IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF DELAWARE

In re: EXTRACTION OIL & GAS, INC., *et al.*, Debtors.	Bankruptcy Case No. 20-11548 (CSS) (Jointly Administered)
PLATTE RIVER MIDSTREAM, LLC, DJ SOUTH GATHERING, LLC, AND PLATTE RIVER HOLDINGS, LLC, Appellants, v. EXTRACTION OIL & GAS, INC., Appellee.	Civil Action No. 20-1532 (CFC)

***EMERGENCY* MOTION TO STAY PENDING APPEAL**

Pursuant to Federal Rules of Bankruptcy Procedure (the "Bankruptcy Rules") 8007 and 8013, Appellants Platte River Midstream, LLC ("PRM"), DJ South Gathering, LLC ("DJS"), and Platte River Holdings, LLC ("PRH"), respectfully request the Court stay the *Order* [D.I. 1038] (the "Order") entered by the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") granting the motion by Appellee Extraction Oil & Gas, Inc. ("Extraction") to reject the parties' contracts under 11 U.S.C. § 365.[1]

[1] Appellants intend to move to consolidate this action with Civil Action No. 20-1457. In the event consolidation is granted, Appellants request the Court's stay also apply to the *Order* [A. D.I. 55] and *Judgment* [A. D.I. 56] that are the subjects of that appeal.

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CORPORATE OWNERSHIP STATEMENT

Platte River Midstream, LLC and DJ South Gathering, LLC are wholly owned subsidiaries of Platte River Holdings, LLC. Platte River Holdings, LLC is majority owned by ARB Midstream, LLC, which is privately held. No publicly held corporation owns 10% or more of Platte River Midstream, LLC's, DJ South Gathering, LLC's stock. Elevation Midstream, LLC purports to own a 25% membership interest in Platte River Holdings, LLC, which ARB disputes.

CERTIFICATE OF COUNSEL

Pursuant to Bankruptcy Rule 8007(b)(4) and District Court Rule 7.1, undersigned counsel hereby certifies that he conferred with counsel for Extraction concerning the relief requested in this Motion. Extraction advised that it opposes a stay of the Order pending appeal.

Further certifications of counsel required by the Bankruptcy Rules and the District Court Rules are set forth in the Declaration of Matthew B. Harvey in Support of Emergency Motion to Stay Pending Appeal, attached as Exhibit M.

REQUEST FOR ORAL ARGUMENT

Appellants request oral argument on this Motion.

CERTIFICATE OF COMPLIANCE WITH LENGTH LIMITS

Pursuant to Bankruptcy Rules 8007(f)(3)(A) and 8015(h), this Motion does not exceed 5,200 words, excluding the coverage page, the corporate ownership statement, the certificate of counsel, the request for oral argument, this certificate of compliance, and the signature block.

INTRODUCTION

All of the elements supporting a stay pending appeal are present here. Appellants will suffer imminent irreparable harm absent a stay. Extraction accounts for over 75 percent of Appellants' revenues. Without these revenues, Appellants will be forced to file bankruptcy, cease operating, or both. This is irreparable harm for which there is no effective redress.

Extraction, conversely, will suffer little to no harm if a stay is granted. Appellants transport approximately 95% of Extraction's crude oil production to market. If the Order is not stayed, Extraction will be in breach of Appellants' contracts, and Appellants could cease transporting Extraction's crude oil. This will result in Extraction losing over $85 million in the next six months while the appeal is pending. Far from harming Extraction, a stay maintaining the status quo will prevent Extraction from foregoing significant revenue.

Appellants are likely to succeed on the merits because the Bankruptcy Court made several erroneous legal rulings requiring reversal. *First*, the court incorrectly held that, as a matter of Colorado law, the contracts do not create covenants running with the land. *Second*, contrary to the great weight of authority, the court mistakenly concluded that, even if the contracts create real property covenants, they nevertheless can be rejected under the Bankruptcy Code. *Third*, the court's ruling runs contrary to recent Supreme Court precedent on the effects of contract rejection. This legal error—reviewed *de novo* on appeal—undergirds the Bankruptcy Court's ruling that Appellants' contracts could be rejected. When this error is corrected, Extraction's asserted basis for rejection collapses. *Fourth*, the court applied an overly lenient standard for rejecting executory contracts and misconstrued the relevant facts even under that standard. In particular, the court disregarded unrebutted testimony undermining Extraction's claims that it could avoid the

possibility of halting production, or could withstand the disastrous economic effect of halting production.

Finally, maintaining the status quo is in the public interest. Extraction's only readily available transportation alternative is trucking. Unrebutted testimony below showed this would place over 1,000 oil tanker trucks on the roads of urban communities. Trucking is the most dangerous form of transporting crude oil, and its risks are amplified here, because these trucks would be transiting Colorado roads in winter, when conditions are at their worst. Granting a stay will prevent this harm to the public interest.

RELEVANT BACKGROUND

Extraction is an oil and gas company that operates in urban communities near Denver, Colorado. Appellants own and operate crude oil pipelines that transport approximately 95% of Extraction's oil production under two transportation service agreements (the "TSAs"). Extraction is Appellants' largest customer, accounting for [redacted]% of PRM's revenue and [redacted]% of DJS's revenue. *See* Declaration of Rogan McGillis, attached as Exhibit A, ¶ 10 Indeed, Appellants' pipelines were custom built to service Extraction's needs. *Id.* ¶ 13. The pipelines cost hundreds of millions of dollars to build. *Id.* ¶¶ 6, 9. Appellants recoup this investment over the 10-year terms of the TSAs in the form of tariffs paid by Extraction for Appellants' transportation services. *Id.* ¶ 10.

Under the TSAs, [redacted]. *See* PRM TSA, attached as Exhibit B, at § 2.1; DJS TSA, attached as Exhibit C, at §§ 2.1, 2.4. These dedications are essential to recouping Appellants' investment. The pipelines would not have been built absent the dedications.

Extraction filed for bankruptcy in June 2020. In August 2020, it moved to reject the TSAs. Following trial, the Bankruptcy Court issued a Bench Ruling and the Order permitting Extraction to reject the TSAs. Appellants timely commenced this appeal and now move to stay the Order pending appeal.[2]

STANDARD

When considering whether to stay a bankruptcy court's order, the Court considers four factors:

> (1) whether the stay applicant has made a strong showing that [it] is likely to succeed on the merits; (2) whether the applicant will be irreparably injured absent a stay; (3) whether issuance of the stay will substantially injure the other parties interested in the proceeding; and (4) where the public interest lies.

In re Revel AC, Inc., 802 F.3d 558, 568 (3d Cir. 2015). The Court balances these factors rather than assessing each in isolation. *In re Freedom Commc'ns Holdings, Inc.*, 2009 WL 4506553, at *1 (D. Del. Dec. 4, 2009). Consequently, "failure to satisfy any one of the four factors … might not necessarily be fatal to a motion for stay pending appeal." *In re Calabria*, 407 B.R. 671, 677 (Bankr. W.D. Pa. 2009). Instead, the four factors are considered on a "sliding scale" where a strong showing on one factor may allow for a lesser showing on another. *Revel AC*, 802 F.3d at 568–70. "[D]epending on how strong a case the stay movant has on the merits, a stay is permissible even if the balance of harms and public interest weigh against holding a ruling in abeyance pending appeal." *Id.* at 571. Conversely, "the stronger the balance of harms and public interest is in [movant's] favor, the less a showing of potential success on appeal" is needed. *Id.*

[2] The Bankruptcy Court denied Appellants' request to stay the Order under Rule 8007. *See* Hearing Trans. (Nov. 2, 2020), attached as Exhibit D, at 43:20-44:25.

ARGUMENT

I. Appellants' Imminent Financial Ruin Constitutes Irreparable Harm.

Harm is irreparable if it "cannot be prevented or fully rectified by a successful appeal." *Revel AC*, 802 F.3d at 568 (citation and internal quotations omitted). The prospect of financial ruin constitutes irreparable harm. *See Minard Run Oil Co. v. U.S. Forest Serv.*, 670 F.3d 236, 255 (3d Cir. 2011) ("[A]n exception [to the economic injury rule] exists where the potential economic loss is so great as to threaten the existence of the movant's business.") (citations and internal quotations omitted); *see also, e.g.*, *Ryko Mfg. Co. v. Eden Services*, 759 F.2d 671, 673 (8th Cir. 1985) (affirming injunctive relief where plaintiff would be "possibly forced out of business" otherwise); *Performance Unlimited, Inc. v. Questar Publishers, Inc.*, 52 F.3d 1373, 1382 (6th Cir. 1995) (same); *Stenberg v. Cheker Oil Co.*, 573 F.2d 921, 924 (6th Cir. 1978) (preliminary injunction warranted to avoid "severe financial hardship"); *Newlife Homecare Inc. v. Express Scripts, Inc.*, 2007 WL 1314861, at *5 (M.D. Penn. May 4, 2007) (evidence plaintiff would be forced out of business or into bankruptcy constituted irreparable harm); *Beilowitz v. Gen. Motors Corp.*, 233 F. Supp. 2d 631, 644-45 (D.N.J. 2002) (40% revenue loss constituted irreparable harm); *Carlo C. Gelardi Corp. v. Miller Brewing Co.*, 421 F. Supp. 233, 236 (D.N.J. 1976) ("threatened loss of the enterprise" constituted irreparable harm).

If the Order is not stayed, Appellants face insolvency, the loss of their business, or both. *See* Exhibit A ¶¶ 12-15. In addition to losing [redacted] percent of PRM's revenue and [redacted] percent of DJS's revenue if Extraction stops shipping on Appellants' pipeline systems, since the Order was entered, Appellants' lender has called a default under their loan facility and is in the process of accelerating the obligations thereunder, which will force Appellants to file for bankruptcy, cease operating, or both. *See id.* ¶¶ 13-15. This is irreparable harm. *See Minard Run Oil*, 670 F.3d at

255 (affirming finding of irreparable harm based on evidence plaintiff would go out of business or bankrupt absent injunction); *Newlife Homecare*, 2007 WL 1314861, at *5 (same).

II. Extraction Will Not Be Harmed by a Stay.

Extraction will not be unduly harmed by a stay, which simply preserves the status quo. *See In re Zohar III, Corp.*, 2019 U.S. Dist. LEXIS 218031, at *25 (D. Del. Dec. 19, 2019) ("The fundamental purpose of a stay pending appeal is the preservation of the status quo.") (citation omitted). Extraction acknowledges an alternative pipeline system will not be in place for months, and it intended to temporarily use Appellants' pipelines even after rejection. *See* Hearing Trans. (Oct. 7, 2020), attached as Exhibit E, at 76:1-2 (admitting "for the most part, alternative pipeline would not be immediately available to [Extraction]"); *id.* at 87:11-88:13, 102:8-18 (noting an alternative pipeline system would not be available for three-to-six months); *id.* at 193:21-194:2 (stating Extraction intended to use Appellants' pipelines as a walk-up shipper).

Moreover, any short-term savings to Extraction resulting from rejecting its contracts are relatively meager compared to the size of its enterprise. Extraction believes it can garner only $25–$32 million in transportation savings and related value in 2021 by rejecting the PRM TSA, and $4.5–$5.5 million in transportation savings and related value in 2021 by rejecting the DJS TSA. *See* Extraction Rejection Hearing Demonstratives, attached as Exhibit F, at 3, 5. Of course, less will be realized over shorter periods, and any benefits are dwarfed by the revenues Extraction will lose if forced to halt production after rejection if Appellants refuse to transport Extraction's oil. *See, e.g.*, Exhibit E at 199:15-204:5 (admitting absent use of the DJS transportation system, Extraction would have to shut-in production for a period of time and lose approximately $39.2 million in revenue). Foregoing the minimal savings in transportation costs to a billion-dollar oil company does not rise to the level of irreparable harm. *See In re ANC Rental Corp.*, 2002 U.S.

Dist. LEXIS 9409, at *5-6 (D. Del. May 22, 2002) (the quantifiability of savings "weighs against a finding of irreparable harm") (citation omitted). Staying the Order will not harm Extraction.

III. The Companies Are Likely to Succeed on the Merits of Their Appeal.

Likelihood of success on the merits means "a reasonable chance, or probability, of winning." *Revel AC*, 802 F.3d at 568 (citation and internal quotations omitted). It does not require success be "more likely than not." *Id.* at 569 (citation and internal quotations omitted). Given the Bankruptcy Court's legal and factual errors, Appellants have a reasonable chance of success on the merits.

A. The Court Likely Will Reverse the Bankruptcy Court's Legal Errors.

Appellants have a reasonable chance of success because the Court is likely to reverse the Bankruptcy Court's legal errors upon *de novo* appellate review. *See United States v. Higdon*, 493 F. App'x 261, 263 (3d Cir. 2012) (an appellate court's review is "plenary … when such rulings are based on an interpretation of law") (citation omitted). The Bankruptcy Court misinterpreted the governing law in at least four respects:

First, the Bankruptcy Court fundamentally misread Colorado law on covenants running with the land. Under Colorado law, only two requirements are necessary to create covenants running with the land: (1) the parties must intend to create the covenant; and (2) the covenant must touch and concern the land. *See Reishus v. Bullmasters, LLC*, 409 P.3d 435, 440 (Colo. App. 2016) (citating *Cloud v. Ass'n of Owners*, 857 P.2d 435, 440 (Colo. App. 1992)). Whether the parties intended to create the covenant is determined from the provisions of the contract "as a whole …, giving effect to all provisions contained therein." *See Lookout Mtn. Paradise Hills Homeowners' Ass'n v. Viewpoint Assocs.*, 867 P.2d 70, 75 (Colo. App. 1993) (citation omitted). No magic words are necessary. *See TBI Expl. v. Belco Energy Corp.*, 2000 WL 960047, at *4 (5th

Cir. June 14, 2000) ("Our survey of Colorado case law has not revealed any precedent … that a covenant running with the land must be expressed in specific or magical terms.").

A covenant touches and concerns the land when it relates to the parties' use and enjoyment of real property, *i.e.*, when the parties' promises create benefits—and burdens—on the use of real property. *See Reishus*, 409 P.3d at 440 (citation omitted). This is a factual inquiry. *See Bigelow v. Nottingham*, 833 P.2d 764, 767 (Colo. App. 1991), *rev'd in part on other grounds*, *Haberl v. Bigelow*, 855 P.2d 1368 (Colo. 1993) ("'touch and concern' requirement is fulfilled when the covenant operates to benefit the physical use of the land"); *Lookout Mtn.*, 867 P.2d at 75 (building restriction created covenant running with the land where benefits and burdens were closely related to property's use and enjoyment); *see also In re Badlands Energy, Inc.*, 608 B.R. 854, 868 (Bankr. D. Colo. 2019) (whether a covenant closely relates to the land must be "viewed in the context of [the agreement's] purpose").

The Bankruptcy Court misapplied these rules. It held the PRM TSA did not create a covenant running with the land because it did not contain language expressly stating the parties' intent to create a covenant. *See Findings of Fact and Conclusions of Law* [A.D.I. 54], attached as Exhibit G, at 22. Such language is not necessary under Colorado law. *See TBI Expl.*, 2000 WL 960047, at *4. It held neither TSA touched and concerned real property, applying the overly restrictive tests under Texas law followed in *In re Sabine Oil & Gas Corp.*, 550 B.R. 59 (Bankr. S.D.N.Y. 2016). *See* Exhibit G at 25-28, 30. Colorado law does not impose these requirements, and generally follows the same principles recognized in cases where bankruptcy courts held similar transportation agreements created covenants running with the land. *See In re Alta Mesa Res., Inc.*, 613 B.R. 90, 105 (Bankr. S.D. Tex. 2019) (holding gas gathering agreements created real covenants under Oklahoma law because the dedication of interests affected the producer's

"*reserves* even as the hydrocarbons remain[ed] undisturbed" in the ground) (emphasis added); *Badlands*, 608 B.R. at 869 (holding gas gathering agreement created a real covenant under Utah law because the dedication of all interests "in all Gas reserves *in and under*" a specific geographic area encompassed unextracted minerals) (emphasis in original). The Bankruptcy Court gave no consideration to these rulings. *See* Exhibit G at 28.

The Bankruptcy Court also ruled Colorado law requires privity of estate to create a covenant running with the land. *See id*. at 21, 35-44. The court relied on three Colorado cases from 1898, 1907, and 1954, none of which hold horizontal privity is necessary. *See id.* at 35-36; *see also Taylor v. Melton*, 274 P.2d 977, 981-82 (Colo. 1954) (referencing "privity of estate" even though the issue was whether the defendant was bound by a restriction that was not in the defendant's deed, and was only in the deed of his predecessor in title); *Farmers' High Line Canal & Reservoir Co. v. N.H. Real Estate Co.*, 92 P. 290, 293 (Colo. 1907) (referencing "privity of estate" even though the issue was whether a written agreement by a canal owner to furnish water created a covenant that bound the current canal owner); *Hottel v. Farmers' Protective Ass'n*, 53 P. 327, 330 (Colo. 1898) (noting that the existence privity of estate "is not denied"). In the 70 years since those cases were decided, no Colorado appellate court has held privity is a required element. *See, e.g.*, *Reishus*, 409 P.3d at 440 (containing no reference to horizontal privity requirement); *DeJean v. Grosz*, 412 P.3d 733, 739 (Colo. App. 2015) (same); *In re Banning Lewis Ranch Co.*, 532 B.R. 335, 345 n.11 (Bankr. D. Colo. 2015) (same); *MidCities Metro. Dist. No. 1. v. U.S. Bank Nat'l Ass'n*, 2013 WL 3200088, at *3 (D. Colo. June 24, 2013) (same); *Lookout Mtn.*, 867 P.2d at 74 (same); *Cloud*, 857 P.2d at 440 (same); *Bigelow*, 833 P.2d at 767-68 (same).

