

UNITED STATES DISTRICT COURT
EASTERN DISTRICT OF LOUISIANA

SOUTHERN OIL OF LOUISIANA LLC * CIVIL ACTION
VERSUS * NO. 21-2337 c/w 23-131
ALLIANCE OFFSHORE, LLC, ET AL * MAG. JUDGE CURRAULT

DOCUMENT RELATES TO ALL CASES

**PHASE II
(DAMAGES)
FINDINGS OF FACT AND CONCLUSIONS OF LAW**

These consolidated matters were referred to the United States Magistrate Judge for all proceedings and entry of judgment in accordance with 28 U.S.C. § 636(c) upon the written consent of all parties. ECF Nos. 39, 58.

The cases arise from a vessel's nighttime allision with an unlighted fixed well platform in the Gulf of Mexico. The Court granted bifurcation and ordered that trial proceed in two phases: (1) liability, including exoneration or limitation of liability and apportionment of fault, and (2) damages. ECF Nos. 77, 127. The Court held the Phase I trial, without a jury, on July 22-23, 2024. ECF Nos. 162, 163. The Court issued Findings of Fact and Conclusions of Law on August 20, 2024, and entered Judgment on September 17, 2024, finding that the negligence attributable to Southern Oil of Louisiana, LLC and to Alliance Offshore, LLC/Captain Christopher Tyndall were both proximate causes of the December 2, 2021 allision, with fault shared equally (Alliance being liable for 50% of the damages and Southern Oil being liable for 50% of the damages), and that Alliance's failure to train Capt. Tyndall rendered his negligence within its privity or knowledge, thereby precluding limitation or exoneration. ECF Nos. 172 at 42-43; 178.

The Phase II (damages) trial proceeded on March 11, 2025. ECF No. 201. At the beginning of the trial, the parties introduced Joint Exhibits J-83 through J-87, Plaintiff's Exhibits SO-10 through

SO-29, and Defendant's Exhibits A-1 through A-3. *Id.* The Court admitted all of the listed exhibits and heard testimony from the following witnesses: (1) Louis Belanger; (2) Ryan Landry (by deposition); (3) Donald Olson; and (4) Harvey Kelley. *Id.*

Having considered the evidence adduced at trial, the record, the testimony of the witnesses, the arguments and written submissions of counsel, and the applicable law, the Court makes the following findings of fact and conclusions of law pursuant to FED. R. CIV. P. 52(a). To the extent, if any, that any of the following findings of fact constitute conclusions of law, or vice versa, they are adopted as such.

I. FINDINGS OF FACT

This Court's Phase I Findings of Fact and Conclusions of Law are incorporated herein by reference. ECF No. 172.

1. The Corvus Well is located in the Gulf of Mexico in the Breton Sound field, near Main Pass. It was drilled in 2006 and placed in production on January 11, 2007. Ex. SO-10, 26. The MP45 Corvus/SL 18550#1 Well and Platform (the "Well") consists of a metal caisson, a two-level metal platform, a boat dock, and an access ladder.

2. On December 2, 2021, at approximately 12:30 a.m., the M/V MR. CADE allided with the unlighted Well. The allision caused physical damage to the platform structure, which required that the Well be shut-in during repairs, but did not result in any spill or physical loss of hydrocarbons from the reservoir. The allision also caused physical damage to the M/V MR. CADE.

3. To repair the physical damage to the platform structure, which was conducted over a 108-day period from December 2, 2021, through March 20, 2022, Southern Oil spent \$1,134,109.39. Exs. SO-10 at 86-87; SO-26 at 87-89; ECF No. 194, PTO ¶ 7, No. 1 (stipulation). In light of the parties' stipulation to this amount, the Court concludes that Defendants shall pay to Southern Oil that amount, as adjusted by the percentage of fault attributed to Southern Oil.

4. The parties also agree that the M/V MR. CADE underwent repairs over the course of 67 days until it was able to return to service. ECF No. 194, PTO ¶ 7, No. 3. They have also stipulated that Alliance spent \$462,242.52 to repair the physical damage to the M/V MR CADE. *Id.* at No. 2. In light of the parties' stipulation to this amount, the Court concludes that Southern Oil shall pay to Defendants that amount, as adjusted by the percentage of fault attributed to Defendants.

5. The only issues in Phase II are the disputed amount of damages Alliance claims to have incurred due to loss of use of its vessel(s) during the 67-day repair period and the amount of damages Southern Oil claims it has incurred, or will incur, as a result of delayed/lost production associated with the 108-day shut-in during repairs caused by the allision.

6. The Court heard expert testimony from two witnesses, Whitney Belanger Jr. (Southern Oil's expert) and Donald Olson (Alliance's expert), and additional testimony from Ryan Landry (via deposition) and Harvey Kelley.

