 (Appendix B-1 to Dr. Ershaghi's 2010 report, "Effect of Monterey Rock Compositon on Fracture Density"); PX 124 at 1, 4 (Union Oil Company report entitled "Orientation and Origin of Fractures in the Monterey Formation between Point Pedernales and Government Point"); DX 298 at 3, 8 (Report by Edwin Edwards and Ronald Heck: "Fracture, Fault and Fold Orientation From Formation Microscanner Data, Samedan OCS P-460 #2").

were often "choked" by the tight "matrix" of rock. *Id.* Quartz rock, by contrast, is more brittle and thus produces more microfractures, which Dr. Ershaghi testified were preferable for production.

Unlike Dr. Mannon and Mr. Chapman, we cannot conclude that the Point Pedernales field is the best analog for the Gato Canyon field. The fact that several wells on Point Pedernales may have a predominance of dolomitic rock does not change the circumstance that South Ellwood is litholigically more similar to Gato Canyon. Dr. Ershaghi's testimony that, on the whole, the rock at Gato Canyon is more similar to that at South Ellwood than Point Pedernales was not refuted. Point Pedernales is located in a separate basin, Santa Maria; Gato Canyon and South Ellwood are located in the same basin, Santa Barbara. South Ellwood is on the same trend as Gato Canyon. Gato Canyon has a much lower oil gravity than Point Pedernales. The depth of the productive rock and distance from shore do give us reason to think that Gato Canyon would have recovery factor above that of South Ellwood, however.

We also do not find the table produced by Mr. Miller and SCA bolsters the use of 58 recovery factor in any meaningful way other than to say that 58 lies somewhere in the middle of a range of handpicked figures. We allow for the unavoidable use of judgment and estimation in the mapping of the field and interpretation of the seismic data, and we do not find it unreasonable for plaintiff to have used a log normal distribution in its probabilistic calculations. The use of a 58 BPAF recovery factor is too high, however.[28] The evidence points to South Ellwood as a better analog, and Dr. Mannon's admission that the selection of Point Pedernales gets plaintiff to an ultimate number that supports its claim is telling.

Dr. Ershaghi's alternative median well approach provides some guidance to the court, and the selection of South Ellwood as an analog field is backed by lithological and geological reasons. It does fall short on one key point, however. The use of a median well figure improperly discounts the possibility of outlier producers that bring the ultimate recovery of a field up in a statistically significant way. All the experts agreed that there is tremendous variance in well production throughout the Monterey fields. As Mr. Cherry explained with respect to the statistical approach of the Monte Carlo simulation,

[28] We also do not reject plaintiff's estimates because it did not classify them under the PRMS system. We took it as a factor in weighing the evidence but not an independent reason to reject plaintiff's estimates.

the "difference between the mean and median is a function of having a log normal distribution where the values that occur out at the high end are very infrequent, but they do occur, and they have an impact on your expected ultimate recovery . . . ." Tr. 1333. Dr. Ershaghi's testimony that selection of a median number represents a well figure that is more likely to occur with any one well within a group of wells is unavailing. Defendant's approach improperly discounts the existence and influence of those high-side outliers in its estimate of reserves.[29]

We are left at the end of the day to make our best estimate from the two sides' presentations. Not having been offered a persuasive reason for selecting a particular recovery factor, we use MMS' general offshore Monterey factor of 40-50 BPAF, and adopt a figure closer to the 40 number due to the poor oil gravity evidenced from the 460-2 well, the similarities to the South Ellwood field, and that the fact that none of plaintiff's experts' reserve estimates were classified under the PRMS scale. A recovery factor of 40, being approximately one-third smaller than the 58 figure preferred by plaintiff, when applied to plaintiff's Monte Carlo results for the volume of the reservoir, produces a rough estimate of reserves of 60 MMbbl at the GCU.

Sixty million barrels is a not insubstantial figure and, based on plaintiff's evidence, there is a plausible scenario under which it could have made a profit from its 4.25 percent interest in that quantity of oil and attendant natural gas. It is necessary, therefore, to address the government's alternative arguments that there are independent shortcomings in plaintiff's proof of causation, namely, that plaintiff has not proved that the other owners would have gone forward with production, and that the owners could not have overcome the environmental restrictions on development. If either of those defenses is established, we need not consider in any detail whether Nycal would have realized a profit.

D. Whether the Owners Would Have Gone Forward

As an independent bar to recovery, the government argues that the

[29] In its post-trial brief, plaintiff performed a per well calculation using Dr. Ershaghi's methodology to account for future well production and the Gato Canyon advantages, but starting with the South Ellwood mean rather than median well figure for the base, and multiplying by the 22 well number from Dr. Mannon's 2001 report. This produced a sum of just over 73 MMbbl.

evidence is insufficient to establish with reasonable certainty that the owners would have proceeded to production of the GCU. The government believes that, without this piece of the puzzle established, plaintiff cannot prove that the breach caused a loss. If the GCU would not have gone into production, plaintiff has not lost any profits. Or, in the alternative, uncertainty about whether the owners would have gone forward to production means that it would be speculative to award damages to plaintiff. The key assertion in the government's argument is that it would have been necessary for an additional delineation well to have been drilled and for the results of that well to have been encouraging before a final decision would have been made to build a production platform. Its key evidence is testimony to that effect by relevant decision makers at Samedan.

Plaintiff concedes that a final decision on whether to build a rig and produce the field had not been made. That is not conclusive in plaintiff's view, however, because the events prior to the breach show a series of steps taken by the owners in furtherance of the ultimate goal of producing the field, making it more likely than not that it would have been developed. Plaintiff also disagrees with defendant's characterization of the importance of the results of an additional delineation well, pointing to the testimony of Ronald Heck that poor results from the 460-3 well would not have discouraged further development.

What we can say with certainty is that the 5000 BOPD results of the 460-2 well were encouraging. We believe it is clear that, with such a positive result in hand, the owners intended to conduct further exploration of the leases with the aim of developing the unit. The minutes from the owners' August 14, 1989 unit meeting are indicative of their intent at that time. The report of the minutes and attachments thereto contain a great deal of information about the 460-2 drill stem test ("DST") results and list the immediate steps that the owners intended to take at that time, namely acquisition and reprocessing of seismic data and the drilling of an additional delineation well on the eastern side of the unit. *See* DX 42. The initial time line from that meeting called for drilling of the delineation well sometime between 1993 and 1995. *Id.* at 59. The notes indicate that at least one owner, Norcen, expressed the desire to speed up that time line. *Id.* Amber Resources was noted as suggesting back-to-back well drilling if more than one additional delineation well was needed. *Id.*

In 1990, MMS granted a further lease suspension in order to allow the owners to drill the 460-3 well and perform another interpretation of the seismic data. Although no Authorization for Expenditure had been agreed to, the testimony of the individuals involved is that the 460-3 well would have been drilled. Samedan did not drill the well, however, because of the COOGER study, which began in January 1993. MMS suspended operations on all undeveloped leases for the duration of the study, which did not conclude until 1999.