Second, the Bankruptcy Court held that, even if the TSAs created covenants running with the land, they could be rejected as executory contracts under Section 365. *See Bench Ruling* [D.I.

942-1], attached as Exhibit H, at 12-19. This holding was erroneous because "[c]ontracts forming real property covenants are not executory" and therefore, cannot be rejected. *Alta Mesa*, 613 B.R. at 99 (citation omitted); *see also In re Sabine Oil & Gas Corp.*, 567 B.R. 869, 874 (S.D.N.Y. 2017) ("[I]t is not possible for a debtor to reject a covenant that 'runs with the land,' since such a covenant creates a property interest that is not extinguished through bankruptcy."); *Badlands*, 608 B.R. at 875 (same). To support its incorrect legal conclusion, the Bankruptcy Court erroneously relied on *In re Arden & Howe Assocs., Ltd.*, 152 B.R. 971 (Bankr. E.D. Cal. 1993). *See* Exhibit H at 13-15. Yet *Arden & Howe*'s ruling was specifically abrogated by Congress, a fact Appellants repeatedly raised to the court, but which the court failed even to address in its ruling. *See* Bankruptcy Reform Act of 1994, Section-by-Section Analysis, 140 Cong. Rec. H10752-01 (Oct. 4, 1994) (citing *Arden & Howe*'s ruling as an incorrect ruling necessitating a clarifying amendment). Appellants have a reasonable chance of persuading the Court to follow generally accepted authority rather than the unsupported holding reached by the Bankruptcy Court. *See Revel AC*, 802 F.3d at 568.

Third, the Bankruptcy Court failed to properly apply the Supreme Court's holding in *Mission Product Holdings, Inc. v. Tempnology, LLC*, 139 S. Ct. 1652 (2019), which clarified the effect of rejection. *Mission Product* held, "rejection breaches a contract but does not rescind it. And that means all the rights that would ordinarily survive a contract breach, including those conveyed here, remain in place." *Id.* at 1657–58. "Breach" is not a defined bankruptcy term, and "means in the [Bankruptcy] Code what it means in contract law outside of bankruptcy." *Id.* at 1661. When a contract is breached outside of bankruptcy, the non-breaching party has a choice: it can retain its rights under the contract while suing for damages or it can call the whole deal off, terminating the contract. *See id.* at 1662. The breaching party "has no ability, based on its own breach, to terminate the agreement." *Id.* The same result is true in bankruptcy. *Id.* If the debtor

rejects a contract, "the debtor and counterparty do not go back to their pre-contract positions. Instead, the counterparty retains the rights it has received under the agreement. As after a breach, so too after a rejection, those rights survive." *Id*. The Bankruptcy Court failed to apply the Supreme Court's holding in concluding rejection of the TSAs would render the dedications unenforceable. The dedications are a limitation on Extraction's property. Before the dedications, Extraction was free to transport its oil by any means. Once Extraction entered into the TSAs, it limited its ability to transport oil from designated areas to one means: Appellants' pipelines. As *Mission Product* held, rejection of the TSAs does not rescind or revoke the dedications any more than breach outside of bankruptcy does. Rather, upon rejection, Appellants may continue to enforce rights granted to them under the contract, including the dedications.

The Bankruptcy Court also erred by concluding Extraction may select a claim for damages as Appellants' sole remedy upon breach. The non-breaching party is entitled to elect remedies, not the breaching party. *Mission Prod.*, 139 S. Ct. at 1662. The TSAs make clear the non-breaching party [redacted] the agreement or it [redacted] *See* Exhibit B § 11.3(d); Exhibit C § 12.3(d). Additionally, applicable Colorado law does not allow Extraction to select Appellants' remedies. *See, e.g.*, *In re Hruby*, 512 B.R. 262, 267 (Bankr. D. Colo. 2014) (applying Colorado law and finding damages and injunctive relief "are cumulative and not alternative remedies"). Nor can Extraction use the Bankruptcy Code to force Appellants to select damages alone in lieu of injunctive relief. Although the Bankruptcy Code "encourages creditors to select money damages from among alternative remedies, it does not require creditors entitled to an equitable remedy to select a suboptimal remedy of money damages." *Matter of Davis*, 3 F.3d 113, 116 (5th Cir. 1993). Here, the Bankruptcy Court wrongfully focused on the TSAs' Total Financial Commitments,

concluding Appellants had agreed to accept a claim for money damages as their exclusive remedy. *See* Exhibit G at 33-34. Money damages alone clearly are suboptimal as Extraction will pay the Total Financial Commitments at less than 20 cents on the dollar. Moreover, Extraction's option to pay the Total Financial Commitment is effectively an early termination clause, not a forced remedy. A rejecting debtor cannot use an early termination clause to limit the other party's remedy under the contract where the debtor elected to reject the contract rather than perform under the early termination clause. *See In re Lake Dearborn, LLC*, 534 B.R. 747, 756 (Bankr. N.D. Ill. 2015). Given *Mission Product*'s holding, Appellants have a high likelihood of success in reversing this legal error.

Fourth, the Bankruptcy Court applied the wrong legal standard to determine whether Extraction's rejection of the TSAs was a reasonable exercise of business judgment. *Compare* Exhibit H at 4 ("The 'business judgment' test requires a showing that rejection of the executory contract or unexpired lease will benefit the debtor's estate") (citations omitted), *with N.L.R.B. v. Bildisco & Bildisco*, 465 U.S. 513, 526 (1984) (certain types of contracts require a bankruptcy court apply a standard higher than "business judgment" in evaluating a debtor's decision to reject). Because the TSAs are governed by FERC, the court should have applied a more rigorous standard and considered the public interest and the balance of the equities at the time Extraction filed its motion. *See, e.g.*, *In re FirstEnergy Sols. Corp.*, 945 F.3d 431, 454-55 (6th Cir. 2019) ("[W]hen a Chapter 11 debtor moves a bankruptcy court for permission to reject a filed energy contract that is otherwise governed by FERC … the bankruptcy court must consider the public interest and ensure that the equities balance in favor of rejecting the contract …."); *In re Mirant Corp.*, 378 F.3d 511, 524 (5th Cir. 2004) ("Supreme Court precedent supports applying a more rigorous standard" than the business judgment standard when evaluating a request to reject an agreement

regulated by FERC); *In re Calpine Corp.*, 337 B.R. 27, 38-39 (S.D.N.Y. 2006) ("Both the *Mirant* decision and the FERC Order predicate bankruptcy court jurisdiction to reject energy contracts on the belief that the public interest is adequately considered at a rejection hearing, at least in part through FERC's participation.") (citation omitted). Instead, the court erroneously applied a much lower standard and allowed Extraction's rationale for rejection to evolve over the course of the briefing, up to the rejection hearing itself. *See* Exhibit H at 4-12. These standards are subject to *de novo* review and the bankruptcy court's application of the wrong standard should be reversed. *See Higdon*, 493 F. App'x at 263.

B. The Court Likely Will Reverse the Bankruptcy Court's Factual Errors.

The Bankruptcy Court also committed reversible error in its consideration of the relevant facts.

The Bankruptcy Court ignored substantial evidence that the parties intended to create covenants running with the land, and that the TSAs touch and concern the land. *See* Exhibit G at 22-23, 26-33. The court ignored the express language of the TSAs that dedicates and commits all of Extraction's mineral interests, including current and future production, [redacted] the dedicated areas, as well as the parties' purposes in entering into the TSAs. *See PRM and DJS's Response in Opposition to Extraction's Motion for Summary Judgment* [A. D.I. 21], attached as Exhibit I, at 16-22. The court also overlooked evidence that the TSAs benefit Extraction's real property interests by increasing the value of Extraction's mineral estate and burden the interests by restricting Extraction's use of real property. *See id.* at 22-24. At a minimum, these facts create a triable issue on the elements of a covenant running with the land and made summary judgment improper. *See Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 248

(1986) (summary judgment is improper "if the evidence is such that a reasonable jury could return a verdict for the nonmoving party").

The Bankruptcy Court erred further by disregarding the plain factual evidence of privity between the parties. *See* Exhibit G at 35-44. Extraction contemporaneously received equity in Appellants' pipelines in the same geographic areas as the dedications and formerly owned a portion of the pipeline system at issue that it sold to PRM contemporaneously with executing the PRM TSA. *See* Exhibit I at 30. Additionally, Extraction signed right-of-way agreements giving Appellants the right to use, occupy, and access surface area. *See id.* These right-of-way agreements conveyed property rights and interests under Colorado law. *See, e.g.*, *Booker v. Cherokee Water Dist.*, 651 P.2d 452, 453-54 (Colo. App. 1982) (a contractual license becomes a property right when coupled with an interest). Other bankruptcy courts have held these facts satisfy any privity requirement. *See, e.g.*, *Badlands*, 608 B.R. at 874 (simultaneous conveyances of real property in the same geographic area satisfied horizontal privity); *Alta Mesa*, 613 B.R. at 106 (easements conveyed simultaneously with gas gathering agreements satisfied horizontal privity).

The Bankruptcy Court also ignored or dismissed the serious deficiencies in Extraction's rejection analysis. Extraction currently has no way to transport production delivered on the DJS system through another pipeline. *See* Exhibit E at 199:15-22. Another pipeline will not be connected for months. *See id.* at 76:1-2, 87:11-88:13, 102:8-18 (noting it would take three to six months to have an alternative pipeline system available). Meanwhile, if DJS refuses to transport the production, Extraction will be required to halt production from wells connected to the DJS system. *See id*. at 103:9-14. This would cost Extraction $39.2 million in lost oil revenue over the next six months. *See id*. at 203:16-204:5. A shut-in would also cost Extraction approximately $26

million in lost natural gas revenue over the next six months. *See* Hearing Trans. (Oct. 20, 2020), attached as Exhibit J, at 148:16-149:15. Extraction admitted it never quantified the effect of shutting in its wells or whether the loss of revenue justified any savings resulting from rejecting the DJS TSA. *See* Exhibit E at 193:12-194:17.

Extraction's analysis of the PRM TSA was similarly flawed. There is no alternative pipeline connected to all but a few wellpads serviced by the PRM pipeline. *See id*. at 219:8-16, 226:2-228:13. Extraction has no contract in place with an alternative provider, and no alternative pipeline would be connected for months. *See id.* at 220:5-221:1, 228:4-13. Until then, Extraction would be forced to halt production, but it did not quantify the financial effect of shutting in its wells. *See id.* at 193:12-194:17, 212:5-10.

Extraction claims that, for some wells connected to the PRM system, it can transport oil using tanker trucks. *See id*. at 211:6-13. Extraction conceded, however, that it lacks permits for trucking for many of these wells. *See id*. at 224:14-225:6. Extraction acknowledged that it has not yet sought permits and that there are no assurances permits will be granted. *See id*. at 225:7-9. The record demonstrated the financial effect of shutting in production with wells without an immediate trucking alternative would be over $85 million over the next six months. *See* Exhibit J at 149:16-150:18. Extraction never quantified this financial effect when considering whether to reject the PRM TSA. *See* Exhibit E at 193:12-194:17.

The court was untroubled by the repercussions to Extraction of shutting in wells, accepting the dubious testimony of the company's CEO, who claimed without support that wells perform better after they are shut in and cease producing. *See* Exhibit E at 94:7-16. This testimony rested on production from one well, and Appellants' CFO provided unrebutted testimony that the example well relied upon by Extraction saw production drop below pre-shut-in levels shortly after

the well was brought back online. *See id*. at 94:17-96:15. Moreover, evidence showed prior statements made by Extraction in its SEC filings (signed by Extraction's CEO) directly contradicted Extraction's CEO's testimony. *See* Extraction Oil & Gas, Inc., Quarterly Report (Form 10-K), 53 (May 11, 2020), attached as Exhibit K. The court overlooked these contradictions. *See* Exhibit G.

These factual errors are the foundation for the Bankruptcy Court's Order granting rejection of the TSAs. *See id*. When this Court reviews the record, it will conclude the Order must be reversed. For purposes of this Motion, however, Appellants have a reasonable chance of success on the merits.

IV. The Public Interest Supports Staying the Order.

Staying the Order advances the public's interest "in seeing that parties oblige by their contractual obligations and are not allowed to skirt such obligations at another's expense." *Rex Med. L.P. v. Angiotech Pharm. (US), Inc*., 754 F. Supp. 2d 616, 626 (S.D.N.Y. 2010) (citation omitted); *see also Siemens Bldg. Techs., Inc. v. Camacho*, 168 F. Supp. 2d 425, 427 (E.D. Pa. 2001) ("As a general matter, it is in the public interest to enforce valid contractual obligations").

Conversely, if the Order is not stayed, harm and risk to communities where Extraction operates will be increased through the use of tanker trucks. *See* Haag Rep., attached as Exhibit L, ¶ 78. Even if Extraction were to truck half of their production on PRM (approximately 16,250 barrels per day as of June 2020), it would take at least 80 tanker trucks per day, causing increased traffic congestion, increasing overall safety risks to the public. *Id.* ¶ 77; *see also* Exhibit E at 215:24-217:7. Tanker trucks are disruptive to communities, and are the single most dangerous method of transporting crude oil. *See* Exhibit L ¶ 73. Staying the Order prevents public harm pending appeal. *See United States v. Safehouse*, 2020 U.S Dist. LEXIS 110549, at *35-36 (E.D.

Pa. June 24, 2020) (stay pending appeal was in the public interest because absence of stay would cause disruption to the community).

V. No Bond Should Be Imposed.

The Court should not require a bond. The Court has "wide discretion in the matter of requiring security and if there is an absence of proof showing a likelihood of harm, certainly no bond is necessary." *Cont'l Oil Co. v. Frontier Ref. Co.*, 338 F.2d 780, 782 (10th Cir. 1964) (footnote omitted). If "Debtors will not suffer harm in absence of a stay and … the Bankruptcy Court's Order does not require any monetary payment, there is no need for a bond." *In re Los Angeles Dodgers LLC*, 465 B.R. 18, 38 (D. Del. 2011). Here, granting a stay will not harm the Debtors because of the significant delay the Debtors will face as they attempt to pursue their alleged "alternatives" to the Transportation Systems. Moreover, the Order does not require any monetary payment from Appellants—it is Appellants who will suffer significant damages if rejection of the Transportation Agreements can be immediately enforced by the Debtors.

CONCLUSION

For the reasons set forth above, Appellants respectfully request the Court grant this Motion and enter an order staying the effect of the Order pending the resolution of this appeal, in the form attached hereto as Exhibit N.

Dated: November 19, 2020
Wilmington, Delaware

/s/ Curtis S. Miller

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EXHIBIT A

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF DELAWARE

In re: EXTRACTION OIL & GAS, INC., *et al.*, Debtors.	Bankruptcy Case No. 20-11548 (CSS) (Jointly Administered)
PLATTE RIVER MIDSTREAM, LLC, DJ SOUTH GATHERING, LLC, AND PLATTE RIVER HOLDINGS, LLC, Appellants, v. EXTRACTION OIL & GAS, INC., Appellee.	Civil Action No. 20-1532 (CFC)

DECLARATION OF ROGAN MCGILLIS

Pursuant to 28 U.S.C. § 1746, I, Rogan McGillis, declare under penalty of perjury as follows:

1. Since 2014, I have served as the Chief Financial Officer of ARB Midstream, LLC ("ARB"). ARB is a private oil and gas liquids midstream and marketing / logistics solutions company. I am a co-founder of ARB and member of the ARB's Board of Directors. Given my roles at ARB, I have supervisory responsibility over all financial aspects of ARB and its assets.

2. For the past 10 years, I have been involved in negotiating and developing crude oil or other liquid hydrocarbon pipeline transportation projects. I am familiar with the financial and operational terms contained in these contracts, as well as the financial structures of transportation companies like ARB. In particular, I am familiar with the requirements needed to obtain equity

and debt financing for transportation systems, and the general expectations of transportation companies on recovering capital investments and a return on those investments.

3. Based on my expertise and responsibilities at ARB, I have personal knowledge of the financial impact of halting transportation of Extraction Oil & Gas, Inc.'s ("Extraction") crude oil described below.

ARB Midstream

4. ARB builds and operates pipeline systems to transport crude oil and other liquid hydrocarbons produced from wells throughout North America. The pipeline systems owned and operated by ARB require a multi-million-dollar investment to acquire rights of ways, easements, and permits, install the pipelines and related facilities, and operate the pipeline system.

The Transportation Systems

5. On April 14, 2017, Platte River Midstream, LLC ("PRM") and Extraction entered into a First Amended and Restated Transportation Agreement (the "PRM TSA"), pursuant to which PRM agreed to undertake the expense and effort of constructing, installing, and operating an extensive network of pipelines and related facilities (the "PRM Transportation System") in exchange for Extraction's dedication and commitment of all of its interests in crude oil in, under, and attributable to certain locations in Larimer and Weld Counties to the PRM Transportation System (the "PRM Dedication Area"). ARB is the manager of PRM.

6. I have reviewed PRM's financial statements to determine the amount of capital PRM has spent to build and operate the PRM Transportation System pursuant to the PRM TSA. To date, PRM has spent approximately $140.8 million to date to install 95 miles of pipeline and related facilities to transport Extraction's crude oil produced from the PRM Dedication Area.

7. On January 17, 2018, ARB formed a limited liability company, DJ South Gathering, LLC ("DJ South") as a wholly owned subsidiary of PRH to build and operate the new transportation system (the "DJ South Transportation System"). ARB is the manager of DJ South. PRM and DJ South are referred to together as the "Companies."