7. The Court accepted Southern Oil's expert Whitney Belanger Jr. as an expert in the area of petroleum engineering, including reservoir engineering, hydrocarbons production, hydrocarbons markets reservoir analysis, production forecasting and the economic analysis and forecasting of hydrocarbons production. Mr. Belanger has worked as a petroleum engineer since 1984, and he first started working on the Well in 2009, preparing reserve estimates. Test. of Belanger. Approximately 40%-50% of his work is for Southern Oil. *Id.*

8. The Court accepted Alliance's expert Donald Olson as an expert in petroleum engineering with a focus on reservoir and petroleum engineering. Mr. Olson did not prepare an independent economic reservoir analysis; rather, he studied the fluids in the reservoir, opined on the Well's performance, and criticized alleged errors and deficiencies in Mr. Belanger's opinion. Test. of Olson. Mr. Belanger used to work for Mr. Olson. *Id.*

A. Southern Oil's Damages

9. Both experts explained that a Well's life span is based on the economics of the operation required to remove the hydrocarbons from the reservoir. Production ceases when the operational costs begin to exceed the revenue generated from ongoing production. Thus, while hydrocarbons will remain in the reservoir, production ends when it is no longer economical to retrieve the hydrocarbons from the reservoir. For that reason, continued operation depends not only on the operational cost to retrieve the hydrocarbons but also on the available market price that may be obtained for the hydrocarbons. As prices rise, the operational life of the reservoir is extended. As prices fall, the operational life of the reservoir is decreased.

10. After the Well began production in 2007 and for several years thereafter, it produced several hundred (and often over 1,000) barrels of oil per day ("BOPD"). Ex. SO-26 at 1-41 (daily production records ending October 31, 2024).¹ Beginning in 2014, the Well began to experience a 6% decline trend. Test. of Belanger.

11. During its 17+ years of operation, the Well has experienced several shut-ins during which production ceased. Ex. SO-10, 26. The shut-ins varied in length and resulted from different reasons, including hurricanes, repairs, third-party issues such as pipeline access, and mechanical issues. Test. of Belanger. Mr. Belanger opined that short-term shut-ins (i.e., less than 30 days) are typically not a problem, but longer duration shut-ins can be problematic, particularly as a well ages because, as pressure declines through production, it becomes more difficult to push the fluids from the reservoir up the 12,000 feet to the surface. *Id.*

¹ Exhibit SO-10 is largely duplicative of Exhibit SO-26. Both exhibits are the daily production records, but Ex. 10 runs through March 31, 2024, whereas Ex. 26 runs through October 31, 2024.

12. The Well's two longest shut-ins were from April 25, 2020 through August 6, 2020 (104 days for economic reasons related to the COVID-19 pandemic) and December 2, 2021 through March 20, 2022 (108 days due to the allision at issue). SO-26 at 78-79, 87-89.

13. Generally, when a well is shut-in, due to pressure rebuilding and saturation, it experiences "flush production" when the well is placed back in operation, which is an initial production at a higher rate than the well had produced before the shut-in. Flush production is not sustainable and tends to level off, with production returning to the historical decline trend. See, e.g., SO-26 at 79, 86-87; *see also* Test. of Belanger; Test. of Olson.

14. For the November 2021 month immediately preceding the allision, the Well produced an approximate average of 125 barrels of oil per day ("BOPD"). Ex. SO-26 at 86-87. When repairs were complete and the Well returned to production on March 20, 2022, it experienced "flush" production, with rates higher than the pre-allision production. For the thirty-day period after returning to production (March 20 – April 18, 2022), the Well produced an approximate average of 237 BOPD. SO-26 at 89. The Well continued to produce over 170 BOPD for approximately another two months before dropping to the 100-130 BOPD range beginning in July 2022. *Id.* at 89-91.

15. Mr. Belanger had initially prepared an expert report on damages in June 2022. At that time, the Well was still experiencing "flush production" as expected, and Mr. Belanger assumed that the Well would return to its pre-incident long-term production decline trend. Based on that assumption, he estimated that the shut-in resulted in the inability to recover gross production of 2,626 barrels of oil and 30,215 mcf of gas (net production of 1,982 barrels of oil and 22,813 mcf of gas) through the estimated life of the Well ending in 2044, equaling a present value economic loss of \$227,468. Test. of Belanger; Exs. SO-16, 17, 18.

16. Due to the parties' requested continuance after adding a new party and subsequent consent to trial before the undersigned, new trial dates were selected. During that time, Southern Oil

continued to generate actual production data. Southern Oil's president Mr. Kelley contacted Mr. Belanger to re-assess Southern Oil's damages because he found that production did not return to pre-allision rates. Test. of Kelley. Rather, the 6% decline trend resumed from a lower set point level post-allision. See Test. of Belanger; Ex. SO-26.