At the conclusion of the COOGER suspension, Samedan and the other owners renewed their plan to drill the next well and submitted an updated lease suspension request to MMS along with a Project Description. Both of those documents included intended steps leading up to the spudding of the well. Mr. Heck, a consultant to Samedan, took the court through the steps that the owners contemplated in furtherance of their goal to drill another delineation well. He testified that the owners formed a committee of leaseholders, including leases in other units, to contract for the services of a semi-submersible drilling rig to drill several new delineation wells, including the well on lease 460. This was known as the Industry Rig Offshore California Committee. Tr. 855-56. An additional step necessary for drilling a well would be a shallow hazards study to look at certain environmental impacts of the delineation well. Mr. Heck testified that the air gun to shoot the seismic information "was on a truck heading out from Louisiana" and that a boat was identified to be retrofitted to handle the equipment. Tr. 721. The hazards study was interrupted by the district court's ruling in *Norton* and never took place.

As to the ultimate fate of the field in the owners' eyes pre-breach, Mr. Heck testified that the GCU had adequate reserves to support a decision to go into production even before drilling the 460-3 well. In his view, the next delineation well was more important for the placement of the oil rig than determining whether to produce the field. *See* Tr. 818. When asked what would have happened had one or two more delineation wells shown unfavorable results, Mr. Heck stated that, in his view, such a result would be unlikely. Nevertheless, "I still think we would have had an adequate reserve to go forward and recommend a development project."[30] Tr. 819 (Heck). He recognized, however, that he could not "tell . . . what the partners would have done for sure." *Id.* When pressed further as to the weight of his opinion regarding the viability of the project, he concluded: "I'm not sure, even though

[30] Mr. Heck was testifying as to the state of affairs prior to the COOGER study, around 1991. The facts did not materially change because of the COOGER-caused delay.

if we presented them with a project that could be developed, if it fit their economic models or not at that point in time, we never got there. So yes, that would be speculating on what they might think." Tr. 820.

Dr. Mannon also testified that he did not believe another delineation well was necessary for a platform decision: "I felt and I have stated that I felt that an additional delineation well was not necessary in terms of making a platform decision to move ahead, but I felt that it would be very helpful in terms of determining and maybe repositioning the location of the platform . . . ." Tr. 1519. He further stated that he gave this same recommendation to Mr. Heck and to the owners at one of the unit meetings in Santa Barbara. Coming out of that meeting, Dr. Mannon was summoned to a follow-on meeting with several individuals from Norcen concerning further information from the 460-2 well. He testified that, at the time, his impression was that there was a positive attitude towards proceeding to development of the unit. The weight of that testimony is, however, tempered by his directly preceding statement that "there was no indication that the . . . purpose of the delineation well was to validate the reservoir in terms of go or no go. They didn't share with me whether they had made a decision or not." Tr. 1522. He described his role in the process as "just kind of a hired hand" as an explanation for why he did not know whether a development decision had been made. *Id.*

We find that the owners were committed to drilling a third delineation well. The question remains, however, whether their commitment went any further. Plaintiff argues that the commitment to drilling the next delineation well, coupled with the results of the 460-2 well and the advice of Mr. Heck and Dr. Mannon, means that, by all industry standards, the GCU would have been produced. We decline to go so far, although we conclude that this shortcoming does not preclude plaintiff's claim.

We have the deposition testimony of Dan Dinges, who was a vice president and general manager of the business unit at Samedan responsible for all offshore California assets during the relevant time period. Mr. Dinges' testimony is the single most probative piece of evidence regarding the owners' intent to develop the GCU. Mr. Dinges was asked by defense counsel what the purpose of the 460-3 well was. His answer: "To gather additional information." JX 1 at 15. He was then asked whether this information was necessary to "make a development decision." *Id.* He replied "yes." Mr. Dinges, in fact, would not give the 5000 BOPD results of the 460-2 well an adjectival description when invited to do so. He described the result as merely "just one piece of information." *Id.* at 13. Mr. Dinges was further asked whether "Samedan was ready to go forward with or recommend going forward with full-blown development of the unit" after the 460-2 well. *Id.* at 19. "Not that I recall," was his answer. *Id.* He was then asked whether any other companies were prepared to go forward with development at that time. He answered that he was aware of none:

> Generalization, general comment that I can make is that we were going to continue on to gather information to be able to get to that decision, but we weren't there at the time. . . . I think additional information through drilling was necessary before final project sanction was necessary or was - not necessary, but capable.

Id. at 20. When asked hypothetically what options Samedan would have considered were the results of the next delineation well poor, Mr. Dinges listed two: drilling another well or abandoning the project. *Id.* at 27. After further questioning in this same vein later in the deposition, he added the options of "shooting additional seismic [and] reprocessing seismic [data]." *Id.* at 36.

Mr. Dinges was invited by plaintiff's counsel on cross-examination to clarify his statements regarding the owners' intent to develop the field:

> Q. Take a look would you, at [Samedan's 1999 suspension request], last sentence -- the last paragraph on the first page which reads: "During the time period of the SOP [suspension of production], Samedan proposes to drill another delineation well," and it gives the number. "The data will be used in final engineering design and preparation of the plan of development." Was it Samedan's intention to go ahead and propose a plan of development of the Gato Canyon Unit as of 1999?
>
> A. It would have been dependent upon the results.
>
> Q. Okay. But you certainly intended to continue on with the . . . plan to develop the field. Right?
>
> A. No, sir. With the plan to drill another delineation well.

Id. at 47-48.