8. On May 16, 2018, DJ South and Extraction entered into a Transportation Services Agreement (the "DJ South TSA"), pursuant to which DJ South agreed to undertake the expense and effort of constructing, installing, and operating the DJ South Transportation System in exchange for Extraction's dedication and commitment of all of its interests in crude oil in, under, and attributable to certain locations in the City and County of Broomfield, Colorado, and Adams, Arapahoe, Boulder, and Weld Counties, Colorado to the DJ South Transportation System (the "DJ South Dedication Area"). The PRM TSA and the DJ South TSA are referred to together as the "TSAs." The PRM Transportation System and the DJ South Transportation are referred to together as the "Transportation Systems."

9. I have reviewed DJ South's financial statements to determine the amount of capital DJ South has spent to build and operate the DJ South Transportation System pursuant to the DJ South TSA. To date, DJ South has spent approximately $128.5 million to install an additional 56 miles of pipeline, along with related facilities, to transport Extraction's production downstream.

Compensation to Platte River and DJ South

10. Under the TSAs, Extraction is required to pay a monthly tariff approved by the Federal Energy Regulatory Commission ("FERC") for the volumes it delivers into the Transportation Systems. As Extraction is the primary customer of PRM and DJ South, which were formed primarily to provide transportation services to Extraction, the monthly tariffs paid by

Extraction represent the majority of PRM and DJ South's income and the only way to recover PRM and DJ South's multi-million-dollar investments in the Transportation Systems. Specifically, approximately [redacted] percent of PRM's revenues and [redacted] percent of DJ South's revenues come from Extraction.

11. I have reviewed monthly invoices for both PRM and DJ South to determine the average amount of monthly tariff paid by Extraction to PRM and DJ South. Based on my review, Extraction currently pays an average of approximately [redacted] per month in tariffs to transport approximately [redacted] on the PRM Transportation System and an average of approximately [redacted] per month in tariffs to transport approximately [redacted] per month on the DJ South Transportation System.

Irreparable Harm Caused by Halting Transportation of Extraction's Crude Oil

12. In connection with the bankruptcy proceedings, I understand that the bankruptcy court has granted Extraction's motion to reject the TSAs, which allows Extraction to deliver its crude oil to alternative shippers.

13. As stated above, Extraction's monthly payments are the main source of PRM and DJ South's revenue, with Extraction's monthly payments amounting to approximately [redacted] percent of PRM's revenue, and [redacted] percent of DJ South's revenue. Given the nature of the Transportation Systems, which were built to provide services to a specific producer (Extraction), PRM and DJ South cannot realistically replace the volumes of crude oil transported on their systems (and replace the revenue received from Extraction) if Extraction were to stop transporting its production on the Transportation Systems.

14. If Extraction stops delivering its production into the Transportation Systems, and stops paying PRM and DJ South the monthly tariffs, the Companies will not be able to finance their services and other financial obligations. As Extraction's monthly tariffs are vital to the Companies' ongoing operations, absent the revenues from the tariffs, I anticipate PRM and DJ South both would become insolvent and no longer financially viable in under one month. If the companies become insolvent, the pipelines will cease operations.

15. Additionally, Extraction's rejection of the TSAs triggers a default under the Companies' own credit agreements. On November 11, 2020, the Companies' lender placed the Companies in default and could accelerate the debt at any time. If Extraction stops delivering crude oil into the Transportation Systems in the near term, we expect the Companies' lender to call its note, forcing the Companies to file for bankruptcy.

16. Finally, as a result of Extraction's diversion of crude oil away from the PRM Transportation System, 35 individuals, who are employed full time by ARB and/or its affiliated entities are at imminent risk of losing their jobs and becoming unemployed. These employees are engaged in field operations, matters concerning terminals, land, corrosion and integrity analysis, management, administration, finance and accounting, human resources, corporate support, and engineering and project management. These employees are critical to ARB and/or its affiliated entities' operations and, as full-time employees, their financial livelihood is tied to their employment by ARB.

I declare under penalty of perjury under the laws of the United States of America that the foregoing is true and correct.

Executed on November 19, 2020



Rogan McGillis
Chief Financial Officer
ARB Midstream, LLC

EXHIBIT B

Redacted in its Entirety

EXHIBIT C

Redacted in its Entirety

EXHIBIT D

UNITED STATES BANKRUPTCY COURT
DISTRICT OF DELAWARE

IN RE:	Chapter 11
EXTRACTION OIL & GAS, INC., *et al.*,	Case No. 20-11548 (CSS)
Debtors.	Courtroom No. 6 824 North Market Street Wilmington, Delaware 19801
EXTRACTION OIL & GAS, INC., Plaintiff, v. REP PROCESSING, LLC, Defendant.	Adv. Proc. No. 20-50813
EXTRACTION OIL & GAS, LLC, Plaintiff, v. PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC, Defendants.	Adv. Proc. No. 20-50833
EXTRACTION OIL & GAS, INC., Plaintiff. v. ROCKY MOUNTAIN MIDSTREAM, LLC, Defendant.	Adv. Proc. No. 20-50840
	November 2, 2020 9:00 A.M.

BEFORE THE HONORABLE CHRISTOPHER S. SONTCHI
UNITED STATES BANKRUPTCY JUDGE

recess to wet my whistle and then, of course, I will take any questions in connection with the ruling and then we can proceed with the balance of the agenda. So, we will take a short recess.

(Recess taken at 10:00 a.m.)

(Proceedings resumed at 10:05 a.m.)

THE COURT: I also want to thank the parties, in particular, of course, the lawyers and that goes for everybody Grand Mesa, Platte, Elevation, the debtors, for, really what was a remarkably well-presented trial, you know, light speed. So, well done to you as professionals.

I know half of you or more than half of you aren't happy with me right now, but that is part of the job, I suppose.

Does anybody have any questions?

MR. MILLER: Your Honor, Curtis Miller from Morris Nichols on behalf of Platte River and DJ South. I do have one questions, Your Honor.

THE COURT: Yes.

MR. MILLER: I expect to know the response to this based on Your Honor's extensive ruling that you just provided, but under the rules I'm required to ask the Bankruptcy Court first and that is a request for a stay pending appeal. Obviously, there is no order entered. There will be something that will be circulated and that will be

entered soon enough, but I think a request for the stay under the rules can still be requested prior to an order actually being issued.

THE COURT: No. I will deny that and allow you, you know, obviously, to go through your appeal processes. Is this -- well, I don't know if this a final order or not, but you will figure that out.

No. I think the likelihood of success on the merits prong, obviously given the nature of my ruling, weighs heavily in favor of the debtors, at least in connections with stay pending appeal. It's a balancing test where a stronger likelihood of success means you don't have to make quite the showing of irreparable harm and vice versa, but I don't think you can make a likelihood of success argument at all. I think the irreparable harm is covered by money damages, as I said a couple times in the ruling. So, you lack both of those prongs.

A balance of the equities already in the context of my hearing and said that they weigh in favor of the debtors. I have also considered the public interest and say that that weighs in favor of the debtors. So, I will deny the motion for stay pending appeal for failure to meet any of the four criteria and wish you all the best.

MR. MILLER: Thank you, Your Honor.

THE COURT: You're welcome.

EXHIBIT E

UNITED STATES BANKRUPTCY COURT
DISTRICT OF DELAWARE

IN RE:	Chapter 11
EXTRACTION OIL & GAS, INC., *et al.*,	Case No. 20-11548 (CSS)
Debtors.	Courtroom No. 6 824 North Market Street Wilmington, Delaware 19801
EXTRACTION OIL & GAS, INC., Plaintiff, v. GRAND MESA PIPELINE, LLC, Defendant.	Adv. Proc. No. 20-50816
EXTRACTION OIL & GAS, LLC, Plaintiff, v. PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC, Defendants.	Adv. Proc. No. 20-50833
EXTRACTION OIL & GAS, INC., Plaintiff. v. ELEVATION MIDSTREAM, LLC, Defendant.	Adv. Proc. No. 20-50839
	October 7, 2020 10:00 A.M.

BEFORE THE HONORABLE CHRISTOPHER S. SONTCHI
UNITED STATES BANKRUPTCY JUDGE

A Well we recognized that for the most part alternative pipeline would not be immediately available to us and we had to understand exactly what our transaction would look like or what a transition plan would look like so that we could accurately model what the cost and effects would be to the company.

Q Okay. So now let's go ahead and turn to the analysis of specific contracts. We'll start with Platte River and DJ South and actually will address each one separately because they present slightly different issues.

So we're talking about the Platte River transportation service agreement, Debtors' Exhibit 24. Who is Platte River?

A Platte River is a wellhead gathering company that currently transports extractions, oil productions, various well pads in what I would call the Northern part of the Wattenberg Field, so they serve as our acres up in the northern part of the field, and they deliver it to the Lucerne Terminal which is where the Grand Mesa pipeline tick point is, so that's where Grand Mesa begins transporting the crude oil from Lucerne to Cushing, Oklahoma.

Q What services then is Platte River providing to the debtors pursuant to the Platte River transportation services agreement?

A The transportation of the company's produced oil through the pipeline system that they built in the dedicated

debtors consider how long it would take to utilize one of these alternative pipelines?

A Yes, we did. We made the same assumptions from the trucking companies and the bids that we received from them, and then also from the bids we received for the alternative wellhead gathering companies. They provided a timeline for when they thought they could connect into certain wells.

Q And can you describe for the court what the range of timeline is that you received from these alterative pipeline providers?

A Yes, it varies pad by paid. For example, we had some pads that are already connected to oil gathering companies so those pads could be diverted immediately. We have other pads where we share the pad with another operator who was utilizing one of Platte River's competitors. So in that scenario, it would only require building a couple hundred feet of flow line connections and we think that would be done in a month timeframe or less. And then a few of the other pads that are further away, they gave us a schedule of anywhere from three to six months to obtain the necessary rights-of-way that they need and have the pad hooked up to their system. In most cases, for the alternate pad that they would be connecting, it's anywhere from a half mile to a mile and a half connection, so not very long.

Q How does that timing that you heard from the

alternative providers compare to the amount of time it took Platte River to construct its gathering system?

A Well for Platte River to construct its entire gathering system it took, you know, it probably took them eighteen months or so because they were building around ninety miles of pipe, so it could them a long time. However, if Platte River were to be just connecting in pads to their existing infrastructure, it would take them roughly the same amount of time that its taking the third-party company we received a proposal from because that third-party company has already constructed the backbone of their pipeline systems. And all they need to do are build small connectors to connect us into the backbone of that system.

Q Understood. So you considered the timing. Now what about regulatory obligations? How did you factor in the need to obtain permits and rights-of-way -- the alternative provider's need to obtain permits and rights-of-way?

A That was submitted to us in their bid, so we gave them the location of our pads and they looked at the distance from their current infrastructure to the pads that we would like to have connected, and they analyzed quickly the routes that they would probably most likely take to get there. And in their bid, they provided what they thought the timing would be, so that was assumed in that three to six-month timeframe that we've talked about with the alternative providers.

depending on which pad we're looking at. And then those wells would be turned back online once the third-party company was connected to the pads.

Q And in considering shutting in as an option, what did the debtors consider about the loss of oil during that shut-in period?

A The oil isn't necessarily lost during the shut-in period. What happens with wells when you shut them in is they build pressure during their shut-in time. And then when you turn them back online, they're producing at much higher volume then they were when you shut-in, and that incremental volume we call flush production, and that flush production usually makes up the amount of oil that was not produced during the shut-in period in fairly short order. So it's more like the production is being deferred temporarily rather than permanently lost or foregone.

Q Mr. Owens, did you personally prepare a demonstrative for the court to explain how this deferred production works?

A Yes, I made this chart because I think this is very important for the court to understand, the chart of what I was just describing.

Q Can you walk the court through this demonstrative?

A Yes. So I made this chart based off an actual Extraction well that recently was shut-in for about a year. This is a special circumstance and the well was turned back

online.

What I'm showing here is the actual well production in the dashed blue line. That's the actual production of that well for the first year and barrels per day. So it started off at a high amount of barrels per day and then it declined like all wells do over time. This pad was flaring gas and we only had a permit to flare gas for one year, so that is why after one year we had to shut the well in.

The dashed red line is the cumulative oil production, so the total oil that the blue dashed line had made.

The green line is a projection I made based off the data of the oil that well would have continued producing during that next year where it was shut-in. So you can see the green line continues on a declining barrel per day basis in line with the slope of the actual production of the well for the first year. And the cumulative oil production associated with that green line is in the black line. So you can see the black line continuing to grow at a lower and lower slope as the production of the green line continues to decrease.

Well on this particular well, after one year, we turned it back online because it was then connected to a gas pipeline and this would be point three. When we turned the well back online, you can see it was making significantly more oil than it would have been had it not been shut-in

given the projections that I made.

And it just happens in this particular example that that wells made up all of the oil production that it lost within the following twelve months. So if you look at the two cumulative oil lines, you'll see the red cumulative dash line which is the actual production from the well. It increased in tandem with the black line, then it held flat while the well was shut-in, and then it rapidly increased while the oil made its flush production to the point at the end of year three, both wells had accumulated roughly the exact same amount of oil.

So when I say that the oil and the revenue is not gone, it is deferred for the temporary period of shut-in, but then it is recovered at a much accelerated pace at the time the well is turned back to production.

Q Based on this analysis did the debtors determine whether it's better to shut-in the wells where you can't truck and you can't do walk-up shipping for a short period then to stay bound by the Platte River contract?

A It would because, in our view, when the pad or the wells are turned back online, they will be turned back online into a new alternative gathering company that allows us to ship the oil to the Platteville Terminal. So when the flush oil turns back on at those very high rates, we will rapidly recover any loss or deferred revenue because, one, the

$2.5 million dollars. So the total savings based on the bids that we have received would be anywhere from $4.5 to $5.5 million dollars in calendar year 2021.

Q So now let's talk more specifically about the bids. If the debtors are able to successful reject the DJ South TSA and utilize one of these alternatives, how long until there would be a pipeline ready to utilize?

A So, as I mentioned, the alternatives are very close to the Badger central gathering facility. And also, as I mentioned, they only need to connect to one point. They only need to connect to that central gathering facility. They do not need to connect to multiple well pads like the alternative to Platte River would have to do.

So the fact that they only need to build out to one point that is roughly, you know, one to one and a half miles away, we believe in our talks with them that it could be as little as ninety days to as much as 180 days to finish that connection.

Q How does that timing compare to the amount of time it took DJ South to construct its gathering system?

A Again, I think, you can't really compare those two things because for DJ South they were building a large system which I believe is probably 50 miles or so in length, so it took them a long time to do that, where these companies that have submitted bids to us have already built out their

pipeline systems to Platteville, so all they need to do is connect into their existing infrastructure which, as I mentioned, is very close to the Badger central gathering facility.

Q Turning to the last part of your analysis around the transition period, how will the debtors transport their oils over the period of time that it takes to transition to a new pipeline?

A We are unable to truck any oil from the central gathering facility, so we would have to shut-in the wells, at least two of the three pads that produce to the central gathering facility, while we wait for a third-party line to be built or we have the option to produce temporarily as a walk-up shipper under the DJ South tariff filed with Burke's.

Q And we don't need to rehash (indiscernible) with Platte River, but why did the debtors believe that walk-up shipping is a viable alternative?

A We believe it's a viable alternative because it's explicitly allowed under the first tariff and I don't believe can be turned away. But also, Extraction is one of the largest shippers on the DJ South system, and I don't believe that they would willingly forego a large amount of revenue for several months just to prevent us from walk-up shipping.

Q Just so the record is clear with respect to Platte River with walk-up shipping, did the debtors consider whether

to shut-in production; is that right?
A Yes, that would be a scenario.
Q And as I understand it, Extraction, along with its advisors, looked at the financial effect of shutting-in production; is that true?
A We identified the pads and the volumes of production that each specific pad was producing that would not be a Trucking alternative, at least in the very short term. And so, we were aware of the volumes that would have to be moved as a walk-up shipper or temporarily shut-in, awaiting for the third party to connect their gathering system.
Q And Mr. Owens, did Extraction perform any financial analysis of what the financial effect would be of shutting-in that production that you're describing?
A I don't believe it was put into a model for our consideration. It was used, because in most circumstances, we anticipated if the shut-in were to happen, that it would have only been a few months' time frame.

And as we've seen from the demonstrative, we expected to make that revenue up; for example, if it was shut-in one quarter, make it up over the following quarter. But what we ended up assuming was that we would continue shipping as a walk-up shipper on the DJ South and Platte River systems just because we make up the vast majority of revenue that those two pipelines make and we didn't think it would have been a

prudent decision for them to just get rid of all of their revenue because of a court ruling.

If they had the ability to continue making revenue for a period of time at a higher gathering rate, we assume that is what would be in the best interests for their investors.

Q But in terms of a financial effect, if your assumption was wrong and Platte River and DJ South opted to refuse Extraction's production, has Extraction quantified the value of that production that it would need to leave in the ground?

A We did not do that for the reasons that I just mentioned. We believed it would just be a short-term deferral and we believe it's in their best business judgment to continue to make money if they have the ability and they would also have to be going against their FERC tariff to discriminate and not allow a shipper to ship as a walk-up, if the space is available.

Q I understand, Mr. Owens.

And I want to go through the financial effects of shutting that production with you, but before I do it, I just want to make sure I know what Extraction has analyzed when it comes to Platte River and DJ South refusing production.

Would you mind taking a look at the notebook that we sent to you and it's Exhibit 66 that I want to refer you to.

MR. CHRISMAN: And, Your Honor, that's Tab 9 of the notebook that we sent to chambers and to Mr. Owens.

production; is that correct?

A No, we did not look at that as a scenario for the reasons that I mentioned earlier.