17. Mr. Belanger testified that, after the 104-day COVID shut-in, the well experienced increased "flush" production and then returned to its pre-event oil forecasts within about four months. Test. of Belanger. He expected production after the 108-day shut-in to likewise return to the pre-allision rates by October 2022, but after the 108-day allision shut-in and while the Well resumed its 6% decline rate, it did so from a lower set point. Test. of Belanger. He provided an example, comparing a 6% decline rate for a well producing 120 BOPD versus the 6% decline rate for a well producing 95 BOPD; while both decline at 6%, the production from the 95 BOPD rate is lower than the production from the 120 BOPD comparator. *Id.*

18. On May 31, 2024, Mr. Belanger produced an updated expert report. ECF No. 127. Mr. Belanger confirmed that the Well initially produced at a higher than expected rate through July 19, 2022. Test. of Belanger; Ex. SO-19, 20. He opined that, by the end of 2022, however, the Well had established a new production trend from a lower point than its pre-allision trend. Test. of Belanger; Ex. SO-19, 20. Based on his review of the data, Mr. Belanger plotted the Arps curve (i.e., the decline trend analysis first documented by J.J. Aarps in 1945), and concluded that post-allision production was 9.24% lower than the pre-allision production. Test. of Belanger; Ex. SO-20.

19. The Well experienced another shut-in in September 2022 (for 13 days), which likewise initially resulted in higher production rates through November 3, 2022. SO-26 at 91-93. Mr. Belanger did not address that shut-in or the reasons that precipitated that particular shut-in, which was closer in time to the year-end production decline forming the basis of Mr. Belanger's damages calculation.

20. Mr. Belanger sought to determine the cause of the lower production trend. He conducted a material balance analysis, which provides information to determine how a reservoir is behaving and estimates the reserves in place as well as how much gas and how much liquid is in the reservoir at any given time due to changes in pressure that changes as production progresses. Test. of Belanger. Mr. Belanger did not conduct any new tests or studies for this material balance analysis. *Id.* Rather, he relied on the daily production reports and the March 2007 Core Labs' Volatile Oil Reservoir Fluid Study, particularly the Constant Volume Depletion data on page 14, to construct the material balance analysis of the reservoir and get an idea of how the Well's reservoir fluid will behave. *Id.*; *see also* SO-25 at 14. He also used the two pressure transient analysis reports, dated 2008 and 2010, which provided pressure information for use in the material balance analysis as well as information to calculate "skin" and permeability. Test. of Belanger; *see also* SO-27, 28.

21. Mr. Belanger characterizes the Well as involving a combination drive reservoir, with one of the drive mechanisms being the expansion of the gas cap and the gas flowing into the well bore to help assist and lift the oil that enters the well bore to the surface. Test. of Belanger.

22. He attributes the 2022 year-end lower production rate to the shut-in because nothing in the well bore explained why the Well did not return to its pre-shut-in levels. Mr. Belanger opined that the gas-to-oil ratio ("GOR") was lower post-allision than it was pre-allision. He states that the GOR decreased while the Flowing Tubing Pressure ("FTP") increased, which he found perplexing because he would expect the FTP to decrease if the GOR decreased. *Id.*

23. Mr. Belanger concluded that the change in production rate was due to the relaxation of the gas cone and the gas cap's inability to restore the cone to its prior size, which resulted in inadequate gas quantities to the reservoir to lift the oil, thereby reducing oil production. He opined that, when the Well came back on production after the allision, the gas flow rate was not adequate to assist the lift of oil to the surface at the same rate as it had been doing pre-allision. *Id.*; Ex. SO-29.

24. Mr. Belanger recognized that there are numerous potential reasons for the lower production and he sought to rule out other possible causes. He ruled out choke changes, salt/scale/paraffin, water production changes and changes to the GOR. Test. of Belanger. After ruling out those causes, he concluded that the lengthy 108-day shut-in altered the physical characteristics of the reservoir by allowing the gas cone to relax, which thereby reduced gas flow in adequate quantities to lift the oil resulting in a production trend from a set point that was lower than the pre-allision production set point. *Id.*; Ex. SO-29; *see also* Exs. SO-19, 20. He opined that this result did not occur after the 104-day shut-in in 2020 because, at that time, the Well's pressure was higher than it was 18 months later when the M/V MR. CADE allided with the Well, allowing for the gas cone to re-establish. Test. of Belanger. *Compare* Ex. SO-26 at 77-79 (FTPs in the 900-1,000 range as reflected in fifth column under Test Results on left of daily production), *with id.* at 86-89 (reflecting FTPs in the range of 600).

25. Mr. Belanger testified that, in his updated opinion, the shut-in caused the Well to sustain a lower production rate that will result in a reduction of the ultimate oil and gas produced from the reservoir versus what it would have produced absent the allision because the Well will now reach the end of its economic life in 2041 rather than 2044. Test of Belanger. On an undiscounted basis, Mr. Belanger asserts that this 9.24% lower production trend will result in the Well's inability to economically produce 52,596 BBL of oil and 845,593 MCF of gas resulting in a net loss to Southern Oil of 39,710 BBL of oil and 638,423 MCF. This equates to a gross economic loss of \$4,346,175, which using a 10% discount rate, constitutes a net present value economic loss of \$2,428,804. Test. of Belanger; *see also* Ex. SO-23.