Plaintiff points to the deposition testimony of Samedan employee Cam Countryman. Mr. Countryman stated that, as of 2000, Samedan was "very committed to drill additional wells and bring [the unit] to production if it drilled out the way they hoped it would." JX 2 at 29. Mr. Countryman's testimony regarding Samedan's intention to proceed with development of the GCU is less conditional than that of Mr. Dinges. Mr. Countryman admitted, however, that he did not know precisely what impact the results of the next delineation well would have. *See id.* 29-30. Mr. Countryman's testimony, although credible, is not as probative as that of Mr. Dinges with respect to Samedan's and the other owners' intentions regarding development of the GCU. Mr. Countryman began his involvement with offshore California projects in 1998. He was a "landman working offshore, responsible in helping run or oversee any of the land functions that needed to be dealt with in California as were brought down to me from upper management." *Id.* at 6. Mr. Dinges was Mr. Countryman's supervisor. Mr. Countryman testified that he had "very little contact with Dan [Dinges] on California. Very seldom did we discuss it. He [Dinges] handled most of the operations." *Id.* Mr. Dinges is the best source we have regarding the intentions of Samedan, and his testimony was unequivocal that a decision to develop the unit had not been made.

The documentary record from the owners and their consultants echoes the statements of Mr. Dinges. Minutes from the July 1989, May 1990, and January 1995 unit owners and representatives meetings all contain notes to the effect that the owners believed one or two additional delineation wells were necessary before a decision on development could be made. DX 43 at 58-59 ("It was agreed that at least one and possibly two delineation wells need to be drilled prior to a platform decision."); DX 44 (minutes from 1990 meeting); DX 111 (1995 meeting minutes); *see also* DX 727 (letter from Samedan to MMS); DX 80 (1999 letter from Samedan to Delta Petroleum Co.).

We thus find that it is uncertain whether the owners would have gone forward because the results of the next delineation well were not known. The question thus becomes whether that precludes plaintiff from advancing a lost profits claim. We think not. The reason we do not know whether the owners would have gone forward is that the breach prevented drilling of the delineation well. If the well had been very encouraging, we think it likely the owners would have gone forward. If the results were discouraging, we think they would not. If the results were inconclusive, it is impossible to say what would have occurred. We believe it unfair to burden plaintiff with the obligation to prove it more likely than not that the owners would have gone forward with production when the reason we will never know the outcome was the government's breach. In sum, plaintiff established that a delineation well would have been pursued. Beyond that, its obligation is limited to offering evidence of the volume of produceable oil. In other words, the best evidence of what a delineation well would have shown is our finding as to the reserves. If 60 million barrels of oil would have been attractive to the owners because it could be produced at a profit, plaintiff has established as much as it needs to about the likelihood that the owners would have gone forward.

E. Whether Environmental and Other Obstacles Would Have Prevented Development

Plaintiff has established that there were significant quantities of oil in the GCU and, therefore, that the owners would have pursued development if they could have been produced at a profit. It is unnecessary for us to address the economics of production, however, because we find that there were impediments unrelated to the breach which would have precluded development. First, plaintiff could not have obtained the necessary air pollution permits for the project from the Santa Barbara Air Pollution Control District ("SBCAPCD"), and, second, it could not have obtained access to the facilities at Las Flores Canyon to process the oil, gas, and water produced at the oil rig.

1. Emissions Permits

Exploration and development of offshore California leases requires regulatory approvals beyond those of MMS and unrelated to the reach of the CZMA. Particularly relevant to this suit are the environmental permits required by the SBCAPCD. Defendant urges the court not to assume that any of the various permits would have been granted and argues that it is unlikely, if not impossible, that the GCU owners could have met the requirements to garner these permits. This intervening cause would thus render the government's breach neither the "but for" cause nor a substantial factor in plaintiff's loss of profits.

In Santa Barbara county, offshore activities are subject to a cap on the amount of nitrous oxide ("NOx") and reactive organic compounds ("ROCs") that are emitted into the air. If an activity meets or exceeds the limit, it must offset all of its emissions back to zero. The amount of emission credits necessary to offset a project also depends upon where in the county the credit was purchased from.[31] Defendant's chief witness on the subject, John Peirson,[32] explained that Santa Barbara County is split into "air basins." The GCU is located in the South Air Basin of Santa Barbara County. South Air Basin credits can be used in a 1.5 to 1 ratio to offset emissions in the south basin. Credits from the neighboring North Air Basin offset at a much lower 6 to 1 ratio. Tr. 2018-19 (Peirson).

a. Delineation Well

Samedan planned to drill the next delineation well by utilizing a mobile drilling rig in conjunction with several other unit operators, known as the ORA group, to drill wells on several units. Mr. Peirson testified that the SBCAPCD intended to treat the wells drilled by the ORA group as one project, meaning that the entire project's emissions would be treated cumulatively and not on a well-by-well basis. Tr. 2005. This was echoed by Mr. Heck who stated that the county "preferred to view it as one project." Tr. 909; *see also* DX 39 at 2 (April 2000 letter from Samedan to MMS). Mr. Heck and Mr. Peirson both testified that the emissions limit for the mobile drilling project would be 25 tons of NOx and ROCs combined. The aggregating of emissions from all the wells to be drilled by the ORA group meant that they would have exceeded the 25 ton limit. *See* DX 39 at 2; Tr. 909-12 (Heck). MMS estimated in the draft 2001 EIS that the ORA group project would have a cumulative NOx emission of approximately 88 tons. DX 257 at 149. No other estimate was offered by either party. Using that estimate, the owners would have been required to offset 88 tons back to zero. Assuming they could purchase credits in the south air basin at the 1.5 to 1 ratio, 132 tons of credits would have been required. If only north basin credits were used, 528 tons would be required.

Samedan intended to avoid having its well aggregated with the other

[31] Emissions credits are created through projects and activities that ameliorate and/ or reduce NOx and ROCs levels in the air. Excess credits can be traded.

[32] Mr. Peirson has worked in the permitting of oil and gas projects for 32 years. He has been involved in projects in California since 1984, during which time he has worked on permitting nearly every unit currently in production in the offshore Santa Barbara area. *See* Tr. 1907-1919 (Peirson). His clients are both from the oil and gas industry and government regulators. We accepted Mr. Peirson as a highly experienced expert in permitting, including air pollution permitting of onshore and offshore California oil and gas projects.

ORA project wells by demonstrating to the SBCAPCD how the ORA project was different than an earlier well abandonment project that had been previously treated by the SBCAPCD as one project.[33] *Id.* If the owners could convince the county that each well to be drilled was a separate project, they anticipated that no single well would exceed the 25 ton limit. *Id.* Mr. Heck testified about the bases on which Samedan could have relied to show how the project was different. The prior project, known as "SWARS," involved the abandonment of 23 wells, whereas the ORA group project was only to drill three or four wells. Mr. Heck further explained, "it was our intent to make our case that these projects were geographically a great distance apart, whereas the SWARS project was in a very much smaller area, if that was a criterion." Tr. 984. Both projects involved the use of one mobile drilling rig moved from site to site, utilizing "big diesel engines" which produce the bulk of the emissions. Tr. 985 (Heck).