Q So, I just want to explore with you, again, the financial effect of Extraction having to shut-in its production if the assumption is incorrect that Extraction has made and in point of fact, DJ South and Platte River refuse to accept Extraction's production, okay.

And let's start with DJ South, because Mr. Brimmage covered a fair bit of this. I think we can go quickly on that.

DJ South transports the production coming through the Badger facility; is that right?

A Yes, that is correct.

Q And as it stands now, Mr. Owens, if the oil isn't transported on the DJ South pipeline out of the Badger facility, Extraction has no other capability to transport it any other way; is that right?

A Currently that is the case.

Q And there's no way to truck that production, like we'll discuss with the Platte River System; is that right?

A That is correct.

Q So, if we go to Page 2 on Exhibit 66, this is the first page of that master schedule that you described --

A Yes.

Q -- this identifies in the left-hand column, Mr. Owens, a list of Extraction's well pads; is that right?

A Correct.

Q And it looks like the very first one that's identified sort of rolls up all of Extraction's wells tied to Badger into one well.

Am I reading that right?

A Yes, it does.

Q And so, the -- in the next column there is an amount identified for the average daily barrels of production that Extraction forecasts over the next six months; is that correct?

A Yes.

Q And so, for the Badger Central Gathering Facility, Extraction anticipates delivering 9,753 barrels of oil per day for the next six-month period; is that correct?

A Yes, it is.

Q And so, if we assumed that a barrel of oil is $40 a barrel, that would be 40 times 9753. So $390,000 a day going through Badger in oil; is that correct?

A No, that is not correct.

Q Well, you'll agree with me that 9,753 barrels of oil times $40 a barrel would be $390,000 of oil a day, right?

A Yes, but I believe the volume being shown here is a gross oil production, which is not the oil production that

Extraction has right and title to.

Q I understand and I do want to talk with you about that. We'll go there next. I want to refer to that, just so we talk on the same page, as gross oil production or gross oil value.

Is that a fair way to describe that?

A Yes, you can do that.

Q Okay. And so, the gross oil value that Extraction anticipates going through Badger over the next six months is $390,000 a day; is that true?

A Yes, that would be correct.

Q And so, it's possible that if Extraction is looking to have an alternative pipeline company connect to Badger to transport its production, it's possible that could take 90 days for that new connection to be in place; is that fair?

A Yes, that is fair.

Q And so, at $390,000 a day over 90 days, that's $35 million in gross oil value, correct?

A Yes, I believe that's correct.

Q I promise the math portion of the exercise will not last long, but I do want to take the Court through the distinction you're making between gross oil value and Extraction's share.

A portion of that $35 million is paid by Extraction to royalty owners, correct?

A A portion, yes; typically around 20 percent.
Q And so, 20 percent of the $35 million would be approximately $7 million, right?
A I believe you have to subtract off the transportation costs from your forty-dollar number, but it would be fairly close to that.
Q Okay. And Extraction has not informed any of its royalty owners that have interests in the wells connected to the DJ South System, that it might shut-in its production for 90 days, has it?
A We have not.
Q (Indiscernible) would not pay them their share of the $7 million for the next 90 days, correct?
A If the wells were shut-in, we would not be paying that.
Q Okay. And a portion of the remainder, after we take out the royalty share, is paid by Extraction to its nonoperating working interest partners in the wells, correct?
A Correct.
Q And that is roughly 30 percent of the remaining amount, correct?
A Yeah, on average, it would be that amount.
Q And just asking you to accept my math so you don't have to do it, it's fair to say that would be roughly $8.4 million to the nonoperating working interest owners, correct?
A Yeah, correct.

Q And I think I understood you explain this to Mr. Brimmage earlier, but just so I'm clear, Extraction has not told any of its non-operating royalty owners that they would be losing this revenue via shut-in, right?

A We have not told our nonoperating working interest partners that that is a potential at this point in time, but we have received numerous complaints from them in the past complaining about the exorbitant fees being charged by the Elevation, DJ South, and Grand Mesa effect, of those rates all stacking on top of each other.

Q And my question wasn't so much about telling them about fees and what you intend to do about it.

My question is, have you told them that you potentially may not be paying them $8.4 million over 90 days?

A We have not officially told them that.

Q And so, the remaining portion of that 35 million over the next 90 days, which I contemplate to be $19.6, that would be Extraction's net-share, prior to costs, correct?

A Yes, I believe so.

Q So, that is the potential lost revenue to Extraction, prior to costs, if Extraction were to shut-in its production of oil connected to the DJ South System over the next 90 days until another gatherer is connected; is that right?

A I would call it deferred oil revenue, rather than lost, but yes.

Q But if it took, Mr. Owens, six months to have an alternate gatherer connect, rather than 90 days, that would be $39.2 million of lost or deferred revenue, just Extraction's share; is that right?

A Correct.

Q And Extraction has not told its lenders that it would be considering shutting-in its production and losing that amount of revenue for the next 90 days or six months, has it?

A It has not been in our models that have been supplied to the vendors so far.

Q And even if the revenue is deferred, rather than lost, that will have an effect on Extraction's month-to-month cash flow, correct?

A On a month-to-month basis, that is correct.

Q Right now, as it stands for DJ South, Extraction does not have a contract in place with another gathering company to connect to the Badger Facility, correct?

A We do not; they're all pending the outcome of this case.

Q And in addition to pending the outcome of the case, is it fair to say that Extraction is evaluating different alternatives from -- based on different proposals?

A As it pertains to the DJ South System, we have received two proposals from two third parties to provide the same transportation service.

realized that Larimer County is not north of Weld County?
A That's Laramie County.
(Laughter)
BY MR. CHRISMAN:
Q That was a good geography lesson.
As I understood your testimony, Mr. Owens, regardless of whether the Platte River wells are in Weld County or Larimer County, Extraction is considering several alternatives for how it's going to transport production from these wells, other than Platte River; is that right?
A Correct.
Q And for some of these wells, the first alternative is Extraction will transport its production using trucks; is that right?
A Yes, that is correct.
Q And a second alternative is that Extraction is going to use a third-party pipeline company that currently has connections to some of its wells already; is that right?
A Correct.
Q And I'm going to -- just incidentally, Mr. Owens, I'm going to do my best to avoid naming that company. I've tried to do it so far, just because I understand that's been designated as confidential, but -- that's why I'm going to speak kind of euphemistically here.
The third alternative is that for some of the wells,

Extraction will continue to use Platte River as a walk-up shipper until it gets a third-party pipeline in place; is that right?

A Correct.

Q And then the fourth alternative is, to the extent any of those other options aren't available, Extraction would shut-in its production until it gets an alternative transportation method in place; is that right?

A Yes, only if the other alternatives were not applicable, which there's a small number of pads for that.

Q If you wouldn't mind, Mr. Owens, taking a look at Defendants' Exhibit 39. This will be Tab 8 in your notebook, Mr. Owens.

THE COURT: So much for not naming the company.

MR. CHRISMAN: Well, that's why we're doing it the old-fashioned way so no one can see it.

(Pause)

BY MR. CHRISMAN:

Q Mr. Owens --

THE COURT: I just want to, just real quick, just impress on everyone to what they already know, no mistake is acceptable. Do not name the company.

MR. CHRISMAN: Your Honor, I'm going to refer to that company, if we admit this exhibit, just as the alternative gathering company or the alternative pipeline

location for trucking, so, yes, I think that would be the correct count.

Q I don't see on this exhibit, unfortunately, the forecasted production for these pads, but these same pads show up on your master schedule that you've included as part of Exhibit 66, right?

A Yes, I believe they were on there.

Q And so if we look at those same 31 pads that are identified as available for trucking on Exhibit 39, we could see the estimated daily production from these pads on Exhibit 66, correct?

A Yes. And I believe on Exhibit 66 there was column that said: Can or Cannot Truck.

Q Okay. And so, if we used that column, Can or Cannot Truck, as a go-by on Exhibit 66, we could determine the number of barrels of oil that Extraction would be intending to truck per day; is that correct?

A I believe so, if you added up all of those lines.

Q Do you know how many barrels of oil Extraction is currently trucking per day?

A Currently I believe other only trucking about the same amount we historically have, which I think is around three to 5,000 barrels a day.

Q Okay. And so, in connection with the pads that Extraction would be trucking additional production, based

upon Exhibit 66, I calculated 6900 barrels of oil per day.

Do you know how many it would be?

A Did you say 6,900?

Q That is correct.

A If that is what the total of all of the ones that say "can truck" are, I believe that would be the correct number.

Q Okay. And then, an average tanker truck holds 166 barrels of production; is that right?

A I thought the number was around 200, or at least that's what I've used in my conversion calculations in the past.

Q That's okay. We can go with 200.

If Extraction is transporting 6900 barrels of oil per day with a tanker truck that holds 200 barrels, that would be just over 34 trucks per day; is that right?

A Yes.

Q And so, if that were on a monthly basis, that would be 1,000 trucks per month, is that right, 1,050?

A Yes.

Q And directing you to the Ardrie pad (phonetic), which has been identified on Exhibit 66, that is a well that currently Extraction would anticipate delivering that production into the pipeline of the alternative gatherer; is that right?

A Yes, that is what I believe will be one of our quickest connections there, but it also appears that it says "can" in

the can/cannot truck column.

Q Okay. And so if, in fact, Extraction were to opt to truck that production instead of using alternative gatherer and its pipeline, that would be an additional 9,300 barrels per day that it would be trucking; is that right?

A Yeah, it would increase the numbers that you just calculated by about two and a quarter times.

Q Okay. If we were just to round to a hundred trucks each day to transport production from Ardrie and the other pads that we've discussed, has Extraction informed Weld County that it could be adding up to a hundred trucks per day to its roads?

A We have not informed Weld County, but most of or all of these wells that say "can" on trucking were permitted in the beginning with the anticipation that the volumes would be trucked forever. So, I believe that was taken into account when the permits were applied for.

Q But, at least for the last three years, these wells have not had their production transported by trucks on Weld County roads, right?

A I believe that's accurate.

For however long they've been producing, they were probably tied into the Platte River System.

Q Other than Weld County, has Extraction informed any other municipality or county that it would be adding those

Exhibit 39.

We can see on Exhibit 39 under, Provider, which wells Extraction is considering using an alternative pipeline provider for to transport its production; is that right?

A Correct.

Q And it's identified by name on Exhibit 39, correct?

A Correct.

Q Now, I think we talked about the fact that some of these well pads already have this provider connected as a joint connection, along with Platte River; is that right?

A On some of the pads, that is correct.

Q And others would require this other provider to physically connect to it.

Those connections don't exist right now; is that right?

A Yes, they would have to physically build out to some of the pads.

Q If we go now to Exhibit 66, in the far right-hand column, we see a start date identified for certain of the pads.

Do you see that?

A Yes.

Q And some of these pads have a start date of October 2020; is that right?

A That is correct.

Q And are these the pads where there is currently a

connection to this other alternative in place?

A Yes, they are.

Q Okay. And we also see a start date for some of these pads as May of 2021.

Are those the pads where Extraction has anticipated using alternative provider, the alternative provider would need to install a connection to those pads in order to begin transporting the production?

A Yes, that's what it appears to show.

Q And so the assumed start date is six months from now; is that right?

A Yes, that's the date referenced.

Q And so, for those pads, it's going to require time for an alternative provider to install connections to the wells, right?

A Correct.

Q And they will have to go through a similar process that you described for connecting to the Badger Facility of obtaining right-of-way agreements, correct?

A Yes, that is correct.

Q And that will take time to obtain, correct?

A Yes, it will.

Q And there's no guarantee because of the time it will take, that that alternative provider will be able to transport this production by May of 2021, right?

summary.

A Tab 9, correct?

Q Exhibit 39.

A That's the Tab Number 9?

Q No, I'm sorry, Mr. Owens. I'm sorry. I misunderstood you.

It's Tab 8.

A Oh, okay.

Q So, Mr. Owens, directing you back to that other provider, we also see a potential alternative as truck (permit).

Do you see that?

A Yes, I do.

Q And for these wells, I understand it to be that -- or well pads -- I understand it to be that trucking is not permitted unless Extraction renegotiates its permits; is that right?

A In some scenarios that is the case; in others, I believe it's referring to we would have to require or apply for a variance in our emissions thresholds because for the temporary period we are trucking, there would be a different amount of emissions, potentially, that are coming from the site; again, that is all based on the volume that the pad is actually producing at the time.

Q I understand.

So, whether it's a permit or an emissions standard, there's some sort of restriction in place that, absent a variance or a modification, Extraction cannot currently transport the production without that; is that right?

A That is what that designation was flagged for by our regulatory team, correct.

Q And for those well pads, Extraction has not applied for any of those modifications or variances, have they?

A I do not believe we have to date.

Q And the relevant governmental entity, whether it be Greeley or whether it be the State Air Quality Division, they don't have any obligation to agree to a variance, do they?

A I am not certain if they have an obligation to or not.

Q Okay. If they don't have an obligation, Extraction's plans for these wells would be to use Platte River System as a walk-up shipper until an alternative is in place; is that right?

A In the event that they refused to grant us a temporary permit, that is correct.

Q And if they don't -- if they do refuse and if Platte River refuses to accept Extraction's production as a walk-up shipper, then that production would be shut-in; is that right?

A Yes, if they were to turn down the revenues associated with it and breach their tariff with FERC, that would be

true.

Q Let me ask you to take a look at the designation on Exhibit 39 that reads: Truck -- and I think it's short for equipment required.

Do you see that?

A Yes, I do.

Q These are well pads, Mr. Owens, I understand to be wells where Extraction would truck, if equipment is added that would allow for trucking from the pads; is that right?

A That is correct.

Q And so, until that equipment is added, if Extraction rejects the Platte River contract, it would plan to use Platte River System as a walk-up shipper; is that correct?

A That could be an option, however, we don't anticipate the time to install the additional equipment on the tanks that are already at the location to take any significant amount of time. It would be very short work that we should be able to complete in less than 30 days.

Q I understand.

But until that equipment is in place, Extraction would need another method to move its production or else it would need to be shut-in; is that right?

A That's correct.

Q And then, finally, going through this list, we reach wells that are marked as "NA."

Do you see that?

A Yes.

Q And I understand that to mean that for those wells, there's no current alternative in place for Platte River System; is that right?

A I do not believe that it means Platte River is the only option. A couple of these tabs on the second page were noted on the third-party company's proposal to build equipment out, too, so I think that might have just meant at the time this was put together, the team had not yet identified what the potential option would be in the interim period.

Q So, let's take one pad for example, on Page 2 of Exhibit 39, this is the Triple Creek pad.

Do you see that?

A Yes.

Q And that's marked as "NA," right?

A Yeah.

Q And is it fair to say that the Triple Creek pad is fairly isolated, *vis-a-vis*, any alternative pipeline company?

A No, I would say that the alternative provider's system, the backbone of their system is the same or very close to the same distance away from the Triple Creek pad as the backbone of the PRN System.

But in the plans, we have seen from the third-party company, they are planning to build out to a pad that is

about a half-mile away to start gathering volumes for one of our peer companies who is drilling and completing a pad in that area.

Q So that company would need to build out the pipeline it's currently building, then need to reach another half-mile to extend to the Triple Creek pad; is that right?

A Yes, that's my recollection.

Q And that would not happen until, setting aside the physical infrastructure, the right-of-way, any permits, that would not happen until, at a minimum, an agreement is signed between Extraction and that pipeline company; is that right?

A I would not anticipate them to start spending capital until an agreement is signed.

Q Okay. And so, if we wanted to determine the financial effect of shutting-in production on the Platte River System, assuming that Platte River refuses Extraction's production, we would identify those pads where Extraction cannot currently truck, determine those volumes, and calculate a gross oil value; is that right?

A Yes.

But, again, that would change. As we've discussed, several of those would be ready to start diverting oil in a matter of weeks, where some might take a little bit longer.

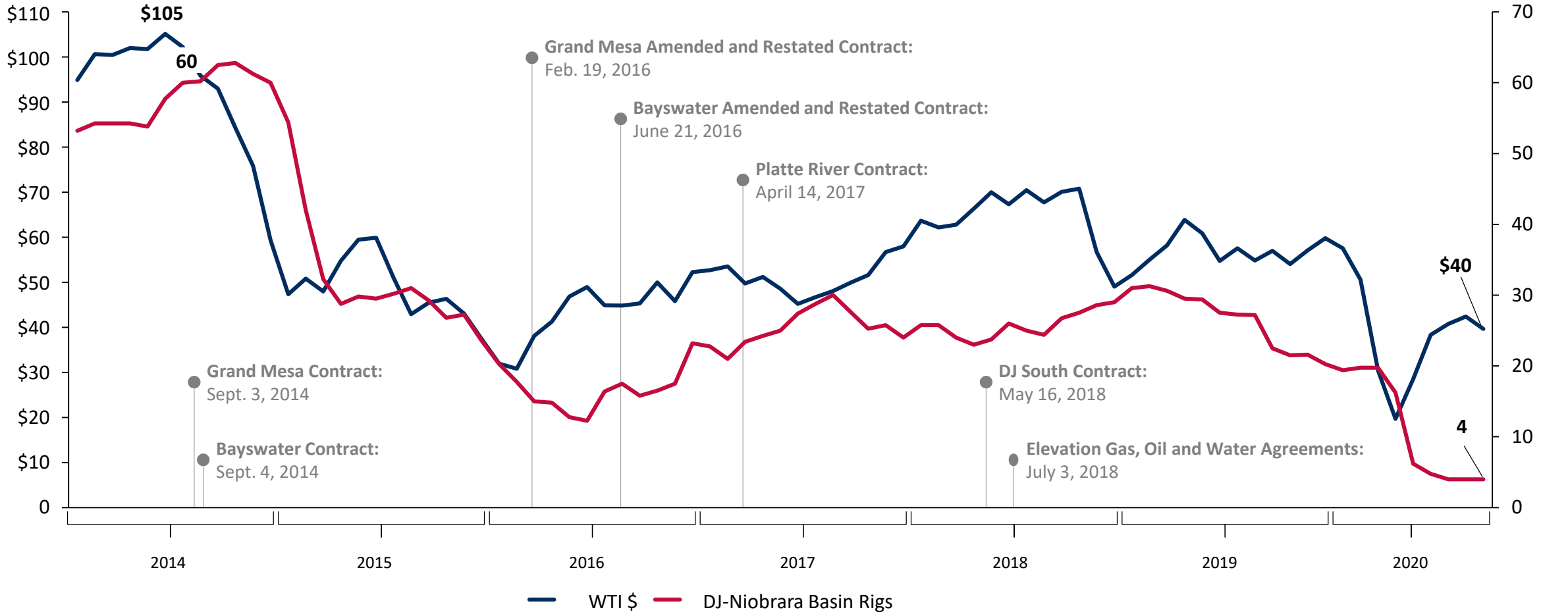
Q And the ones that you're referring to are ones where you think they can get equipment in place within a short

EXHIBIT F

DJ Basin Operating Overview: 2014-2020

Since January 2014, WTI oil prices have declined ~60% while DJ basin rig count has decreased ~90%.