26. In contrast to Mr. Belanger, Mr. Olson opined that there was no anomalous decline in oil production in December 2022, and he disagreed with Mr. Belanger's Aarps curve plots and Well expectations, his projections of GOR and gas production, and the foundation of his economic analysis.

Mr. Olson testified that his review of the data does not reflect the 9.24% lower production set point beginning in December 2022, asserting that Mr. Belanger's subjective analysis of the historical data reflects such a small difference that many reservoir engineers would not find any change at all. He further testified that, when production numbers exceed forecasted production for several months as occurred in March through July 2022, those barrels have to come out of the estimated future production curve. He believes that the current production is predictable by looking at the reservoir's behavior over the 2020-2022 period. Test. of Olson.

27. Mr. Olson described the Aarps curve as a straight line projection of historical production with different engineers often reaching very different opinions based on their interpretations of the historical data. Mr. Olson criticized Mr. Belanger's Aarps curve for charting his forecast projection based on the peaks of the historical data, rather than from the mid-points of the peaks and valleys, and for assuming a constant 1600 GOR, which dishonors the decline that started back in 2020 and continues to date and ignores the fact that gas is declining faster than his prediction. *Id. see Ex. A-2.*

28. Mr. Olson also disagreed with Mr. Belanger's assertion that the shut-in caused relaxation of the gas cone which inhibited production, finding that theory disproven by the high production rate experienced by the Well for six months after resuming operations. He testified that, had the Well been short of gas by relaxation of the gas cone, the rates would have been the same but the Well was strong on oil and weak on gas. Mr. Olson opined that gas saturation of the Well was constantly changing and criticized Mr. Belanger's focus on GOR rather than GLR (gas liquid ratio) which he testified is more relevant to determine lift in the reservoir and measured over 500, which is more than adequate for the needed lift. Test. of Olson.

29. Mr. Olson further criticized Mr. Belanger for not using any accepted method of classifying reserves, such as provable (P-90), probable (P-50) or possible (P10), employed by the

Society of Petroleum Engineers, the Association of American Petroleum Geologists or the Securities and Exchange Commission (“SEC”). *Id.*

30. Mr. Olson testified that he determined that the reservoir should be characterized as a super-critical fluid reservoir, based on the data in the Core Labs study (SO-25), rather than either a gas condensate or oil reservoir. Super-critical fluid has characteristics of both a liquid and gas and is defined by pressure volume temperature characteristics. Mr. Olson, however, has no experience with super critical fluid reservoirs and is not aware of any other super critical reservoir in this area of the Gulf of Mexico. *Id.*

31. Mr. Olson also reviewed data generated by independent, third party reservoir estimator, Netherland Sewell, which he testified reflects that Southern Oil did not make any change to its reservoir estimates in its public SEC filings suggesting the inability to economically produce the Well, as suggested by Mr. Belanger. Mr. Olson also testified that Netherland Sewell’s reservoir estimate does not reflect a 2041 end of life for the Well. *Id.*

32. Mr. Olson posits that the phase changes of the reservoir impact the ultimate performance of the Well because, as you liberate gas and the gas sometimes liberates oil, the bubbles clog the pores of the reservoir and eventually reach saturation where you cannot move in the reservoir which reduces the productivity of the well. He also opines that the skin value has increased over time from production and has rendered a fraction of the reservoir impermissible to flow around the well bore which results in lower production. *See* Ex. SO-27 at 3 (“The reduction in transmissibility is probably not a function of a no-flow condition but indicative of a phase change from gas to oil.”). So the 2010 Pressure Transient Analysis Report (Ex. SO-28) indicates that the Well is going to produce less and less over time because of phase changes. Test. of Olson.

33. Southern Oil called its president, Harvey Kelley, in rebuttal. Mr. Kelley testified that he has worked on the Well since 2006, and it is not a super-critical reservoir, which he has never seen in Louisiana. Test. of Kelley.

34. Mr. Kelley also testified that, contrary to Mr. Olson's opinion, independent third-party analyst Netherland Sewell did reduce its reserve estimates for this Well. *Id.*

35. Mr. Kelly stated that the skin continues to get worse, which is a factor in the ability for fluid to flow into perforations into the well bore, explaining that gas bubbles are immobile and with the years of production, there is not as much pressure as there used to be. *Id.*

36. No party provided any evidence as to whether the useful life of the Corvus Platform has been extended by the repairs made as a result of the allision.