If the county stuck to its plan to treat the ORA group wells as one project, as it did with the SWARS project, the only avenue left for the owners would be offsets.[34] Tr. 1909-12 (Heck). Mr. Heck testified that the SWARS project had to create credits by paying into a fund "because there's seldom any offsets available, so you offset them with some project that creates offsets." Tr. 982. He recalled $750,000 as the amount required for the SWARS project. He further testified that the ORA group was aware that, failing to convince the county otherwise, it would likewise have to pay into this credit-creating fund. No other testimony or evidence was received concerning payments into a fund to create offsets.

b. The Gato Canyon Platform

Assuming that the owners had succeeded in getting permits for the delineation well, had completed delineation drilling, and made a decision to proceed with unit development, it would have been necessary to build and

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[33] In 1997-1998, a group of owners consorted to use a mobile rig to abandon some 23 wells in state waters: Subsea Well Abandonment Project, known as "SWARS."

[34] Mr. Heck also explained that the treatment of the SWARS project as a unitary project was the subject of litigation that resulted in settlement. The end result relevant here remains that the county treated it as one project and intended to treat the ORA project the same way.

install a permanent platform from which to drill wells and to which oil would be produced. As explained by Mr. Peirson, permanent developments, such as an oil rig, are subject to a stricter 10 ton per year limit for both NOx and ROCs (10 tons each). The parties disagree as to what emissions from such a platform would be. Mr. Peirson testified that the range of NOx emissions from the existing offshore rigs in Santa Barbara County is from 28 or 29 tons[35] at the Henry Unit platform to 350 tons at the larger Point Arguello platform. Tr. 2019-20. Mr. Peirson testified that the emissions from the Gato Canyon platform would be toward the lower end of that range but still above the 10 ton cap.

In addition, although not yet discussed in any detail in this opinion, it is likely that, in order to process the oil, gas, and water produced from the Gato Canyon platform, the owners would have been required to build an onshore processing facility. We further explore the likelihood of that project in the next section. Relevant at this point, however, are the likely emissions from such a facility. Mr. Peirson testified that an onshore processing facility would be added to the offshore platform for purposes of calculating emissions. The lowest emitting onshore processing facility in the area emits 8.7 tons of NOx and 45.2 tons of ROCs. Tr. 2035-38 (Peirson).

Plaintiff offered its own testimony in an attempt to rebut Mr. Peirson. Plaintiff suggested through its scheduling and permitting expert, Mr. Poulter[36], that certain steps could be taken to dramatically lower emissions from the project, such as using a fully electrified platform.[37] Plaintiff also argues that

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[35] Mr. Peirson later testified that the Henry platform emitted around "25 tons or so a year of NOx, and about 20 or 25 tons per year of ROCs." Tr. 2027.

[36] Mr. Poulter was accepted as an expert in the administrative and environmental permitting processes necessary to bring an oil field to production in the offshore California region. *See* Tr. 1275-79. He disclaimed, however, expertise in the area of air pollution permitting and stated that he would rely on consultants to assist him in this "very specialized area." *See* Tr. 1276; *see also* Tr. 1278.

[37] As explained by Mr. Peirson, a fully electrified platform is one that is powered by drawing electricity from the shore-based electrical grid as opposed to generating it on the platform or some stand-alone on-shore generation facility. No emissions are charged to the platform for power drawn from the

the emissions figures from the existing platforms are not very relevant because they were built some 20 or more years ago. Mr. Peirson testified, however, that the platform on the Irene unit, the only fully electrified platform in the area, emits approximately 58 tons of NOx and 30 tons of ROCs per year. Tr. 2027.

Plaintiff's more general argument is that, although air pollution permitting is a problem for owners and operators, "projects, such as offshore exploration and production, which require air pollution emission credits continue to be proposed in Santa Barbara, and that such proposal[s] are predicated on the assumption that the requisite air permits will issue." P.'s Post-Trial Reply Br. 133. Plaintiff's point to Mr. Peirson's response during cross-examination that his clients would not undertake new projects if there was no hope of permitting them:

> Q. In your experience as a permitting expert, would you put in an application for any kind of permit if there wasn't reason to believe that you could meet th emissions requirements?
>
> A. No.
>
> Q. You don't put in applications that are foregone losers, do you?
>
> A. I wouldn't think that's a smart thing to do.

Tr. 2170.

Plaintiff also offered a variety of possible offset-creating projects or emission-ameliorating activities ranging from retrofitting Santa Barbara county school buses with natural gas engines to transporting personnel to the platform using helicopters instead of boats. Neither Mr. Poulter, Mr. Peirson, nor anyone else, was able to quantify the amount of credits created by any of these

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grid. That does not mean, however, that a fully electrified platform has no emissions. For example, a platform normally has two cranes that are independently powered as well as back-up diesel generators for the drills and pumps. *See* Tr. 2027-28 (Peirson). Another source of emissions are the boats that shuttle men and supplies back and forth from shore.

hypothetical efforts, however. Mr. Peirson testified more generally that, based on his discussions with the head of the SBCAPCD, there was not a "substantial quantity left of offsets that you could create in the South Coast." Tr. 2172. He stated the same in his expert report. His conclusion was that "[o]ffsets in Santa Barbara County are very limited, or non-existent, and it would be very unlikely that offsets could be obtained for a source of this magnitude." DX 193 at 16. Plaintiff's scheduling expert Mr. Poulter, although not an expert in air pollution permitting, posited that one potential project would be to further retrofit the boats used to serve the San Ynez Unit. Those boats, however, had been previously retrofitted, which Mr. Peirson testified resulted in a 40 percent reduction of emissions at that time. He further informed the court that a similar 2002 project to retrofit the commercial fishing fleet in the area yielded a reduction of only 0.4 tons per year per boat. Although he did not state how many boats were retrofitted, he cited the fishing boat project as an example of how retrofitting boats was unlikely to result in any meaningful amount of credits.