WTI $ / bbl vs. DJ Basin Rig Count
(Monthly Avg from January 2014 to September 2020)



Source: CapIQ Crude Oil – WTI (ICE) Historical Pricing (9/30/2020); Baker Hughes North America Rig Count (9/25/2020)

Contracts Rejection Analysis Overview

	Current Agreement				
Contract	**Counterparty**	**Remaining MVC**	**Term**	**Current Rate**	**2021E Gross Spend ($MM)**
Platte River TSA	Platte River	Current 20 Mbpd After Nov. 2021 10 Mbpd	Oct. 2026	$1.50/bbl	$18.8

Sources

Ex. 42 – Extraction Contracts Tracker 20200813.xlsx ARB_PRM tab

a) MVC – Column I

b) Gross Spend – Column Q rows 27-38

Value in Moving Platte River Gathered Oil via Platteville

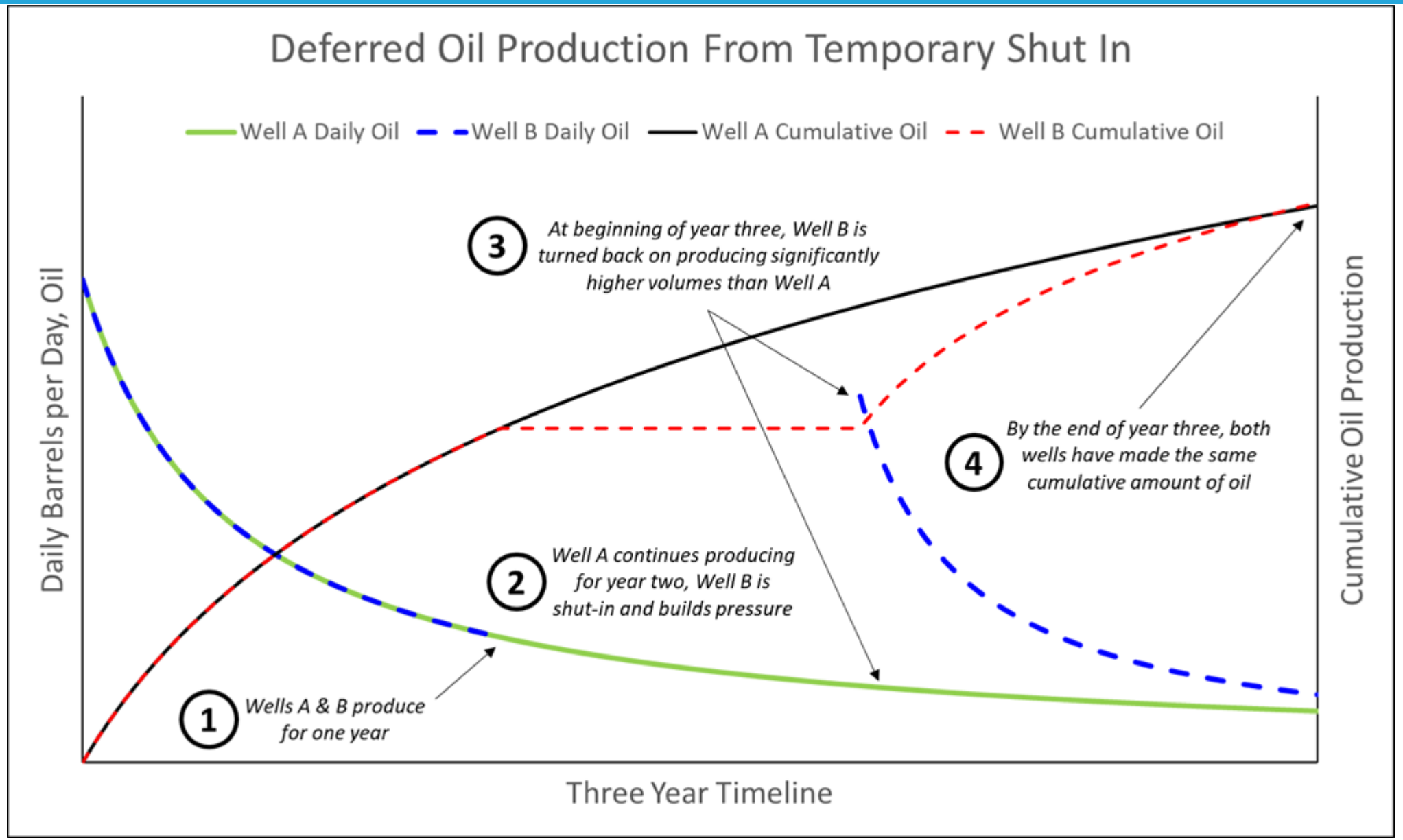
	Current Provider	Lucerne Path (Current)	Platteville Path (Alternative)	Rate Savings via Platteville
Gathering	Platte River (Wellhead to Lucerne, CO)	$1.50/bbl	$1.58/bbl	($0.08)/bbl
Pipeline to Cushing, OK	Grand Mesa (Lucerne, CO to Cushing, OK)	$4.40/bbl	$1.60-$2.20/bbl	$2.20-$2.80/bbl
Total Oil Netback		**$5.90/bbl**	**$3.18-3.78/bbl**	**$2.12-$2.72/bbl**

2021E Gross Volume on Platte River		Rate Savings via Platteville		2021E Savings via Platteville
11.9 MMbbls	x	$2.12-$2.72/bbl	=	**$25.2 - $32.3 MM**

Sources

1. Platteville Path (Alternative) Gathering – **Ex. 57** – Midstream Contract Summary – Business Plan 8/15 column
2. 2021E Platte River Gathered Oil (Gross) – **Ex. 42** – Extraction Contracts Tracker 20200813.xlsx ARB_PRM tab; Calculated from column G rows 27-38, which has average daily volume by calendar month
3. Platteville Path (Alternative) Pipeline to Cushing, OK – **Ex. 56** – Midstream Contract Summary – "Market" column

Deferred Oil Production From Temporary Shut In



Contracts Rejection Analysis Overview

	Current Agreement					Alternatives		2021E Savings with Alternative ($MM)
Contract	Counterparty	Remaining MVC	Term	Current Rate	2021E Gross Spend ($MM)	Rate	2021E Gross Spend ($MM)	
DJ South TSA	DJ South	8-16 Mbpd	Jun. 2029	$1.70/bbl	$7.0	$0.60-$1.00/bbl	$1.5-$2.5	$4.5-$5.5

		Current Agreement		Alternatives	
Fee Type	2021E Gross Volume/Shortfall	Rate	2021E Gross Spend	Rate	2021E Gross Spend
Gathering	2.5 MMbbls	$1.70/bbl	$4.3 MM	$0.60-$1.00/bbl	$1.5-$2.5 MM
Deficiency	1.6 MMbbls	$1.70/bbl	$2.7 MM	n/a	-
Total			**$7.0 MM**		**$1.5-$2.5 MM**

Sources

1. Current Agreement Terms – **Ex. 42** – Extraction Contracts Negotiation Tracker 20200917.xlsx ARB_DJSG tab
   a) Current Contract MVC – Column I
   b) Current Contract daily forecast – Column G
   c) Gross Spend – Column Q rows 27-38
   d) Fee $/Bbl - Column M
   e) Current Contract shortfall (Column J)
2. Alternative Rates - **Ex. 57** – Midstream Contract Summary – Market Rate

Contracts Rejection Analysis Overview

	Current Agreement					Alternatives		2021E Savings with Alternative ($MM)
Contract	Counterparty	Remaining MVC	Term	Current Rate	2021E Gross Spend ($MM)	Rate	2021E Gross Spend ($MM)	
Grand Mesa TSA	Grand Mesa	58 Mbpd	Oct. 2026	$4.40/bbl	$94.0	$1.60-$2.20	$25.3-$34.8	$59.2-$68.7
Bayswater TSA[1]	Grand Mesa	5-6 Mbpd	Oct. 2023	$5.78/bbl	$7.4	N/A (capacity not needed)	-	$7.4

1. Bayswater TSA spend and savings adjusted to exclude spend related to Extraction's capacity allocated to third-party producer

		Current Agreement		Alternatives	
Contract	2021E Gross Volume/Shortfall	Rate	2021E Gross Spend	Rate	2021E Gross Spend
Grand Mesa TSA Fees	15.8 MMbbls	$4.40/bbl	$70.2 MM	$1.60-$2.20/bbl	$25.3-$34.8 MM
Grand Mesa TSA Deficiency	5.4 MMbbls	$4.40/bbl	$23.8 MM	n/a	-
Bayswater TSA Deficiency	1.3 MMbbls	$5.78/bbl	$7.4 MM	n/a	-
Total Spend			**$101.4 MM**		**$25.3-$34.8 MM**

Grand Mesa TSA Sources

1. Current Agreement Terms – **Ex. 37** – Extraction Contracts Negotiation Tracker 20200902.xlsx NGL_GrandMesa tab
   a) Gross Volume – Column H
   b) Gross Volume Shortfall – Column M
   b) MVC – Column J
   d) Gross Spend – Column T rows 27-38
   e) Current Contract Monthly XOG Forecast – Column H
2. Alternative Rates - **Ex. 56** – Midstream Contract Summary – Market Rate

Bayswater TSA Sources

Current Agreement Terms -- **Ex. 37 –** Extraction Contracts Negotiation Tracker 20200902.xlsx NGL_Bayswater tab

a) MVC – Column J
b) Gross Spend – Column R rows 27-38
c) Current Contract Fee Schedule Transportation – Column N
d) Current Contract MVC Shortfall – Column K

Value in Rejecting Elevation Agreements

Scenario	Midstream Provider / Infrastructure			Extraction Company Asset Value (PV-$MM)			
	City/County of Broomfield	Southwest Weld County	Hawkeye Area	Gross Asset Value	Asserted Financial Obligations	Adj Gross Asset Value	Uplift Vs. Scenario One
Scenario One: Current Agreements	Elevation's existing Broomfield system	New connections to Elevation's existing Broomfield system	Future Elevation (No current infrastructure)	$1,421	($362)[1]	**$1,059**	-
Scenario Two: Broomfield Permanent Shut-in	Shut-in	Alternative midstream providers	Alternative midstream providers	$1,304	-	**$1,304**	**$245**
Scenario Three: Broomfield Temp Shut-in / Alternative Build	Extraction new build	Alternative midstream providers	Alternative midstream providers	$1,487	-	**$1,487**	**$428**

1. Includes $67MM of asserted unpaid amount claims by Elevation and estimated $381MM penalty for drilling commitment obligations per page 27 of the Elevation-commissioned Intrepid analysis dated April 6, 2020. Extraction reserves all rights associated with the calculation of the drilling commitment penalty. Amounts discounted at 10%.

Source: **Ex. 55** – Elevation Side-by-Side Analysis

EXHIBIT G

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re	:	Chapter 11
	:	
EXTRACTION OIL & GAS, INC., *et al.*,	:	Case No.: 20-11548 (CSS)
	:	(Jointly Administered)
Debtor.	:	
EXTRACTION OIL & GAS, INC., *et al.*,	:	
	:	
Plaintiff,	:	
	:	
v.	:	Adv. Proc. No.: 20-50833 (CSS)
	:	
PLATTE RIVER MIDSTREAM, LLC, and DJ SOUTH GATHERING, LLC,	:	
	:	
Defendants.	:	

FINDINGS OF FACT AND CONCLUSIONS OF LAW ON PLAINTIFF'S MOTION FOR SUMMARY JUDGMENT AGAINST PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC[1]

INTRODUCTION

This adversary proceeding is one of several arising from the Chapter 11 case of Extraction and its affiliates.[2] The Debtors are in the "upstream" business of extracting hydrocarbons from land in the State of Colorado. In the Chapter 11 case, the Debtors have sought to reject several of what are commonly known as Transportation Services Agreements or TSA's. Broadly speaking, the counterparties to these TSA's are

[1] The Court hereby makes the following findings of fact and conclusions of law pursuant to Fed. R. Bank. P. 7052, which is applicable to this matter by virtue of Fed. R. Bankr. P. 9014. To the extent any findings of fact constitute conclusions of law, they are adopted as such. To the extent any conclusions or law constitute findings of fact, they are adopted as such.

[2] Undefined terms used in this Introduction have the meaning set forth below.

"midstream" pipelines, which transport the Debtors' hydrocarbons to larger "downstream" pipelines or directly to the depot in Cushing, Oklahoma.

In response to the motion to reject, many of the counterparties, including these defendants, have argued that the TSA's cannot be rejected because they include covenants that run with the land. Moreover, they argue that a determination of whether there are covenants that run with the land requires an adversary proceeding. Hence, the Debtors have filed several adversary proceedings in which they have sought a declaratory judgment that the TSA's do not create covenants that run with the land. Currently, before the Court is the Debtor's motion for summary judgment to that effect.[3]

As set forth in detail below, the Court will grant the Debtors' motion for summary judgment. Under Colorado law, to create a covenant running with the land, the parties must intend to create a covenant running with the land and the covenant must touch and concern the land with which it runs. In addition, there must also be privity of estate between the original covenanting parties at the time of the covenant's creation. Under the unambiguous terms of the Platte River Contract, none of the required elements are met—the parties did not intend to create a covenant that runs with the land, the covenant does not touch or concern the land, and there is no privity of the estate. Similarly, under the unambiguous terms of the DJ South Contract, while the parties did intend the dedication and commitment to run with the land, it nonetheless does not touch or concern

[3] The motions to reject are pending in the Chapter 11 case. As of this writing, the motion to reject the Transportation Agreements with Platte River and DJ South are in the midst of an evidentiary hearing.

the land and there is no privity of the estate. Thus, as not all the required elements are present in connection with either contract, no covenant runs with the land.

Finally, while there are several issues discussed below, the central issue before the Court is whether the dedicated and committed interests in the Transportation Agreements touch and concern the land. They do not. The dedications and commitments concern only personal property and do not affect the physical use of real property or closely relate to real property. Throughout the Transportation Agreements, the dedicated and committed interests are used to identify the particular minerals that are subject to, set apart for, pledged or committed to the parties' contractual obligations. They do not convey any interests in real property. Thus, they cannot serve to satisfy the touch and concern the land element of the test to establish a covenant that runs with the land.

THE TRANSPORTATION AGREEMENTS.

This proceeding concerns two agreements for the transportation of crude oil from wells owned and operated by Extraction Oil & Gas, Inc. ("Extraction") north of Denver, Colorado. *Brief in Support of Plaintiff's Motion for Summary Judgment* ("*Extraction MSJ*") (A. D.I. 4) at p. 1-2. Extraction owns leasehold interests in the crude oil and related hydrocarbons, and has contracted with Platte River Midstream, LLC ("Platte River") and DJ South Gathering, LLC ("DJ South" and, collectively with Platte River, the "Defendants") to transport the oil downstream for eventual sale. *Extraction MSJ* (A. D.I. 5-1), Ex. A; (A. D.I. 5-2), Ex. B. The issue presented by *Extraction MSJ* is whether these agreements create covenants running with the land under Colorado law. *Extraction MSJ* (A. D.I. 4) at p. 1.

Extraction and Platte River entered into the First Amended and Restated Transportation Services Agreement (the "Platte River Contract") on April 14, 2017. *Extraction MSJ* Ex. A at p. 1.

On the same day, Extraction and Platte River entered into the April 14, 2017 Storage Tank Lease Option Agreement—a side letter agreement that the parties stated was "intended to be a covenant that runs with the land . . . ." *Reply in Support of the Motion for Summary Judgment* (A. D.I. 23) Ex. 2 at § 7.

Extraction and DJ South entered into the Transportation Services Agreement (the "DJ South Contract," together with the Platte River Contract, the "Transportation Agreements") on May 16, 2018. *Extraction MSJ* (A. D.I. 5-2), Ex. B at p. 1.

The Transportation Agreements are construed in accordance with, and are governed by, Colorado law, without regard to Colorado's conflict of laws provisions. *Extraction MSJ* (A. D.I. 5), Ex. A at § 13.14; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 14.14. The real property implicated by the Transportation Agreements is located within Colorado. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 1.1(t); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 1.1(u).

Extraction did not grant any easement or rights-of-way to the Defendants contemporaneously with the Transportation Agreements. *Defendants' Response in Opposition to the Motion for Summary Judgment* (A. D.I. 21) (the "*Platte River Response*"), Ex. G (A. D.I. 21-7) (Extraction not a party to the contract); Ex. H (A. D.I. 21-8) (same); Ex. N (A. D.I. 21-14) (same); Ex. S (A. D.I. 21-19) (same); Ex. L (A. D.I. 21-12) (right-of-way granted to Platte River on July 17, 2019).