37. Mr. Belanger did not calculate how much longer the Well would need to remain in operation to produce the same volume of oil and gas as it would have produced had the 108-day delay not occurred. He did, however, provide the initial opinion as to the value of the delayed production, opining that the net present value of the delayed production caused economic damages of \$227,468. His updated opinion indicated that, not only did Southern Oil sustain damages from the 108 days of delayed production but also that physical changes to the reservoir itself resulted from the shut-in and resulted in a lower production rate. Assuming the same 6% decline trend and forecasted prices from that lower production rate, the Well would reach its economic life in 2041 rather than the previously anticipated 2044, resulting in net present value of Southern Oil's economic damages of \$2,428,804.

38. The parties provided conflicting testimony, however, regarding whether Southern Oil recognized this 3-year reduced life expectancy of the Well (from 2044 to 2041) in its reservoir estimates contained in its SEC public filings, which of course is information designed for the public's use in investment decisions. Neither party introduced the underlying evidence that these conflicting opinions are based on to determine whether Southern Oil had recognized the reserve estimate losses

being sought in this litigation for ordinary business purposes (such as its SEC filings) or whether the estimated losses opined by Mr. Belanger were solely forecasted for purposes of this litigation.

B. Alliance's Loss of Use Damages

39. Ryan Landry is currently the Vice President of SeaTran Marine. He joined SeaTran in 2014 and previously served as Director of Finance and then CFO before becoming Vice President. Landry Depo. (ECF 198-1) at 6:14-7:1. In December 2021, he managed the accounting and finance operations and logistical support and ground operations, as well as sales, and he oversaw other operations. *Id.* at 8:6-14.

40. SeaTran contracts with vessel owners to provide management, charter, support and oversight services for vessels, and subcontracted some of those services to Alliance/Helix. *Id.* at 39:14-21.

41. SeaTran had thirteen aluminum hull crew boats vessels in December 2021, but five of them were "laid up," three were working abroad, and five were working in the Gulf of Mexico. *Id.* at 8:15-23; 9:17-10:6; 16:7-10; 17:15-25.

42. The M/V MR. BLAKE, the M/V MR. EVAN and the M/V MR. RIDGE were not suitable replacement vessels for the M/V MR. CADE because the M/V MR. CADE's capabilities superseded those vessels. The M/V MR. J.O. was a larger vessel with higher capabilities, so it was a suitable replacement. *Id.* at 19:7-16; 20:15-22.

43. The M/V MR. J.O. was on spot charter during December 2021, but its use was strong, approximately 80%. *Id.* at 20:23-22:17. After the M/V MR. CADE was damaged, the project continued with the use of the M/V MR. J.O. as the replacement vessel. *Id.* at 26:12-23.

44. Alliance and Helix, not SeaTran, managed the charter support for the M/V MR. CADE, and putting the M/V MR. J.O. on the project in place of the M/V MR. CADE took it off the spot market. *Id.* at 32:5-22; 33:4-15; 35:12-36:19.

45. All five vessels were actively working under the management agreement with Alliance at the relevant time. *Id.* at 40:25-41:20.

46. The M/V MR. J.O.'s charter hire was \$6,500 per day, and the M/V MR. CADE's charter hire was \$5,000 per day. *Id.* at 42:11-17.

47. The M/V MR. CADE underwent repairs for 67 days, and crew stayed with the vessel during repairs. *Id.* at 42:18-22; 45:12-15; *see also* Ex. J-87 at 30-31 (reflecting no log entries for M/V MR. CADE during repair period of December 3, 2021 – February 6, 2022).

48. Although the M/V MR. CADE's estimated vessel off hire date was December 5, 2021, the vessel logs reflect that the charter continued after December 5, 2021. Landry Depo. at 44:2-45:11; *see also* Exs. J-83, 86, 87.

49. SeaTran experienced a gross revenue loss of \$335,000 due to the loss of use of the M/V MR. CADE during the 67-day repair period, or a gross revenue loss of \$348,400 based on the inability to use the MR. J.O. at its ordinary \$6,500 daily rate assuming an 80% utilization rate. Landry Depo. at 49:1-50:10; 22:11-17; 23:3-14.

50. No evidence was introduced, however, to establish the operational expenses associated with generating the lost revenue described above. *Id.* at 52:5-53:5; 29:5-9; 30:24-31:22.

II. CONCLUSIONS OF LAW

1. This Court has jurisdiction over the claims in the complaint under the admiralty and maritime laws of the United States, 28 U.S.C. § 1333, and Rule 9(h) of the Federal Rules of Civil Procedure. Venue is proper in the Eastern District of Louisiana under 28 U.S.C. § 1391(b) because a significant portion of the events occurred within this district. All parties consented to proceed before a United States Magistrate Judge pursuant to 28 U.S.C. § 636(c).