In sum, we find that a reasonable range of platform emissions for the Gato Canyon platform, including those from a newly built processing facility, would be 34 tons of NOx and 60 tons of ROCs to 67 tons of NOx and 76 tons of ROCs. On the low end, that level of emissions would require combined NOx and ROCs offsets in the amounts of 156 tons using all South Basin credits or, using North Basin credits, 624 tons of offsets. On the high end of the range, 214 tons of combined credits from the South Basin or 857 credits from the North Basin would be required.

c. Available Credits

The evidence leads us to the conclusion that the owners would have been unable to significantly ameliorate emissions through electrification or other means. The only option then would have been to purchase credits from other sources. Mr. Peirson explained that emissions credits are tradeable. "And then once you buy it, you now own the certificate, and then you turn it into the district, and say here is my credit for my project." Tr. 2013 (Peirson). Mr. Peirson told the court that, as of the time of trial, there were approximately 30 tons of NOx offsets and 5 tons of ROCs offsets existing in the South Air Basin. There were 150 tons of NOx offsets and 70 tons of ROCs offsets existing in the

North Air Basin.[38] Tr. 2015-16 (Peirson); DX 1002 at 13. Those credits are, for the most part, unavailable, however. Mr. Peirson explained that, in the North Basin, most credits are held by Vandenberg Air Force Base and "are not available to be purchase or traded." Tr. 2016. In the South Basin, "Plains Exploration owns a lot of the South Coast NOx emission, and they are not on the market." *Id.*

Even giving the owners all of the possible favorable assumptions of a fully electric platform, a low-emitting processing facility, no emissions from construction, and that Samedan could have purchased all of the credits in the inventory, not just those available, the owners would have been well short of the credits needed for rig operation and the ORA group drilling. We note that Mr. Peirson's testimony about number of credits available was based on SBCAPCD's current inventory and not the credits available at the time that plaintiff contends that the platform would have been installed and begun operating. We do not believe, however, that the numbers would have been meaningfully different. Mr. Peirson was still confident in his conclusion that it would have been highly unlikely that the GCU owners could have obtained the needed credits. We agree. Plaintiff has not proven that the breach was the cause of its lost opportunity to explore and develop the leases. The owners' inability to obtain air pollution permits was an intervening cause of the lost opportunity to develop the lease.

Plaintiff's answer that time and money would eventually provide a solution to the permitting dilemma does not overcome the problem. Instead, it creates a new one for plaintiff: uncertainty as to damages. In order to calculate damages, we have to have a reasonable basis for estimating costs, as well as the timing of when those costs would have been incurred. Conjecture that, "we would have come up with a solution, although we don't know when, or what it would have cost"' injects an intolerable level of uncertainty into calculating damages. Plaintiff's burden is one of reasonable certainty. Accepting on faith that, given enough money and time, the owners could have eventually obtained the necessary permits means we cannot rely on plaintiff's schedule of development, nor would we know how much it would have cost to build and operate the various facilities. Plaintiff's costs are not reasonably certain without a set time line. Likewise, we do not know how much additional cost would have been incurred in order to create or obtain credits.

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[38] Santa Barbara County publishes a list of emissions credits in its inventory on its website.

For example, Mr. Heck's testimony that plaintiff could pay into a fund for emission-reducing technology, similar to the SWARS project, is merely an abstraction. We do not know whether such a project would have been available for the Gato Canyon project or how much it would have cost. Mr. Peirson opined that purchasing credits, assuming availability, would have cost approximately $50,000 per ton. *See* DX 193 at 16-17. That would have added, for the platform alone, an additional $7.8 to $11 million dollars using all South Air Basin credits, and, if only North Air Basin credits were purchased, $31.2 million to $42.85 million dollars. In short, if we overlooked the permitting problems by assuming a solution, we would be unable to quantify damages with any degree of certainty.[39]

The federal government's actions are thus not the reason the owners ultimately would have been unable to proceed.[40] Plaintiff's inability to demonstrate that it is more likely than not that it would have obtained the necessary environmental permits is thus an independent basis for ruling that it cannot establish lost profits. Nevertheless, the government offers one additional and potentially independent ground for breaking the causation chain, which we address below.

2. Processing Facility

The owners faced another major obstacle to the development of the GCU: the need to process the oil, gas, and water produced from the platform. There are three existing processing facilities in Santa Barbara County. One of those, Exxon's facility at Las Flores Canyon, was within reach by pipeline from the GCU. The Las Flores facility was designated by the county as a "consolidated" site, meaning that the county intended for the site to be used by multiple operators to process their oil, gas, and water. It was owned entirely by

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[39] We explain below that, while it is theoretically possible that plaintiff could have built a new processing facility at Las Flores, the costs of such a facility would have been very high. Even though we are unwilling to rule out the possibility it could have obtained a site, as we explain below, construction of a new facility would multiply the unknowns as to cost.

[40] Plaintiff suggests in its reply brief that such a result would amount to an uncompensated taking. This was a theory not put forward in the complaint or at trial. In any event, the relevant actor would have been the state or the county.

Exxon, however. The only other option was construction of a new site not already in use as a processing facility. That, however, would be subject to a public referendum in the county and was never considered by Samedan as a viable option.

Samedan's hope was to process its oil, gas, and water at Exxon's Las Flores facility by utilizing existing capacity. *See* DX 52 at 233 (2000 GCU DPP). As a condition of Exxon's permits for the Las Flores facility and in conjunction with the county's designation of Las Flores as a consolidated site, Exxon was required to provide "equitable access" to the site. The full import of that language was not meaningfully explored at trial. What is known is that Exxon had some obligation to allow the use of its existing facilities or the unused land at the site for construction of a new facility. Two questions thus follow: whether the existing Las Flores facility had the available processing capacity to accommodate the GCU production and, if not, whether it would have been feasible and practicable to build a new facility at the site.

a. Samedan Would Not Have Been Able to Utilize Existing Capacity at Las Flores to Process its Oil, Gas, and Water

It is clear from the trial testimony and documentary evidence that Samedan's preferred option for processing was to use existing capacity at Las Flores. Defendant challenged that option by eliciting testimony and producing several documents relating to two unsuccessful attempts by other operators to use the existing Las Flores facilities for processing oil, gas, and water.