PROCEDURAL BACKGROUND

On June 14, 2020, Extraction and its affiliates filed voluntary petitions under Chapter 11 of the Bankruptcy Code.

On August 11, 2020, the Debtors filed the *Debtors' Second Omnibus Motion for Entry of an Order (I) Authorizing Rejection of Unexpired Leases of Nonresidential Real Property and Executory Contracts Effective as of the Dates Specified Herein and (II) Granting Related Relief* (D.I. 412) (the "*Motion to Reject*").

In connection with the Debtors' chapter 11 cases, Extraction instituted this adversary proceeding by filing its *Complaint for Declaratory Judgment* (A. D.I. 2) against Platte River and DJ South on August 25 (the "*Extraction Complaint*"). The parties dispute whether the Transportation Agreement creates any covenants running with the land. *Extraction Complaint* (A. D.I. 2) at p. 8 and 10.

On the same day, Extraction filed its *Motion for Summary Judgment* (A. D.I. 3).

On September 18, Platte River and DJ South filed their *Response in Opposition to the Motion for Summary Judgment* (A. D.I. 21).

On September 23, Extraction filed its *Reply in Support of the Motion for Summary Judgment* (A. D.I. 23).

On September 30, 2020, the parties argued the motion for summary judgment before this Court.

On October 8, 2020, the parties submitted proposed findings of fact and conclusions of law under the direction of this Court.

CONTRACTUAL TERMS

The Platte River Contract's term ends on "October 31, 2026 unless earlier terminated pursuant to the terms of this Agreement or extended" under the contract's terms. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 4.1.

The DJ South Contract's term ends ten years following the Commencement Date. *Extraction MSJ* (A. D.I. 5-2), Ex. B at §§ 1.1(o) and 5.1.

Section 1.1(o) of the Platte River Contract states: "'Committed Volume' means, subject to Section 3.1, the number of Barrels of Crude Petroleum per day Shipper commits to ship on the Pipeline System as set forth on Schedule A." *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 1.1(o).

Section 1.1(p) of the DJ South Contract states: "'Committed Volume' means, subject to Section 4.1, the number of Barrels of Crude Petroleum per day Shipper commits to ship on the Pipeline System as set forth on Schedule A." *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 1.1(p).

Section 1.1(s) of the Platte River Contract states: "'Crude Petroleum' has the meaning set forth in the Tariff." *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 1.1(s).

Section 1.1(t) of the DJ South Contract also states: "'Crude Petroleum' has the meaning set forth in the Tariff." *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 1.1(t).

The Tariff attached to the Platte River Contract defines "Crude Petroleum" as "the direct liquid product of oil wells, or the indirect liquid petroleum products of oil or gas wells, or a mixture of such products." *Extraction MSJ* (A. D.I. 5-1), Ex. A, (Ex. C) at Item 5.

Section 1.1(bb) of the Platte River Contract states:

> "Interests" means all interests that Shipper (or any of its Affiliates) now or hereinafter owns, controls, acquires or has the right to market (as such marketing rights may change from time to time) in Crude Petroleum of all formations in, under or attributable to the Dedication Area, together with any pool, communitized area or unit, and all interests in any wells, whether now existing or drilled hereafter, on or completed within the Dedication Area, or within any such pool, communitized area or unit, even though such interests may be incorrectly or incompletely stated, all as the same shall be enlarged by the discharge of any burdens or by the removal of any charges or encumbrances to which any of same may be subject as of the Execution Date, and any and all replacements, renewals and extensions or amendments of any of the same; provided, however, that "Interests" shall not include any interest of Shipper or any of its Affiliates that must be offered to a working interest partner pursuant to any applicable agreement with such partner in effect on the Execution Date.

Extraction MSJ (A. D.I. 5-1), Ex. A at § 1.1(bb).

Section 1.1(dd) of the DJ South Contract states:

> "Interests" means all interests that Shipper (or any of its Affiliates) now or hereinafter owns, controls, acquires or has the right to market (as such marketing rights may change from time to time) in Crude Petroleum of all formations in, under or attributable to the Dedication Area, and all interests in any wells, whether now existing or drilled hereafter, on or completed within the Dedication Area, all as the same shall be enlarged by the discharge of any burdens or by the removal of any charges or encumbrances to which any of same may be subject as of the Execution Date, and any and all replacements, renewals and extensions or amendments of any of the same; provided, however, that "Interests" shall not include (i) any interest of Shipper or any of its Affiliates that must be offered to a working interest partner pursuant to any applicable agreement with such partner in effect on the Execution Date or (ii) any interest that Shipper (or any of its Affiliates) now or hereinafter owns, controls, acquires or has the right to market (as such marketing rights may change from time to time) in gas, natural gas liquids or any other gaseous hydrocarbons.

Extraction MSJ (A. D.I. 5-2), Ex. B at § 1.1(dd).

Section 1.1(rr) of the Platte River Contract states: "'Services' means transportation on the Pipeline System of Crude Petroleum for Shipper's account from the origination points set forth on Exhibit A to Lucerne Station and redelivering such Crude Petroleum for Shipper's account into the Grand Mesa Pipeline, any other third party pipeline that connects to the Lucerne Station or any storage tank owned or controlled by Shipper at the Lucerne Station." *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 1.1(rr).

Section 1.1(aaa) of the DJ South Contract states: "'Services' means transportation on the Pipeline System of Crude Petroleum for Shipper's account from the Receipt Points and redelivery of such Crude Petroleum for Shipper's account at the Delivery Points." *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 1.1(aaa).

Section 1.1(ccc) of the Platte River Contract states: "'Total Financial Commitment' means, at a given time, the aggregate of the Fixed Monthly Payments due under this Agreement for all Months of the Term remaining at such time." *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 1.1(ccc).

Section 1.1(kkk) of the DJ South Contract states: "Total Financial Commitment" means, at a given time, the aggregate of the Fixed Monthly Payments due under this Agreement for all Months of the Term remaining at such time." *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 1.1(kkk).

Extraction is required to pay DJ South and Platte River a monthly tariff approved by FERC for the volumes Extraction delivers into the Transportation Systems. Extraction MSJ (A. D.I. 5-1, 5-2), Ex. A at § 5.1 and Ex. B at § 6.1.

Extraction is obligated to make a fixed monthly payment to DJ South and Platte River, regardless of the volumes Extraction delivers. *Id.* at § 6.1 and Ex. B at § 7.1. The fixed monthly payment sets a minimum that Platte River and DJ South will be paid, although it is offset, and usually exceeded, by tariff payments. *Id*.

Section 2.1 of the Platte River Contract states: "Dedication. Subject to Section 2.2, Shipper hereby dedicates and commits to the Services to be provided by Platte River hereunder all of the Interests." *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 2.1.

Section 2.1 of the DJ South Contract states: "Dedication. Subject to Sections 2.2, 2.5 and 2.6, Shipper hereby dedicates and commits to the Services to be provided by Transporter hereunder all of the Interests. Notwithstanding the foregoing, Transporter temporarily releases all of the Interests from the dedication hereunder until (a) with respect to the Interests served by the Badger CGF, the Badger Commencement Date, and (b) with respect to the Interests served by Matador CGF, the Matador Commencement Date." *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.1.

Section 2.5 of the DJ South Contract states:

> **Covenant.** Subject to Section 2.6, the dedication and commitment by Shipper under this Article II shall be deemed an interest that runs with the land in the Dedication Area, and the Parties agree that the dedications and commitments with regard to any Interest existing as of the Effective Date shall be deemed fully vested, and, subject to Section 2.2(b), further agree that the dedications and commitments with regard to future interests in the Interests shall vest upon Shipper's acquiring ownership, control or right to market such Interest(s). Shipper agrees to execute and deliver a memorandum substantially in the form attached hereto as Exhibit C for each of Adams County, Arapahoe County, Weld County, Boulder County, and the City and County of Broomfield to Transporter for recording in the real property records of

each such county in which any portion of the Dedication Area is located in order to evidence the dedication provision of this Article II.

Id. at § 2.5.

There is no provision resembling section 2.5 of the DJ South Contract in the Platte River Contract.

Section 3.1 of the Platte River Contract states:

> **Volume Commitment; Ship or Pay Obligations.** Commencing as of the Commencement Date and continuing thereafter during the Term of this Agreement, Shipper agrees to tender to Platte River for transportation, or otherwise to pay for the transportation of, the Committed Volume in accordance with the tender procedures set forth in the Tariff and the terms of this Agreement; provided, that Shipper's obligation to ship or pay its Committed Volume under this Agreement shall be satisfied in full upon the earlier to occur of (a) Shipper's shipment of eighty five million (85,000,000) Barrels under the terms of this Agreement or (b) by satisfaction of Shipper's Total Financial Commitment. Upon satisfaction of either of such obligations, (i) the Committed Volume shall immediately be reduced to zero and (ii) Shipper may elect to terminate this Agreement upon written notice to Platte River.

Extraction MSJ (A. D.I. 5-1), Ex. A at § 3.1.

Section 4.1 of the DJ South Contract states:

> **Volume Commitment; Ship or Pay Obligations.** Commencing as of the Commencement Date and continuing thereafter during the Term of this Agreement, Shipper agrees to tender to Transporter for transportation, or otherwise to pay for the transportation of, the Committed Volume in accordance with the tender procedures set forth in the Tariff and the terms of this Agreement; provided, that Shipper's obligation to ship or pay its Committed Volume under this Agreement shall be satisfied in full and Shipper's Total Financial Commitment will be zero (0) upon the earlier to occur of (a) Shipper's shipment of one hundred sixteen million, seventy thousand (116,070,000) Barrels under the terms of this Agreement or (b) by satisfaction of Shipper's Total Financial Commitment. Upon satisfaction of either of such obligations, (i) the Committed Volume shall immediately be reduced to zero and (ii) Shipper may elect to terminate this Agreement upon written notice to Transporter.

Extraction MSJ (A. D.I. 5-2), Ex. B at § 4.1.

Section 6.2 of the Platte River Contract states:

> **Total Financial Commitment.** Unless this Agreement is terminated by Shipper due to an Event of Default by Platte River (as more fully described in Section 11.3), or under Section 13.2, upon termination of this Agreement, if, for any reason, Shipper has not paid to Platte River the Total Financial Commitment, Shipper will pay to Platte River the amount due within thirty (30) days following receipt of an invoice from Platte River for such amount due. For the avoidance of doubt, the Total Financial Commitment will be satisfied by payment by Shipper of the aggregate of the Fixed Monthly Payments in accordance with the terms of this Agreement, or at Shipper's option, any payment made by Shipper to accelerate the satisfaction of that obligation. At the end of each Contract Year, Platte River will provide Shipper a statement of dollars accumulated towards the Total Financial Commitment, as well as Barrels shipped to date.

Extraction MSJ (A. D.I. 5-1), Ex. A at § 6.2.

Section 7.2 of the DJ South Contract states:

> **Total Financial Commitment.** Unless this Agreement is terminated by Shipper due to an Event of Default by Transporter (as more fully described in Section 12.3), or under Section 14.2, upon termination of this Agreement, if, for any reason, Shipper has not paid to Transporter the Total Financial Commitment, Shipper will pay to Transporter the amount due within thirty (30) days following receipt of an invoice from Transporter for such amount due; provided, however, that if Shipper's failure to pay the Total Financial Commitment is due to Transporter's failure to accept volumes nominated by Shipper, Shipper shall have the option to extend the Term of this Agreement for such period of time as required to pay the Total Financial Commitment at the same Volume Commitment level as in effect on the date Shipper exercises such extension option. For the avoidance of doubt, the Total Financial Commitment will be satisfied by payment by Shipper of the aggregate of the Fixed Monthly Payments in accordance with the terms of this Agreement, or at Shipper's option, any payment made by Shipper to accelerate the satisfaction of that obligation. At the end of each Contract Year, Transporter will provide Shipper a statement of dollars accumulated towards the Total Financial Commitment, as well as Barrels shipped to date.

Extraction MSJ (A. D.I. 5-2), Ex. B at § 7.2.

Section 6.6 of the Platte River Contract states:

> **Title.** Shipper warrants that it possesses either title to, or the right to deliver to Platte River for transportation hereunder, all of the Crude Petroleum delivered or caused to be delivered by Shipper to the Pipeline System for shipment under this Agreement. Shipper warrants that all Crude Petroleum delivered by or for Shipper to the Pipeline System for shipment under this Agreement is free from all liens, security interests, and adverse claims of every kind and agrees to release, indemnify, defend and hold Platte River and its affiliate and subsidiary companies and their respective shareholders, members, partners, directors, managers, officers, employees, agents and representatives harmless from all suits, actions, claims, judgments, debts, accounts, damages, costs, liabilities, losses, and expenses arising from or out of adverse claims of any or all persons, including Governmental Authorities, as to title to, or otherwise claiming an interest in or right to payment on account of, such Crude Petroleum including, but not limited to, royalties and other charges payable with respect thereto. Platte River will have the right to reject any Crude Petroleum that, when tendered for transportation on the Pipeline System, is the subject of litigation or that is encumbered by any lien, security interest, or other form of burden, and Platte River may require Shipper to provide satisfactory evidence of unencumbered title prior to accepting deliveries of Crude Petroleum from Shipper.

Extraction MSJ (A. D.I. 5-1), Ex. A at § 6.6.

Section 7.6 of the DJ South Contract states:

> **Title.** Shipper warrants that it possesses either title to, or the right to deliver to Transporter for transportation hereunder, all of the Crude Petroleum delivered or caused to be delivered by Shipper to the Pipeline System for shipment under this Agreement. Shipper warrants that all Crude Petroleum delivered by or for Shipper to the Pipeline System for shipment under this Agreement will be delivered to Shipper free of all liens, security interests, and adverse claims of every kind (other than statutory liens and liens in favor of Persons who have provided debt financing to Shipper) and agrees to release, indemnify, defend and hold Transporter and its affiliate and subsidiary companies and their respective shareholders, members, partners, directors, managers, officers, employees, agents and representatives harmless from all suits, actions, claims, judgments, debts, accounts, damages, costs, liabilities, losses, and expenses arising from or out of adverse claims of any or all persons, including Governmental Authorities, as to

title to, or otherwise claiming an interest in or right to payment on account of, such Crude Petroleum including, but not limited to, royalties and other charges payable with respect thereto. Transporter will have the right to reject any Crude Petroleum that, when tendered for transportation on the Pipeline System, is the subject of litigation or that is encumbered by any lien, security interest, or other form of burden, and Transporter may require Shipper to provide satisfactory evidence of unencumbered title prior to accepting deliveries of Crude Petroleum from Shipper.

Extraction MSJ (A. D.I. 5-2), Ex. B at § 7.6.

Section 6.7 of the Platte River Contract states:

Custody. Shipper will be deemed to be in exclusive control and possession of the Crude Petroleum delivered by or for Shipper to the Pipeline System under this Agreement prior to and until such Crude Petroleum is delivered into the inlet flange of LACT units provided by Platte River for delivery into the Pipeline System, and after redelivery of such Crude Petroleum to Shipper or its designee at the Lucerne Station. Platte River shall be in exclusive control and possession of (although title will remain in Shipper or other person for whom Shipper has the right to transport Crude Petroleum) Crude Petroleum delivered by or for Shipper to the Pipeline System for shipment under this Agreement after delivery thereof into the Pipeline System and prior to redelivery thereof to Shipper or its designee at the Lucerne Station. The Party that is in exclusive control and possession of the Crude Petroleum will be responsible for all injury, damage, pollution, or contamination, or violation of or the need to comply with Applicable Law caused thereby, except (a) to the extent attributable to the gross negligence or willful misconduct of the other Party and (b) to the extent caused by the failure of the Crude Petroleum to meet the quality specifications described in the Tariff. Further, the Party having responsibility for Crude Petroleum under the preceding sentences (except with respect to Platte River to the extent such Crude Petroleum does not meet the specification set forth in Item No. 30 of the Tariff), will release, defend, indemnify, and hold the other Party, its Affiliates, and its and their officers, employees, and agents harmless from and against any and all Claims arising from (i) personal injury, death, damage, pollution or contamination, or violation of or the need to comply with any Applicable Law, caused by Crude Petroleum deliverable under the Tariff while such Crude Petroleum was in the exclusive control and possession of the Party as set forth in this Section 6.7; or (ii) personal injury, death, damage, pollution or contamination, or violation of or the

need to comply with any Applicable Law, arising out of the Party's facilities or operations WITHOUT REGARD TO WHETHER THE ACT, OCCURRENCE, OR CIRCUMSTANCE GIVING RISE TO THE INDEMNIFICATION OBLIGATION IS THE RESULT OF THE SOLE, ACTIVE, PASSIVE, CONCURRENT, OR COMPARATIVE NEGLIGENCE, STRICT LIABILITY, BREACH OF DUTY (STATUTORY OR OTHERWISE), OR OTHER FAULT OF OR VIOLATION OF ANY APPLICABLE LAW BY THE INDEMNIFIED PERSON, PROVIDED THAT NO INDEMNIFICATION WILL BE APPLICABLE TO THE EXTENT OF ANY GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE INDEMNIFIED PERSON.

Extraction MSJ (A. D.I. 5-1), Ex. A at § 6.7.