2. Damages for lost profits are allowed under general maritime law, and the mere fact that such damages may not be susceptible of exact measurement does not make them any less

recoverable. *In re ENSCO Offshore Co.*, 990 F. Supp. 2d 751, 757 (S.D. Tex. 2014) (quoting *Domar Ocean Transp., Ltd. v. Indep. Refin. Co.*, 783 F.2d 1185, 1191 (5th Cir. 1986); *Rogers Terminal & Shipping Corp. v. Int'l Grain Transfer, Inc.*, 672 F.2d 464, 466 (5th Cir. 1982)).

3. District courts have discretion to adopt any reasonable measure of damages that compensates the injured party in an effort “to place the injured person as nearly as possible in the condition he would have occupied if the wrong had not occurred.” *Id.* at 761 (quoting *Freeport Sulphur Co. v. S/S Hermosa*, 526 F.2d 300, 304 (5th Cir. 1976)). The profits “must have actually been, or may be reasonably supposed to have been, lost, and the amount of such profits . . . proven with reasonable certainty.” *Id.* (quoting *The Conqueror*, 166 U.S. 110, 125 (1897)). Indeed, “[i]t is a basic concept of damages that they must be proved by the party seeking them.” *Servicios-Expoarma, C.A. v. Indus. Mar. Carriers, Inc.*, 135 F.3d 984, 995 (5th Cir. 1998) (citing *Prunty v. Ark. Freightways, Inc.*, 16 F.3d 649, 652 (5th Cir. 1994); *Pizani v. M/V Cotton Blossom*, 669 F.2d 1084, 1088 (5th Cir.1982)).

4. Deferred production damages generally represents the difference between the value of gas and condensate that would have produced during the period a well is shut-in and the present value of that same product when it is actually produced over the remaining life of the well. *Nerco Oil & Gas, Inc. v. Otto Candies, Inc.*, 74 F.3d 667, 669–70 (5th Cir. 1996); *Agip Petroleum Co. v. Gulf Island Fabrication, Inc.*, 17 F. Supp. 2d 660, 661 (S.D.Tex.1998) (“The practical and economic measure of an oil company's loss from delayed production is the difference between the net revenue flow with and without the delay.”).

5. The Fifth Circuit began defining the types of damages a plaintiff may recover for lost or delayed production of offshore oil and gas reserves in *Continental Oil Co. v. SS ELECTRA*, 431 F.2d 391 (5th Cir. 1970). Since then, the court has recognized that “no single measure of damages

[is] definitive when a production facility or vessel is shut in for repairs because of damage caused by a negligent third party.” *ENSCO Offshore*, 990 F. Supp. 2d at 761 (citing *Nerco*, 74 F.3d at 669).

6. In *Continental Oil*, the SS ELECTRA allided with an offshore platform, which damage halted production from two producing wells for 130 days. 431 F.2d at 391. Faced with the choice of either awarding net profits or interest on net profits as damages for a delay in production, the Fifth Circuit chose net profits, stating:

Profit on oil production is simply one means of measuring the damages suffered. The plaintiffs have lost the use of their capital investment in lease, platform and producing wells for 130 days during which that investment was tied up without return. The fact that the same amount of profit can be made at a later date with the same investment of capital by removing from the ground like quantity of oil at the same site does not alter the fact that the plaintiffs are out of pocket a return on 130 days use of their investment.

Id. at 392. The court expressly noted that it “need not consider whether lost profits or a fair return on investment is a better measure” because the only evidence was lost profits. *Id.* at 393 n.3.

7. The Fifth Circuit later acknowledged that awarding net profits for delayed production might result in a double recovery. *In re TT Boat Corp.*, No. 98-0494, 1999 WL 1276837, at *3 (E.D. La. Dec. 21, 1999) (citing *Geo-1966, Inc. v. Shell Oil Co.* 888 F.2d 1390 (5th Cir. 1989) (mem.) (stating that the net profit formula for quantifying lost production might produce an inequitable result and referring to footnote 3 of the *Electra* decision)).

8. In *Nerco Oil & Gas, Inc. v. Otto Candies, Inc.*, 74 F.3d 667 (5th Cir. 1996), a case involving a claim for deferred (not lost) production, the Fifth Circuit held that net profits are not the definitive measure of damages when an offshore drilling platform is temporarily shut down. 74 F.3d at 669-70. Finding *Geo-1966* instructive, the district court had declined to award damages based on net profits (as offered by plaintiffs’ expert) and instead used the “fair return on investment” or “present value” method (as offered by defendant’s expert) of calculating damages. *Lleco Holdings, Inc. v. Otto Candies, Inc.*, 867 F. Supp. 444, 448 (E.D. La. 1994). *Nerco* thus authorizes a no incident/incident calculation as an appropriate measure of deferred production due to shut in of well

after allision. *See also Agip Petroleum*, 17 F. Supp. 2d at 661–62 (holding that “[t]he practical and economic measure of an oil company's loss for delayed production is the difference between the net revenue flow with and without delay.”).