The chief evidence presented by defendant on this issue centered around an unsuccessful attempt to utilize Las Flores as a processing site by another operator, Veneco. Veneco explored using Las Flores to process oil and gas produced from Platform Holly in the Ellwood Field. In 2008, Exxon reported that its facility was permitted to handle 140,000 barrels of liquid per day, with a design capacity of 100,000 BOPD and 75,000 barrels of water per day.[41] DX 944 at 4 (Exxon comments on Veneco Ellwood Full Field Development Project Draft Environmental Impact Report). Exxon processes only 38,000 BOPD due to the high volume of water processed. Exxon planned to increase its water

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[41] Oil and water are produced from the wells as a mixed emulsion and, if not separated on the platform, are transported to a processing facility in that condition.

processing capability, but it forecast that it would utilize all of that future capacity itself. The following table appears in the comments to the draft environmental report ("EIR"):

LFC Liquids	Design Capacity	Current Operations	Future Operations	Holly Production (estimated)	Comments
Total Emulsion [kbbl/day]	140	103	130	19	Venoco processing would exceed total fluid . . . capacity
Total Oil [kbbl/day]	100	38	40	19	
Total Water [kkbl/day]	75	~65	~90	0*	*Water separation would occur at platform Holly

Id.

As to gas processing, Exxon was permitted to process 75 million standard cubic feet per day ("MMSCFD") at Las Flores. It was, however, "not always [able] to operate at the permitted maximum rate due to operational and production limitations." *Id.* at 2. In 2008, Exxon was operating below the permitted limit but at capacity due to mechanical limitations. Exxon further noted that the gas produced from Ellwood was much more acidic than the gas that the Las Flores facility had been built to process, meaning that one unit of Veneco gas would take up over three units of Exxon's processing capacity at Las Flores.

Exxon's conclusion was that its "future operations may be able to accommodate additional oil from a third-party Operator, but we are limited as to any additional water and gas processing capabilities." *Id.* at 4. Exxon stated that, although Venoco planned to separate water at the platform, additional "final water polishing" would likely be necessary "in order to meet oil pipeline sales quality specifications." *Id.* Further, "[u]nder current EPA NPDES General Permit requirements, there is a likely permit issue with the commingling of State and Federal produced waters within our oil and water processing facility."[42] *Id.*

Exxon's statement of the problems surrounding any attempt to utilize its spare capacity in 2008 and for the foreseeable future were echoed in Venoco's own comments to the Draft EIR, *see* DX 223 at 9-17, and by defendant's expert, Mr. Peirson. Mr. Peirson explained that using Las Flores was an alternative plan in Venoco's proposal. Venoco's preferred solution was to process its oil and gas at its own existing Ellwood facility. He explained, however, that such would be a "non-conforming use in the city of Goleta," which meant that Venoco faced a problem permitting the project. Tr. 1973. Venoco agreed with Exxon's conclusion that the existing Las Flores facilities could not handle the oil and gas production from the Platform Holly project. *See* DX 223 at 10.

Plaintiff views the import of Exxon's conclusion that it was limited as to future processing of third-party produced water as having to do primarily with the issue of commingling state and federal water, which would not be an issue at the GCU. Even if Exxon did not have the future water processing capacity needed, plaintiff believes that Venoco's estimate of $15 million for a 10,000 BOPD water-oil processing facility to be a reasonable baseline from which to support Dr. Mannon's cost estimate of $36.15 million for a larger onshore treatment facility.

As to gas processing, plaintiff points out that its gas is not as acidic as that which would have been produced from the Ellwood Field, and thus it would not face as large a hurdle in that regard. Plaintiff extrapolates from Exxon's table at page three of its 2008 comments on the draft EIR that Exxon had future capacity of approximately 20 MMSCFD. The table lists the design capacity for the two separate gas processing facilities in the Canyon as 75 and

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[42] Venoco's Ellwood Field produces from state waters and Exxon's Santa Ynez Field produces from federal waters.

21 MMSCFD respectively.[43] *See* DX 944 at 3. It lists future Exxon operations as requiring 65 and 11 MMSCFD. *Id.* Plaintiff thus derives a spare capacity of 20 MMBSCFD. The relevant part of the table appears below:

Gas Processing	Design Capacity	Current Operations	Future Operations	Venoco Requirements (Estimated)	Comments
Gas [MMscfD]	75/21	55/11	65/11	20	. . .

Id.

Plaintiff's most recent estimate of its gas production at Gato Canyon is 4.314 BCF of gas per year, which is equal to a daily production of approximately 12 MMSCFD. *See* PX 47 at Table A. Mr. Peirson's report lists gas production at Gato Canyon at about 52 MMSCFD, which appears to be based on an earlier estimates by Dr. Mannon. The revised 12 MMSCFD figure is well within plaintiff's reading of Exxon's 2008 estimates of its future available gas processing capacity. As to oil, Dr. Mannon testified that, based on his approximately 91 MMbbl ultimate production estimate, peak production at the GCU would meet or exceed 30,000 barrels per day. Tr. 1543-44.

The 2008 date of the Venoco and Exxon comments to the Draft EIR makes those documents particularly relevant to our consideration of these same issues in this case. Dr. Mannon's 2010 report uses 2007 as the date of initial production. Under plaintiff's schedule, propounded by Mr. Poulter, production from Gato Canyon would not have begun until 2009. Mr. Peirson, for defendant, estimated a 2012 start of production. Under any of these scenarios, the evidence concerning Exxon's processing capacity and estimate in 2008 of future capacity is very useful in reaching our conclusion.

Plaintiff did not elicit any testimony or produce any documentary evidence to rebut the conclusion that Mr. Peirson drew based on his study of Venoco's and Mobile's prior unsuccessful attempts to use Las Flores as a processing site. In its post-trial briefing, plaintiff largely shrugs off the issue, arguing that defendant misread Exxon's letter to Venoco and "totally missed the

[43] The Las Flores Canyon site holds two separate gas processing facilities. One is known as POPCO and the other as the Las Flores Canyon facility.

point" as to the evidence relied on by Mr. Peirson. Pl.'s Reply Br. 94.

Plaintiff instead makes the argument that the letter from Exxon is more properly viewed as a negotiating tool used by Exxon to exact a maximum payment from Venoco, rather than an absolute statement of no future spare capacity. Plaintiff seizes upon Exxon's statement that it intended to increase future water processing capabilities and also points to an internal Norcen memo, dated May 1, 1989, in which Norcen discusses permitting and onshore processing as they pertain to offshore California development as a whole and particularly to the GCU. The memo notes the development of the Las Flores facility, which was scheduled, as of the time of the memo, to go online in 1992. The memo states that "Exxon is receptive to processing other production if spare capacity exists." DX 143 at 3. The memo predicts that spare capacity will not exist "until several years after start-up of the plant when production for the Santa Ynez unit starts to decline." *Id.* One of Norcen's conclusions was that Exxon would be open to allowing "flow through the Hondo pipeline as long as it would not hinder their operations at the Santa Ynez unit."[44] *Id*. at 4. Thus, in plaintiff's view, the question of utilizing Las Flores is one only of cost.