Section 7.7 of the DJ South Contract states:

Custody. Shipper will be deemed to be in exclusive control and possession of the Crude Petroleum delivered by or for Shipper to the Pipeline System under this Agreement prior to and until such Crude Petroleum is delivered into the inlet flange of LACT units provided by Shipper for delivery into the Pipeline System, and after redelivery of such Crude Petroleum to Shipper or its designee at the Delivery Points. Transporter shall be in exclusive control and possession of (although title will remain in Shipper or other person for whom Shipper has the right to transport Crude Petroleum) Crude Petroleum delivered by or for Shipper to the Pipeline System for shipment under this Agreement after delivery thereof at the Receipt Point and prior to redelivery thereof to Shipper or its designee at the Delivery Points. The Party that is in exclusive control and possession of the Crude Petroleum will be responsible for all injury, damage, pollution, or contamination, or violation of or the need to comply with Applicable Law caused thereby, except (a) to the extent attributable to the gross negligence or willful misconduct of the other Party and (b) to the extent caused by the failure of the Crude Petroleum to meet the quality specifications described in the Tariff. Further, the Party having responsibility for Crude Petroleum under the preceding sentences (except with respect to Transporter to the extent (1) such Crude Petroleum does not meet the specification set forth in Item No. 30 of the Tariff, (2) Transporter did not knowingly accept such off-specification Crude Petroleum, and (3) the injury or other loss was caused by such Crude Petroleum failing to meet the specifications), will release, defend, indemnify, and hold the other Party, its Affiliates, and its and their officers, employees, and agents harmless from and against any and all Claims arising from (i) personal injury, death, damage, pollution or contamination, or violation of or the

need to comply with any Applicable Law, caused by Crude Petroleum deliverable under the Tariff while such Crude Petroleum was in the exclusive control and possession of the Party as set forth in this Section 7.7; or (ii) personal injury, death, damage, pollution or contamination, or violation of or the need to comply with any Applicable Law, arising out of the Party's facilities or operations WITHOUT REGARD TO WHETHER THE ACT, OCCURRENCE, OR CIRCUMSTANCE GIVING RISE TO THE INDEMNIFICATION OBLIGATION IS THE RESULT OF THE SOLE, ACTIVE, PASSIVE, CONCURRENT, OR COMPARATIVE NEGLIGENCE, STRICT LIABILITY, BREACH OF DUTY (STATUTORY OR OTHERWISE), OR OTHER FAULT OF OR VIOLATION OF ANY APPLICABLE LAW BY THE INDEMNIFIED PERSON, PROVIDED THAT NO INDEMNIFICATION WILL BE APPLICABLE TO THE EXTENT OF ANY GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF THE INDEMNIFIED PERSON.

Extraction MSJ (A. D.I. 5-2), Ex. B at § 7.7.

Section 13.9 of the Platte River Contract states:

Successors and Assignability. This Agreement shall inure to the benefit of and be binding upon the Parties hereto and their respective permitted successors and assigns. This Agreement shall not be assigned or transferred in whole or in part by either Party except upon the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Notwithstanding the foregoing, either Party may make a Permitted Transfer of this Agreement at any time, without the other Party's consent. In the event of any assignment made by Shipper as a Permitted Transfer, Shipper shall remain obligated for all obligations under this Agreement jointly and severally with its assignee unless such assignee demonstrates sufficient financial viability and creditworthiness equivalent or better than Shipper or otherwise sufficient to fulfill the obligations of Shipper under this Agreement to the reasonable satisfaction of Platte River. With respect to all other assignments to which Platte River has consented pursuant to this Section 13.9, Shipper shall not remain obligated for all obligations under this Agreement jointly and severally with its assignee.

Extraction MSJ (A. D.I. 5-1), Ex. A at § 13.9.

Section 14.9 of the DJ South Contract states:

Successors and Assignability. This Agreement shall inure to the benefit of and be binding upon the Parties hereto and their respective

> permitted successors and assigns. This Agreement shall not be assigned or transferred in whole or in part by either Party except upon the prior written consent of the other Party, which consent shall not be unreasonably withheld, conditioned, or delayed. Notwithstanding the foregoing, either Party may make a Permitted Transfer of this Agreement at any time, without the other Party's consent. In the event of any assignment made by Shipper as a Permitted Transfer, Shipper shall remain obligated for all obligations under this Agreement jointly and severally with its assignee unless such assignee demonstrates, consistent with the Tariff, sufficient financial viability and creditworthiness equivalent or better than Shipper or otherwise sufficient to fulfill the obligations of Shipper under this Agreement to the reasonable satisfaction of Transporter. With respect to all other assignments to which Transporter has consented pursuant to this Section 14.9, Shipper shall not remain obligated for all obligations under this Agreement jointly and severally with its assignee.

Extraction MSJ (A. D.I. 5-2), Ex. B at § 14.9.

CONCLUSIONS OF LAW

JURISDICTION AND VENUE

The Court has jurisdiction over this matter. 28 U.S.C. §§ 157 and 1334.

No party has challenged the Court's jurisdiction. *Extraction Complaint* (A. D.I. 2); *Platte River Response* (A. D.I. 21). Extraction consents to entry of a final order or judgment by this Court in this proceeding; however, pursuant to Local Rule 7012-1, Platte River and DJ South do not consent to the entry of a final order or judgment by this Court.

DECLARATORY JUDGMENT

Declaratory judgment is appropriate because the parties dispute whether the Transportation Agreements create any covenants running with the land in connection with the Debtors' *Motion to Reject* the Transportation Agreements. 28 U.S.C § 2201 (a) ("In a case of actual controversy within its jurisdiction . . . any court of the United States, upon the filing of an appropriate pleading, may declare the rights and other legal

relations of any interested party seeking such declaration, whether or not further relief is or could be sought.").

LEGAL STANDARD

To succeed on summary judgment, the movant must show that "the pleadings, the discovery and disclosure materials on file, and any affidavits show that there is no genuine issue as to any material fact and that the movant is entitled to judgment as a matter of law." *In re Maxus Energy Corp.*, 615 B.R. 62, 68 (Bankr. D. Del. 2020) (quoting *Celotex Corp. v. Catrett*, 477 U.S. 317, 322 (1986)).

The movant "bears the burden of proving that no genuine issue of material fact exists." *In re Quintas Corp.*, 397 B.R. 710, 714 (Bankr. D. Del. 2008) (citation omitted).

In determining whether summary judgment is appropriate, the court accepts all evidence presented by the non-movant as true and draws all inferences in the non-movants' favor and against summary judgment. *See In re LTC Holdings, Inc.*, 597 B.R. 554, 559 (Bankr. D. Del. 2019) (citing *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 255 (1986)).

"[W[here the record could leave reasonable minds to draw conflicting inferences, summary judgment is improper and the action must proceed to trial." *In re Maxus Energy Corp.*, 615 B.R. at 69 (citations and internal quotations omitted).

GOVERNING LAW

Colorado law governs the substantive real property questions in this case. *Wolf v. Burke*, 32 P. 427, 429 (Colo. 1893) ("[T]he rights and titles to real property are governed by the law of the situs . . . ."); *United States v. Novotny*, 184 F. Supp. 2d 1071, 1087 (D. Colo.

2001) ("Colorado law applies to issues relating to the conveyance and ownership of real property located within Colorado.") (citation simplified).

SUMMARY JUDGMENT

Summary judgment is appropriate when there are no genuine issues of material fact. Fed. R. Civ. P. 56(a) (noting the "[C]ourt shall grant summary judgment if the movant shows that there is no genuine dispute as to any material fact and the movant is entitled to judgment as a matter of law"); *Celotex Corp. v. Catrett*, 477 U.S. 317, 327 (1986) ("The Federal Rules of Civil Procedure have for almost 50 years authorized motions for summary judgment upon proper showings of the lack of a genuine, triable issue of material fact."); *Tamarind Resort Assocs. v. Gov't of Virgin Islands*, 138 F.3d 107, 110 (3d Cir. 1998) ("[I]t is a fundamental principle of contract law that 'disputes involving the interpretation of unambiguous contracts are resolvable as a matter of law, and are, therefore, appropriate cases for summary judgment.'").

In Colorado, the "[i]nterpretation and construction of covenants is a question of law." *Holiday Acres Prop. Owners Ass'n, Inc. v. Wise*, 998 P.2d 1106, 1108 (Colo. App. 2000), *as modified on denial of reh'g* (July 6, 2000); *accord Pulte Home Corp., v. Countryside Cmty. Ass'n, Inc.*, 382 P.3d 821, 826 (Colo. 2016) ("Covenants and other recorded instruments, like contracts, should be construed as a whole "seeking to harmonize and give effect to all provisions so that none will be rendered meaningless.").

The Defendants have not raised any genuine issue of material fact concerning whether the Transportation Agreements create covenants running with the land. *Platte River Response* (A. D.I. 21).

Any ambiguity concerning whether the terms of the Transportation Agreements created covenants running with the land would be resolved in favor of the unrestricted use of the land. *B.B. & C. P'ship v. Edelweiss Condo. Ass'n*, 218 P.3d 310, 315 (Colo. 2009) ("When the covenant is unclear, courts resolve all doubts against the restriction and in favor of free and unrestricted use of property.").

The Transportation Agreements' terms are unambiguous. *Am. Family Mut. Ins. Co. v. Hansen*, 375 P.3d 115, 120 (Colo. 2016) ("A contractual term is ambiguous 'if it is susceptible on its face to more than one reasonable interpretation.'").

COVENANTS RUNNING WITH THE LAND

The unambiguous terms of the Transportation Agreements do not create any covenants running with the land. *Extraction MSJ* (A. D.I. 4), Ex. A; *Extraction MSJ* (A. D.I. 5-2), B.

Under Colorado law, "[u]nlike personal covenants, which operate like a general contract provision and bind only the actual parties to the covenant, real covenants "run with the land" and burden or benefit successors in interests." *Cloud v. Ass'n of Owners*, 857 P.2d 435, 440 (Colo. App. 1992).

A real covenant, or covenant running with the land, creates "an equitable property interest in the burdened land." 9 Powell, Powell on Real Property § 60.01; *see also* Restatement (Third) of Property (Servitudes) § 7.9 (2000) (servitudes, such as covenants running with the land, are not a lien or executory contract but rather, "an interest in land"); *id.* at § 1.4 (abolishing distinction between the terms "real covenant" and "equitable servitude" as they both "describe servitudes encompassed within the term

'covenant that runs with the land'"). Colorado courts long have recognized that a covenant running with the land is a burden on real property. *See Farmers' High Line Canal & Reservoir Co. v. N.H. Real Estate Co.*, 92 P. 290, 294 (Colo. 1907) ("A covenant which runs with the land is a promise, the effect of which is to bind the promisor and his lawful successors to the burdened land for the benefit of the promisee and his lawful successors to the benefited land. According to this the covenant binds the person of the owner of the burdened land, provided he comes by his title legally, and benefits the owner of the benefited land, provided he comes by his title legally.") (citation and internal quotations omitted); *see also In re Lonesome Pine Holdings, LLC*, 2011 Bankr. LEXIS 5775, at *9 (Bankr. D. Colo. Sept. 1, 2011) ("restrictions that run with the land create equitable interests") (citation and internal quotations omitted).

Colorado law disfavors the creation of covenants running with the land as a derogation of the common law's preference for the free alienability of land. *Nelson v. Farr*, 354 P.2d 163, 166 (Colo. 1960) ("[A]s a fundamental principle of law of real property, restrictions on the alienation and use of land are not favored, and all doubt should be resolved in favor of the free use of property . . . .'Restrictions on the use of property, being in derogation of the fee conveyed, will not be extended by implication to include anything not clearly expressed.'").

In addition, to create a covenant running with the land, the parties must intend to create a covenant running with the land and the covenant must touch and concern the land with which it runs. *Reishus v. Bullmasters, LLC*, 409 P.3d 435, 440 (Colo. 2016) (concerning intent and touch and concern).

Finally, to create a covenant running with the land, there must also be privity of estate between the original covenanting parties. *Taylor v. Melton*, 274 P.2d 977, 988–89 (Colo. 1954) (requiring privity of estate between the covenanting parties); *Farmers' High Line Canal & Reservoir Co.*, 92 P. at 293 (same); *Hottell v. Farmers' Protective Ass'n*, 53 P. 327, 330 (Colo. 1898) (same).

Failure to satisfy any of the three elements needed to create a covenant running with the land means that a covenant cannot run with the land as a matter of law. *See Cloud v. Ass'n of Owners,* 857 P.2d 435, 440 (Colo. App. 1992) ("Even if there is an intent to make a covenant run with the land, the covenant must still 'touch and concern' the land, that is, it must closely relate to the land, its use, or its enjoyment.").

Contracting parties cannot create covenants running with the land by agreement alone; intent of the parties is necessary for a covenant to run with the land, but not sufficient. *Id*. ("Even if there is an intent to make a covenant run with the land, the covenant must still 'touch and concern' the land, that is, it must closely relate to the land, its use, or its enjoyment."); *Lookout Mountain Paradise Hills Homeowners' Ass'n v. Viewpoint Assocs.*, 867 P.2d 70, 74 (Colo. App. 1993) ("In order for a covenant to run with the land, not only must the parties to the covenant intend that it do so . . . but the covenant must 'touch and concern' the land.").

I. Intent.

The parties dispute whether the Platte River Contract was intended to create a covenant running with the land. Extraction argues that the absence of express language in the Platte River Contract evidences the parties' lack of intent. *See Extraction MSJ* (A.

D.I. 4) at p. 11-12. Platte River and DJ South argue that although there is no express language, the contract as a whole, as well as the underlying purpose of the Transportation Agreements, demonstrate an intent to create a covenant running with the land and bind successors in interest. *See Platte River Response* (A. D.I. 21), at p. 16-22.

Platte River further argues that the absence of language in the Platte River Contract expressly stating that it creates a covenant running with the land is not dispositive under Colorado law, as a covenant running with the land need not "be expressed in specific or magical terms." *TBI Expl. v. Belco Energy Corp.*, No. 99-10872, 2000 WL 960047, at *4 (5th Cir. June 14, 2000) (conducting a survey of Colorado case law). Rather, Colorado courts look at agreements "as a whole…, giving effect to all provisions contained therein." *Lookout Mtn.*, 867 P.2d at 75 (citation omitted).

To create covenants running with the land, the parties must express their intent to create a covenant running with the land in clear and unambiguous terms. *TBI Explr.*, 2000 WL 960047, at *4 (applying Colorado law and stating "[I]n the cases that have recognized a covenant running with the land, the covenants were in express terms."); *MidCities Metro. Dist. No. 1 v. U.S. Bank Nat. Ass'n*, 12-CV-03322-LTB, 2013 WL 3200088, at *3 (D. Colo. June 24, 2013) (applying Colorado law and noting that if a covenant is ambiguous, the Court must "resolve all doubts against the restriction and in favor of free and unrestricted use of property.").

The Platte River Contract was not intended to create a covenant running with the land. The Platte River Contract does not contain any language evincing a clear intent to create a covenant running with the land. *See, e.g., Lookout Mountain* 867 P.2d at 75; *TBI*

Explr., *2000 WL 960047*, at *4 (applying Colorado law and stating "[I]n the cases that have recognized a covenant running with the land, the covenants were in express terms."). Defendants' attempts to manufacture a genuine issue of material fact are based on inappropriate extrinsic evidence and, in any event, are unavailing.

Reference to successors and assigns in Section 13.9 of the Platte River Contract is insufficient to demonstrate an intent to create a covenant that runs with the land because the language does not purport to bind successors-to-title to any identified real property, but simply relates to contractual successors and assigns to the Platte River Contract. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 13.9; *see Villa Sierra Condo. Ass'n v. Field Corp.*, 878 P.2d 161, 167 (Colo. App. 1994).

The DJ South Contract contains this same provision despite also containing covenant running with the land language. *See Extraction MSJ* (A. D.I. 5-2), Ex. B at § 14.9 ("This Agreement shall inure to the benefit of and be binding upon the Parties hereto and their respective permitted successors and assigns.") *and* § 2.5 ("[T]he dedication and commitment . . . shall be ***deemed an interest that runs with the land*** . . . .") (emphasis added).

In contrast to the Platte River Contract, the DJ South Contract similarly contains the requisite language to show intent to create a covenant running with the land. *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.5 ("[T]he dedication and commitment . . . shall be ***deemed an interest that runs with the land*** . . . .") (emphasis added).

The only covenant in the DJ South Contract that the parties clearly expressed an intent to run with the land is the dedication and commitment for the performance of the

transportation services obligations. *Id*. ("[T]he dedication and commitment by [Extraction] under this Article II shall be deemed an interest that runs with the land in the Dedication Area . . . .").

The parties intended the dedication and commitment in the DJ South Contract to run with Extraction's mineral estates. *Extraction MSJ* (A. D.I. 5-2), Ex. B at §§ 1.1(dd) ("'Interests' means all interests that Shipper (or any of its Affiliates) now or hereinafter owns, controls, acquires or has the right to market (as such marketing rights may change from time to time) in Crude Petroleum of all formations in, under or attributable to the Dedication Area, and all interests in any wells, whether now existing or drilled hereafter, on or completed within the Dedication Area . . . .") and § 2.1 ("Shipper hereby dedicates and commits to the Services to be provided by Transporter hereunder all of the Interests.").

The parties did not express an intent to allow any other covenants in the DJ South Contract to run with the land. *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.5.

Because the Platte River Contract does not clearly evince an intent for any covenants contained therein to run with the land and bind successors-to-title to any estate in real property, the Platte River Contract does not create covenants that run with the land as a matter of Colorado law. *TBI Explr. v. Belco Energy Corp.*, No. 99-10872, 2000 WL960047, at *4 (5th Cir. June 14, 2000) (applying Colorado law and stating "[I]n the cases that have recognized a covenant running with the land, the covenants were in express terms.").