9. Whether the lost profits approach or present value/fair return on investment approach is the appropriate measure of delay damages depends on the facts of the case. *See TT Boat Corp.*, 1999 WL 1276837, at *4 (citing *Mobil Expl. & Producing v. A-Z/Grant Int'l Co.*, No. 91-3124, 1996 WL 204431, at *1 (E.D. La. Apr. 24, 1996) (Fallon, J.)).

10. Damages for the loss of profits or use of a vessel pending repairs is only allowed “when profits have actually been, or may be reasonably supposed to have been, lost, and the amount of such profits is proven with reasonable certainty.” *Inland Oil & Transp. Co. v. Ark-White Towing Co.*, 517 F. Supp. 651, 652 (E.D. La. 1981) (quoting *The Conqueror*, 166 U.S. at 125), *modified*, 696 F.2d 321 (5th Cir. 1983).

A. Southern Oil’s Damages

11. The preponderance of the evidence establishes that the 108-day shut-in period caused Southern Oil to sustain economic losses. The amount of those damages, however, is far less clear.

12. Southern Oil did not produce any evidence of damages based on its cost of capital under *Continental Oil*. Instead, Southern Oil relied solely on Mr. Belanger’s incident/no-incident analysis under *Nerco*.

13. Mr. Belanger’s first *Nerco* analysis concluded that Southern Oil sustained \$227,468 in damages as a result of the 108-day shut-in. Mr. Olson did not refute Mr. Belanger’s initial opinion that the 108-day shut-in resulted in economic losses of \$227,468, other than to suggest that the Well experienced flush production while oil prices were higher than anticipated. Mr. Olson did not make any mathematical calculation to ascertain how the flush production at higher prices impacted Mr. Belanger’s estimate of \$227,468 in economic damages.

14. Instead of addressing Mr. Belanger's initial opinion as to the economic damages sustained by the 108-day shut-in, Mr. Olson focused his criticism on Mr. Belanger's updated opinion, also employing a *Nerco* analysis, suggesting that the shut-in caused physical changes to the reservoir gas cone that resulted in slower production that will lead to the end of the Well's economic life in 2041 rather than 2044, thereby precluding Southern Oil's recovery of additional product during that three year period.

15. While acknowledging that a prudent operator could take steps to improve production rates, Southern Oil did not task Mr. Belanger with determining what, if any, steps could be taken to restore the prior production rate.

16. Mr. Belanger is a reservoir engineer and has provided forecasts for Southern Oil for many years. However, he has no experience or training in forensics and did not cite to any case studies or literature addressing production declines resulting from a relaxation of a gas cone after a lengthy shut-in.

17. Mr. Belanger's original May 2022 opinion was based on one price forecast, but he used a different price forecast when drafting his 2024 opinion. Southern Oil failed to explain the 2041-2044 oil price forecast used to determine that the Well's economic life would end by 2041 rather than 2044 and did not explain why Mr. Belanger estimated continued production through 2044 in his June 2022 opinion but only through 2041 in his updated opinion.

18. Although Mr. Belanger ruled out certain potential causes for the decreased production he saw before opining that the decrease resulted from changes in the physical reservoir resulting from the shut-in, he did not address the impact of the 13-day shut-in in late September 2022 that more closely in time preceded the December 2022 decline nor did he rule out other potential causes of that decline suggested by Mr. Olson (e.g., defective flapper valve, which could partially block flow and

impede production and for which there is no way to test) or the natural phenomenon occurring in the reservoir as a result of ordinary production (e.g., transmissibility issues).

19. Mr. Belanger did not conduct any new tests or studies in an effort to discern the reason for the 9.24% lower production trend he charted nor did he undertake any testing or studies to explain the anomaly of decreasing GOR with increasing FTP, which he conceded was perplexing.

20. The parties offered conflicting testimony regarding whether Southern Oil has in fact recognized a shorter productive life for the Well in its normal course of its business (i.e., public SEC filings).

21. Considering the conflicting testimony, absence of any post-incident testing or studies to support Mr. Belanger's opinion as well as unanswered questions regarding "perplexing" data, Southern Oil has failed to establish, by a preponderance of the evidence, that it has sustained damage to the reservoir itself that will result in cessation of operations in 2041 rather than 2044. At most, Southern Oil has established that the 108-day shut-in was *a* possible cause of the lower production seen by Mr. Belanger, but it has not established, by a preponderance of the evidence, that same resulted from the 108 day shut-in of the Well (from December 2021 – March 2022) rather than from other causes, such as natural changes in the reservoir or operational issues. Accordingly, Southern Oil has not established, by a preponderance of the evidence, that to a reasonable degree of certainty, it will suffer economic losses of \$2.4 million in lost production as a result of the allision and consequent 108-day shut-in.

22. In contrast, Alliance has failed to refute, and Southern Oil has established, by a preponderance of the evidence and to a reasonable degree of certainty, that Southern Oil sustained \$227,468 in damages as a result of the 108-day shut-in as a result of production that was not conducted during that period.