We find that plaintiff would not have been able to utilize existing Las Flores facilities to process its oil, gas, and water. We take Exxon's statement of its then existing capacity at face value and not as a negotiating stance as plaintiff would have us. Venoco's comments to the draft EIR are telling in that they accepted Exxon's statements as truth. Venoco concluded that Exxon did not have spare capacity at Las Flores to handle its gas and water processing needs. Venoco was not successful in gaining access to Exxon's existing processing facilities and instead considered building its own facility at Las Flores. Samedan would have had to consider the same.

Exxon reported the ability to handle up to 140,000 barrels of liquid per day, which included up to 100,000 barrels of oil and up to 75,000 of water. Exxon explained that, as the Santa Ynez field matured, the water to oil ratio in the emulsion produced from the rig increased, which meant that the facility was already operating at near its water processing capacity. As the table on page 4 of Defendant's Exhibit 944 shows, Exxon believed it would exceed its existing water processing capacity in the future. Exxon concluded, and Venoco accepted, that Las Flores could not handle Venoco's 10,000 BOPD production

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[44] The Hondo pipeline brings oil, gas, and water from the Santa Ynez unit onshore to Las Flores.

even when assuming that water and oil would be separated by Venoco at the platform. Samedan did not propose to separate its oil from water at the platform. Needless to say, 30,000 barrels of oil, unsegregated at the platform, would have greatly exceeded Exxon's spare capacity. Even if we reduce that peak daily production in half to over-accommodate our holding regarding the reserves at the GCU, it would have exceeded the spare capacity at Las Flores.

There is ambiguity concerning Exxon's capacity to process natural gas at its facilities at Las Flores. Taken alone, the excerpt of the chart copied above would seem to indicate that the Las Flores Canyon facilities would have the necessary spare capacity to handle Dr. Mannon's most recent estimates of 13 MMSCFD for the GCU. Exxon qualified the chart, however, with this language that directly precedes it:

> ExxonMobil, currently and for the foreseeable future, operates a continuous rig line, and drilling new wells to produce oil and gas to effectively manage the reservoir and field life. As shown in the table below, current and future gas processing operations will be at or near design limits without consideration for Venoco's processing requirements.

Id. at 3. Exxon also stated earlier that it was, at that time, operating below permitted limits due to mechanical complications, and, although it planned to remedy those limitations, it would at some future point begin processing gas currently stored in well bores offshore and not yet brought to shore. *See id.* at 2. Whether that additional gas is included in the estimates for future operations in the chart on page three of the exhibit is not clear. We take Exxon at its word, however, that it did not anticipate being able to accommodate future gas processing, especially in light of its need to process gas that it was then storing offshore. Venoco's comments to the draft EIR indicate that it tried proposing an alternative scenario in which it sent a lower volume of gas to Exxon to be commingled with its processing at Las Flores. Exxon answered that it had "re-confirmed [its] earlier assertion that such capacity does not exist." DX 223 at 10. We conclude, as Exxon did, that "future operations may be able to accommodate additional oil from a third-party Operator, but [Exxon is] limited as to any additional water handling and gas processing capabilities." PX 944 at 4.

In sum, plaintiff has not demonstrated that it is more likely than not that it could have utilized Exxon's existing facility for on-shore processing.

Plaintiff offers one other option: construction of a new facility at Las Flores.[45]

b. Plaintiff Could Not Have Built a New Facility at Las Flores

Samedan would have been forced to try to build its own facility at Las Flores or seek processing elsewhere. There are two problems with this proposed solution, however. We have already examined one. We find that the SBCAPCD would have aggregated the emissions from an onshore facility with the emission from the offshore platform. Samedan thus would have been unable to garner the necessary air pollution permits due to the lack of available emissions credits in Santa Barbara County. In other words, a new facility would simply have added to the virtual impossibility of obtaining the necessary permits.

The second difficulty, although perhaps not an insuperable obstacle, is that construction of a new facility at Las Flores adds to the uncertainty of the costs of going forward. This requires a closer examination of plaintiff's proposal, as well as Venoco's earlier efforts to build at Las Flores.

Recognizing its requirement to provide "equitable access," Exxon offered to "provide property for co-location" of an additional oil and gas processing facility at Las Flores Canyon should Venoco decide to pursue this "alternative siting." DX 944 at 1. Venoco considered this option and detailed its consideration, primarily of cost, in its comments on the draft EIR.

Venoco concluded that it would need to build a facility capable of processing 10 MMSCFD of gas and 10,000 BOPD, along with water utilities such as boiler feedwater, steam, and firewater, a new power service, oil tankage for incoming and outgoing emulsions, and an offshore pipeline. In additional, Venoco would have to procure on the order of 15 to 20 acres from Exxon, upgrade power cables, and make certain upgrades to Platform Holly. *See* DX 223 at 11-15. A chart appears at page 15 of Venoco's comments on the draft EIR, which summarizes and categorizes its cost estimates for such a project if

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[45] In its briefing, plaintiff also mentioned that it was not foreclosed from seeking some unspecified alternate site at which to process its oil, gas, and water. This was not explored at trial in any way, however, and we do not consider it an answer to the problem of processing at Las Flores raised by defendant.

built in 2008 or 2015. *See id.* at 15.

2015 was the date Venoco estimated by which it could complete construction of such a facility. In 2008 dollars, Venoco estimated a total cost of $223,513,000, which, if actually completed in 2015, Venoco estimated to be $458,201,000. No agreement between Exxon and Venoco was ever reached, and, according to Mr. Peirson, Venoco recently withdrew its application to develop the field.

Mr. Peirson also informed the court of one other attempt to gain access to the Las Flores canyon in the 1990s. Mobil Oil, before it merged with Exxon, attempted to gain access to Las Flores. After negotiations with Exxon, Mobil ultimately concluded it was too expensive, at least in part because Exxon demanded "payment of costs associated with Exxon's original building facility costs." DX 193 at 20. Although not discussed in any great detail during the trial or in the Mr. Peirson's report, it is some evidence of the prohibitive costs associated with attempting to utilize Exxon's Las Flores facilities. Mr. Peirson concluded that he did not believe that Samedan would have had any more success in utilizing Las Flores than either Venoco or Mobil did.