B. Alliance's Damages

23. Although Alliance established the gross revenues potentially earned by the M/V MR. CADE and/or the M/V J.O., Alliance failed to introduce any evidence whatsoever as to the operational expenses associated with generating that gross revenue. As such, Alliance has failed to establish, by a preponderance of the evidence, to a reasonable certainty, the amount of lost profits associated with the loss of use of any vessel during the 67-day repair period.

C. Interest

20. “[I]n maritime cases the award of prejudgment interest is the rule, rather than the exception, and the trial court has discretion to deny prejudgment interest only where peculiar circumstances would make such an award inequitable.” *Corpus Christi Oil & Gas Co. v. Zapata Gulf Marine Corp.*, 71 F.3d 198, 204 (5th Cir. 1995); *accord. Ryan Walsh Stevedoring Co. v. James Marine Servs., Inc.*, 792 F.2d 489, 492 (5th Cir. 1986). The award of prejudgment interest serves not as a penalty but as compensation for the use of funds to which the claimant was rightfully entitled. *Cent. Boat Rentals, Inc. v. Pontchartrain Partners, LLC*, 744 F. Supp. 3d 635, 640 (E.D. La. 2024) (Ashe, J.) (citations and quotations omitted).

21. Prejudgment interest may not, however, be awarded for future damages in admiralty cases. *Manson Gulf, L.L.C. v. LaFleur*, 784 F. App'x 233, 237 (5th Cir. 2019) (citing *Couch v. Cro-Marine Transp., Inc.*, 44 F.3d 319, 328 (5th Cir. 1995)).

22. Admiralty courts have “broad discretion in setting the prejudgment interest rate” and may look to “the judgment creditor's actual cost of borrowing money, to state law, or to other reasonable guideposts indicating a fair level of compensation.” *Offshore Marine Contractors, Inc. v. Palm Energy Offshore, L.L.C.*, 779 F.3d 345, 351 (5th Cir. 2015) (quoting *Gator Marine Serv. Towing, Inc. v. J. Ray McDermott & Co.*, 651 F.2d 1096, 1101 (5th Cir. Unit A July 1981) (internal citations omitted)); *see also In re M/V NICOLE TRAHAN*, 10 F.3d 1190, 1196-97 (5th Cir. 1994)

(affirming award of prejudgment interest at lower federal rate rather than state rate because no party was domiciled, incorporated or had a principal place of business in the forum state); *Cent. Boat Rentals*, 744 F. Supp. 3d at 640–41 (awarding prejudgment interest at the prevailing state law rate) (citations omitted); *Shallow Water Equip. L.L.C. v. Pontchartrain Partners, L.L.C.*, No. 21-949, 2022 WL 3755041, at *13 (E.D. La. Aug. 30, 2022) (Fallon, J.) (awarding prejudgment interest at Louisiana’s statutory rate because the parties sustaining (and causing) damage were domiciled in Louisiana, and the incident giving rise to this action occurred in Louisiana).

23. The court has discretion to deny prejudgment interest in admiralty cases only when there are peculiar circumstances that would make it inequitable for the losing party to be forced to pay prejudgment interest. *Kenai Ironclad Corp. v. CP Marine Servs., LLC*, 84 F.4th 600, 614 (5th Cir. 2023) (quoting *Comar Marine, Corp. v. Raider Marine Logistics, L.L.C.*, 792 F.3d 564, 580 (5th Cir. 2015) (quoting *Noritake Co. v. M/V Hellenic Champion*, 627 F.2d 724, 728–29 (5th Cir. 1980)); and citing *In re Signal Int’l, LLC*, 579 F.3d 478, 500 (5th Cir. 2009) (citing *Corpus Christi Oil & Gas Co.*, 71 F.3d at 204)).

24. The Court does not find that any party’s dispute with an insurer constitutes peculiar circumstances as necessary to depart from this general rule. Accordingly, the parties are entitled to reasonable prejudgment interest on their claims dating back to December 2, 2021, the date of the allision, to the date of the entry of judgment. The interest shall be calculated using Louisiana’s prejudgment interest rate. Post-judgment interest shall accrue from the date of the judgment in accordance with 28 U.S.C. § 1961(a).

III. CONCLUSION

Based on the foregoing findings of fact and conclusions of law, the Court concludes that Southern Oil sustained damages in the amount of \$1,134,109.39 to repair physical damages to the well and \$227,468 in economic damages relating to deferred production during the 108-day shut-in

period. The Court further concludes that Alliance sustained damages in the amount of \$462,242.52 to repair physical damages to the M/V Mr. Cade. Neither Southern Oil nor Alliance established, by a preponderance of the evidence and to a reasonable degree of certainty, the amount of damages attributable to lost production/reservoir damage or loss of use, respectively.

New Orleans, Louisiana, this 26th day of March, 2025.


DONNA PHILLIPS CURRAULT
UNITED STATES MAGISTRATE JUDGE