If plaintiff had found it necessary to build a new facility at Las Flores, it would have had to adjust its proposed schedule. The one it offered at trial assumed production beginning in March of 2009. Mr. Poulter, who authored the schedule, posited the following key dates:

1. Samedan would submit the modified EP in September of 2001;

2. Samedan would have completed the delineation well by the end of December 2003;

3. The DPP would have been approved by the end of June 2007;

4. Initial production begins no later than the end of March 2009.

PX 54 at 20 (Poulter expert report). There is no line item in the schedule specifically for constructing onshore facilities. The final item before production is listed as "Construction of Project Facilities." *Id.* The construction phase was slated to begin the third quarter of 2007 and last until production began, a duration of one and a three-quarters years.[46] Although plaintiff argued that it would be able to build its own onshore facilities at Las Flores if necessary, it did not explain when it would begin and how long it would take. The only piece of evidence that we have on the question comes from Venoco's analysis of construction of onshore facilities. Venoco concluded that: "It is likely that time to design, permit, and construct a process plant on this order will take a minimum of 7 years. Construction itself is expected to take 1.5 years." DX 223 at 15. The actual time to construct would fit within plaintiff's window for facility construction. The other necessary steps of design and permitting, however, add significant amounts of time and doubt as to when the project could proceed.

Presumably plaintiff would answer that the design and permitting processes could and would have begun well before the 2007 beginning of construction. All else being equal, that is true. Nevertheless, in a world in which so many contingencies are relevant to the decision to move forward with development of the lease, the question of when that process might have begun is a difficult, if not impossible, one to answer. We find it unlikely that the owners would have undertaken any major expense in pursuit of an onshore facility before the results of the third delineation well were known. The testimony of Mr. Dinges recited previously in this opinion makes clear that development beyond the next delineation well was not yet decided on at the time of breach. Giving plaintiff the benefit of the doubt, presuming favorable results from the third delineation well and that a decision by the owners would have then been made to move forward to production, Samedan would only then have begun the process of seriously inquiring whether Exxon would have spare capacity and entered negotiations. At what point Samedan would have emerged from those negotiations is unknown. If it was unsuccessful, only then would Samedan have begun to consider building an onshore facility.

In addition to the impact on plaintiff's damages schedule, the need to build a new facility adds uncertainty to its damages model. Venoco concluded that constructing its own onshore processing facilities at Las Flores would cost

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[46] Defendant disagreed with plaintiff's schedule and proposed its own competing schedule through its expert, Mr. Peirson. That schedule called for the platform to begin production in 2013. We need not decide which is the more likely scenario because, as we explain more fully below, the complications of building an onshore facility casts significant doubt as to plaintiff's schedule.

$223,513,000 in 2008. Defendant's expert on cost and associated issues, Mr. Richard Miller, used the Venoco calculation as a basis for his own estimate of a $125 million dollar cost for the GCU facility at Las Flores. The reduction in cost resulted from zeroing out those costs that would not have been incurred by the GCU owners, such as modifications to the platform that the GCU platform would not have needed.[47]

Plaintiff adopted the cost estimates of Dr. Mannon in making its calculations of economic feasability and profitability. Dr. Mannon assigned $38.7 million in costs for Las Flores onshore facilities. *See* PX 47 at 11 (Mannon expert report); PX 80 at 3 (Valuation of 100 percent working interest of GCU).[48] Dr. Mannon based his estimate on the costs to build onshore facilities for the Point Pedernales field at the Lompoc location, which is operated by Unocal. Dr. Mannon made use of historical operating costs "for the years 1987-1993 furnished by Unocal as operator of the Pt. Pedernales Unit." PX 47 at 10. Based on Dr. Mannon's understanding of those costs, he believed that a "$30.00MM plant cost in 2001 would be more than adequate." *Id.* He then escalated those costs to $36.15 million to account for a 2007-2008 time frame for construction of the facility.

We find Richard Miller's estimate of the cost of construction of a new processing facility at Las Flores to be more reliable. Mr. Miller based his estimates on the in-depth analysis performed by Venoco in 2008 as outlined in its comments to the draft EIR. Venoco's analysis is more relevant as to when the cost items were estimated: 2008 (Venoco) versus 1987-1993 (Unocal). Venoco's estimates are also specifically associated with a project at Las Flores Canyon similar in scope to what Samedan would have had to undertake. The scope of the Unocal facilities is unknown. We do not know whether Unocal had to negotiate with a third-party for access to the Lompoc site, as Venoco had to and Samedan would have had to, nor do we know the relative size and capacity of the Lompoc site as compared to the needs of Samedan at Las Flores.

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[47] Mr. Miller did not specify which costs he reduced or eliminated in drawing his estimate from Venoco's.

[48] There is a minor disagreement between the two documents. In his report, which is a valuation of plaintiff's interest, Dr. Mannon states that the onshore facilities would cost $36.15 million. In the schedule of costs associated with the 100 percent valuation of the GCU working interests, the cost is listed as $38.7 million.

Richard Miller, on the other hand, specifically stated that Venoco's proposed facilities were a reasonable analog for those that Samedan would need. *See* DX at 29. We agree.

In sum, the most likely scenario facing the owners was an additional cost of approximately $125 million and an unknown additional amount of delay on top of the uncertainty generated by the costs of buying pollution credits. While this degree of imprecision might otherwise seem to doom any certainty as to damages, it is unnecessary to reach that result, as our finding that a new facility would not have been permitted is sufficient to preclude the necessary finding that the breach caused damages.

IV. Summary of Findings

We find that it would have been foreseeable to government officials that breach of the lease agreement could result in significant lost profits of the type claimed here. We also find that there were approximately 60 million barrels of oil in the reservoir. Plaintiff, has not, however, proved that the breach was the proximate cause of any loss under either standard for causation. Instead, defendant established that an intervening cause, for which the United States was not responsible, would have precluded development of the GCU: an inability on plaintiff's part to obtain the necessary air pollution permits for its delineation drilling, its permanent oil rig ,and its associated onshore processing facility. The number of credits necessary to permit the oil platform itself are beyond those which exist, let alone which might be available for purchase. Plaintiff was unable to rebut this overwhelming evidence.

It is therefore unnecessary for us to determine whether plaintiff could have obtained the necessary financing to participate in the further exploration and development of the leases. Nor is it necessary for us to determine how much money plaintiff would have earned if the unit had gone into production, what the time line for production would have been, or whether damages could even be calculated with the necessary degree of certainty.

CONCLUSION

Plaintiff has not proven its entitlement to lost profits and has abandoned restitution as remedy. Accordingly, the clerk of court is directed to enter judgment for defendant and dismiss the complaint. No costs.

s/ Eric G. Bruggink
ERIC G. BRUGGINK
Judge