II. Touch and Concern.

The parties dispute whether the Transportation Agreements touch and concern the land. Extraction argues that the Transportation Agreements do not touch and concern the land because the dedications only identify crude petroleum from particular lands that are subject to the agreements and because they affect only personal property. *Extraction MSJ* (A. D.I. 4), at p. 24. Defendants argue the Transportation Agreements touch and concern the land because they both benefit and burden Extraction's real property interests. *Platte River Response* (A. D.I. 21), at p. 22-24.

To satisfy touch and concern, the covenant intended to run with the land—here, the dedication and commitment—must closely relate to the estate in real property with which it is intended to run (here, Extraction's mineral estate), its use, or enjoyment. *Reishus v. Bullmasters, LLC*, 409 P.3d 435, 440 (Colo. 2016) (noting "[a] covenant touches and concerns the land if it 'closely relate[s] to the land, its use, or enjoyment.'").

"The 'touch and concern' requirement is fulfilled when the covenant operates to benefit the physical use of the land . . . ." *Bigelow v. Nottingham*, 833 P.2d 764, 767 (Colo. App. 1991), *rev'd in part sub nom. on other grounds Haberl v. Bigelow*, 855 P.2d 1368 (Colo. 1993) (noting a subordination agreement was a personal covenant that did not run with the land because "the parties' entitlement to physical use of the land was not increased, nor was improvement made to the land as a result of subsequent loan proceeds").

Colorado generally follows the traditional common law approach to the touch and concern element. 3 Tiffany Real Property § 854 (3d ed. 2015) ("An important test for

distinguishing a real or running covenant from a merely personal or collateral one, is whether or not the covenant so closely relates to the land or estate granted . . that it may be said to 'touch and concern' it.").

Touch and concern is an objective analysis of a covenant's effect upon land and the element does not turn on party intent or word choice. *Cloud v. Ass'n of Owners,* 857 P.2d 435, 440 (Colo. App. 1992) ("Even if there is an intent to make a covenant run with the land, the covenant must still 'touch and concern' the land, that is, it must closely relate to the land, its use, or its enjoyment."); *In re Sabine Oil & Gas Corp.*, 567 B.R. 869, 875 (S.D.N.Y. 2017), *aff'd,* 734 Fed. Appx. 64 (2d Cir. 2018) ("[T]he appellants have not purchased the minerals underlying the Dedicated Areas but, again, have merely agreed to provide services to the minerals' owner. The logical extension of Nordheim's argument—that any agreement relating to minerals in the ground constitutes the conveyance of a real property interest—is not supported by the cited caselaw."); 21 C.J.S. Covenants § 34 ("[T]he intent of the parties is not dispositive, insofar as obligations arising from restrictive covenants that are inherently personal cannot be made appurtenant to the land[.]"); 9 Richard R. Powell, Powell on Real Property § 60.04(3)(a) ("The touch and concern requirement is the only essential requirement for the running of covenants which focuses on an objective analysis of the contents of the covenant itself rather than the intentions of and relationships between the parties.").

The dedications and commitments in Sections 2.1 were "to the Services to be provided" by Platte River and DJ South under the Transportation Agreements (*i.e.*, the transportation of certain produced crude petroleum from Receipt Points to Delivery

Points, or to Lucerne Station). *Extraction MSJ* (A. D.I. 5-1), Ex. A at §§ 1.1(rr) and 2.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at §§ 1.1(aaa) and 2.1.

Under the Transportation Agreements, Platte River and DJ South committed to transport a certain volume of Extraction's crude petroleum in exchange for a contractual fee. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 3.1 ("Commencing as of the Commencement Date and continuing thereafter during the Term of this Agreement, Shipper agrees to tender to Platte River for transportation, or otherwise to pay for the transportation of, the Committed Volume in accordance with the tender procedures set forth in the Tariff and the terms of this Agreement); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 4.1 (same but respecting DJ South).

The dedications in Section 2.1 of both Transportation Agreements do not change the nature of the covenants contained in the Transportation Agreements; they simply identify the produced minerals subject to the parties' contractual obligations. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 2.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.1; *In re Sabine Oil & Gas Corp.*, 547 B.R. 66, 76 (Bankr. S.D.N.Y. 2016), *aff'd,* 567 B.R. 869 (S.D.N.Y. 2017), *aff'd*, 734 Fed. Appx. 64 (2d Cir. 2018) (holding a similar contract merely "identif[ies] and delineat[es] the [parties'] contractual rights and obligations").

In the Transportation Agreements, Defendants dedicated and committed "to the Services to be provided" under the Transportation Agreements "all of the Interests." *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 2.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.1.

Defendants argue that, although Extraction claims the dedication relates only to personal property in the form of produced crude oil, the Transportation Agreements

clearly dedicate more than Extraction's current production. Rather, they dedicate all of Extraction's "interests" "in, under, or attributable to" the Dedication Areas. *Id.*

In support of this argument, Defendants cite to the recent decision by the Colorado Bankruptcy Court that a production dedication with similar language touched and concerned the land under Utah law. *See In re Badlands Energy, Inc.*, 608 B.R. 854, 869 (Bankr. D. Colo. 2019). The court explained because the "dedicated reserves" under the gathering agreement were defined broadly to include "the interest of Producer in all Gas reserves in and under" the dedicated area, the gathering agreement encompassed real property. *Id.* (emphasis in original). As in Utah, "real property" under Colorado law includes non-extracted minerals. *See Bill Barrett Corp.*, 2018 WL 4225030, at *5 (citation omitted).

Nonetheless, the dedications do not touch and concern Extraction's mineral estates because they concern only personal property and do not affect the physical use of real property or closely relate to real property. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 2.1, Ex. C ("Form of Tariff") at Item 5 (defining "Crude Petroleum" as "the direct liquid product of oil wells, or the indirect liquid petroleum products of oil or gas wells, or a mixture of such products"); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.1.

No party argues that the Transportation Agreements employed the conventional legal definition of a dedication, which would have meant that the parties intended the donation of Extraction's real property to the public use. *Stagecoach Prop. Owners Ass'n v. Young's Ranch*, 658 P.2d 1378, 1381 (Colo. App. 1982) ("[A] dedication has been defined as an appropriation of land by the owner of the fee to some public use and the adoption

thereof by the public."); Dedication, *Black's Law Dictionary* (11th ed. 2019) (defining "dedication" as "[t]he donation of land or creation of an easement for public use").

The plain and ordinary meaning of the word "dedicate" is "to set apart to a definite use." *Dedicate*, Merriam-Webster's Collegiate Dictionary 324 (11th ed. 2003).

The plain and ordinary meaning of "commit" is "to pledge . . . to some particular course or use." *Commit*, *id.*

Throughout the Transportation Agreements, the Interests are used to identify the particular minerals that are subject to, set apart for, pledged or committed to the parties' contractual obligations. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 1.1.(bb) (defining "Interests" as "all interests that [Extraction] . . . now or hereinafter owns, controls, acquires or has the right to market . . . in Crude Petroleum of all formations in, under or attributable to the Dedication Area . . . and all interests in any wells . . . on or completed within the Dedication Area"); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 1.1(dd) (defining "Interests" as all interests that [Extraction] . . . now or hereinafter owns, controls, acquires or has the right to market . . . in Crude Petroleum of all formations in, under or attributable to the Dedication Area, and all interests in any wells . . . on or completed within the Dedication Area"); *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 2.2(a) (reserving from the dedication "[a]ny Interest which is, at any time during the Term . . . operated by an operator other than Shipper"); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.2(a) (reserving from the dedication "[a]ny Interest which is, at any time during the Term . . . operated by an operator other than Shipper or . . . owned by a non-operator in a property operated by Shipper"); *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 2.2(b) (reserving from the dedication any

interest subject to a prior dedication); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.2(b) (reserving from the dedication any interest subject to a prior dedication).

Dedications, generally, only identify the particular produced minerals that are subject to, set apart for, pledged or committed to the parties' contractual obligations under the contracts for transportation services. *Cf. In re Sabine Oil & Gas Corp.*, 550 B.R. 59, 81 (Bankr. S.D.N.Y. 2016), *aff'd*, 567 B.R. 869 (S.D.N.Y. 2017), *aff'd*, 734 Fed. Appx. 64 (2d Cir. 2018) ("[The] 'dedication' [is not] a burdening of the Debtors' property interests, but rather an identification of what property and products are the subject of the Agreement and will be made available . . . in furtherance of the purposes of the Agreements."); *Moncrief v. Williston Basin Interstate Pipeline Co.*, 174 F.3d 1150, 1170 (10th Cir. 1999) (noting that dedication contracts are contracts "wherein the producer 'contracts to furnish the purchaser all the gas produced from specified reserves, thus dedicating those reserves to the customer'"); *Nordan-Lawton Oil & Gas Corp. of Tex. v. Miller*, 272 F. Supp. 125, 129 (W.D. La. 1967), *aff'd*, 403 F.2d 946 (5th Cir. 1968) ("In this contract the lessee 'dedicated' all the reserves under the Miller lease to the pipeline company which in essence means that the company was given exclusive rights to purchase the reserves under the premises when and if produced."); Latham & Watkins LLP, The Book of Jargon, Oil & Gas, The Latham & Watkins Glossary to Oil and Gas Terminology (1st ed. 2016) at 24 (defining a dedication as "a promise or commitment of a certain amount of Production from a Dedicated Area . . . to the services provider in a Midstream service agreement").

Produced minerals, such as crude petroleum, are personal property and not real property. *Smith v. El Paso Gold Mines, Inc.*, 720 P.2d 608, 609 (Colo. App. 1985) ("[A]t some

point after they are severed from the land, minerals lose their character as realty and 'become' personalty.").

The dedications do not limit Extraction's rights to the use or enjoyment of its mineral estates. *Extraction MSJ* (A. D.I. 5-1), Ex. A at §2.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.1. And the dedications do not increase the Defendants' rights (or convey to Defendants rights) respecting Extraction's mineral estates. *Extraction MSJ* (A. D.I. 5-1), Ex. A at §2.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 2.1.

Extraction retains exclusive control and possession of all minerals from severance from the ground through delivery into the pipeline systems. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 6.7 ("Shipper will be deemed to be in exclusive control and possession of the Crude Petroleum delivered by or for Shipper to the Pipeline System under this Agreement prior to and until such Crude Petroleum is delivered into the inlet flange of LACT units provided by Platte River for delivery into the Pipeline System . . . ."); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 7.7 (similar but respecting DJ South).

Extraction retains title to the crude petroleum throughout the entire transportation process, and the Defendants never obtain title to the crude petroleum at any point. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 6.7 ("Platte River shall be in control and possession of (although title will remain in Shipper or other person for whom Shipper has the right to transport Crude Petroleum) Crude Petroleum delivered by or for Shipper to the Pipeline System for shipment under this Agreement after delivery thereof into the Pipeline System . . . ."); *Extraction MSJ* (A. D.I. 5-2), Ex. B at §7.7 (similar but respecting DJ South).

Additionally, the contractual obligations and Services—the performance of which by Defendants this dedication and commitment was made—require the delivery of a certain volume of produced crude petroleum to the Defendants for the provision of transportation services from in exchange for a fee, or the payment of a certain amount of money. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 3.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 4.1.

The provision of such services does not affect the use or enjoyment of oil in place, or the use of the mineral estate, but crude petroleum that has been severed from the mineral estate and now constitutes the personal property of Extraction, as a merchant tin this commodity. As a result, the covenants contained in the Transportation Agreements do not benefit Extraction in its capacity as a landowner, but benefits and affects Extraction's use of its personal property (*i.e.*, its produced crude oil). *Cf.* Harry Bigelow, *The Content of Covenants in Leases*, 12 Mich. L. Rev. 639, 652 (1914).

Even assuming that the Transportation Agreements' dedications have an indirect effect upon Extraction's mineral estates, such as an incidental increase in value, this effect is not closely related to the land and, therefore, cannot satisfy touch and concern, as its primary affect is on the use and enjoyment of personal property, and not real property. *Reishus v. Bullmasters, LLC*, 409 P.3d 435, 440 (Colo. 2016) (noting "[a] covenant touches and concerns the land if it 'closely relate[s] to the land, its use, or enjoyment.'"); *cf.* Bigelow, *The Content of Covenants in Leases*, 12 Mich. L. Rev. 639, 652 (1914) (explaining that indirect effects are insufficient).

The "dedication" and "commitment" of real property interests to the performance of contractual obligations and services that closely relate to and affect only the use and enjoyment of personal property does not change this result. To hold otherwise would render the objective "touch and concern" element beholden to the subjective intent of the parties, and allow parties to convert covenants that do not closely relate to real property into covenants that bind successors and assigns simply by recitation of a set phrase.

Extraction's tender options confirm that the Transportation Agreements do not closely relate to Extraction's mineral estates. Extraction may fully perform under the Transportation Agreements without providing crude petroleum produced from its own mineral estates and may instead provide crude petroleum produced from the land of third parties. *Extraction MSJ* (A. D.I. 5-1), Ex. A § 3.1 (reciting Extraction's agreement to tender "for transportation, or otherwise to pay for the transportation of, the Committed Volume in accordance with the tender procedures set forth in the Tariff and the terms of this Agreement . . . .") ; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 4.1 (same).

Extraction's payment options similarly confirm that the Transportation Agreements' covenants do not closely relate to Extraction's real property. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 3.1; *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 4.1.

Extraction could satisfy its obligations under the Transportation Agreements by either (1) shipping certain amounts of crude petroleum or (2) payment of the Total Financial Commitment. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 3.1 ("Shipper's obligation to ship or pay its Committed Volume under this Agreement shall be satisfied in full upon

the earlier" of shipment of a certain volume of crude petroleum or payment of the Total Financial Commitment); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 4.1 (same).

Payment of the Total Financial Commitment is purely the payment of a specified amount of money set forth in the Transportation Agreements. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 6.2 ("For the avoidance of doubt, the Total Financial Commitment will be satisfied by payment by Shipper of the aggregate of the Fixed Monthly Payments in accordance with the terms of this Agreement, or at Shipper's option, any payment made by Shipper to accelerate the satisfaction of that obligation."); *Extraction MSJ* (A. D.I. 5-2), Ex. B at § 7.2 (same).

Moreover, Extraction may accelerate the satisfaction of the Total Financial Commitment, and its obligations under the Transportation Agreement, through payment. *Extraction MSJ* (A. D.I. 5-1), Ex. A at § 6.2 ("For the avoidance of doubt, the Total Financial Commitment will be satisfied by payment by [Extraction] of the aggregate of the Fixed Monthly Payments in accordance with the terms of this Agreement, or at [Extraction's] option, any payment made by [Extraction] to accelerate the satisfaction of that obligation."); Ex. B at § 7.2 (same).

The payment of money is a personal commitment that does not touch and concern Extraction's mineral estates. *Bigelow v. Nottingham*, 833 P.2d 764, 767 (Colo. App. 1991), *rev'd in part sub nom. on other grounds Haberl v. Bigelow*, 855 P.2d 1368 (Colo. 1993) (holding that a subordination agreement was a personal covenant that did not run with the land because "the parties' entitlement to physical use of the land was not increased, nor was improvement made to the land as a result of subsequent loan proceeds").

The dedications contained in the Transportation Agreements do not closely relate to, or affect, the use or enjoyment of Extraction's mineral estates. As a result, they do not touch and concern Extraction's mineral estates, and do not create covenants that run with the land.

III. Privity of Estate.

The Court is bound to apply Colorado law as declared by the Colorado Supreme Court until the Colorado Supreme Court disturbs its prior holdings. *Erie County v. Am. States Ins. Co.*, 573 F. Supp. 479, 486 (W.D. Pa. 1983) ("While plaintiff questions the continuing vitality of *Gordon,* we are bound to consider the [Pennsylvania] Supreme Court's undisturbed holding in *Gordon* as good law on this point."), *aff'd*, 745 F.2d 45 (3d Cir. 1984*) and aff'd sub nom. Am. States Ins. Co. v. Santafemia*, 745 F.2d 45 (3d Cir. 1984); *cf. Bosse v. Oklahoma*, 137 S. Ct. 1, 2 (2016) ("Our decisions remain binding precedent until we see fit to reconsider them, regardless of whether subsequent cases have raised doubts about their continuing vitality.").

The Colorado Supreme Court requires privity of estate between the covenanting parties at the time of the covenant's creation before the covenant may run with the land. *Taylor v. Melton*, 274 P.2d 977, 988–89 (Colo. 1954) (noting "the requisite privity exists in the case of a covenant by a grantor to do or not to do something on land retained by him, adjoining that conveyed, so that one to whom the former is subsequently conveyed by him may be bound by the covenant"); *Farmers' High Line Canal & Reservoir Co. v. New Hampshire Real Estate Co.*, 92 P. 290, 293 (Colo. 1907) ("[W]here there is the requisite privity of estate, and the covenant is connected with or concerns the land or estate conveyed,

then a covenant imposing a burden will run with the land as readily as one conferring a benefit."); *Hottell v. Farmers' Protective Ass'n*, 53 P. 327, 330 (Colo. 1898) (concluding a covenant running with the land was created, in part, because privity of estate was not denied).

Colorado appellate courts confirm that Colorado law requires this privity of estate. *Fed. Deposit Ins. Corp. v. Mars*, 821 P.2d 826, 829 (Colo. App. 1991) ("For contractual obligations between a lessor and lessee to pass to a successor in title of the lessee, there must be either privity of contract or privity of estate between the lessor and that successor in title."); *Fisk v. Cathcart*, 33 P. 1004, 1005 (Colo. App. 1893) ("Under these circumstances, there is no privity between him as a grantee from Beecher and the prior grantors subsequent to Parker which entitles him to maintain his suit upon his covenant.").

Colorado statutory law identifies several covenants that necessarily run with the land, provided that those covenants satisfy privity of estate between the covenanting parties. Colo. Rev. Stat. § 38-30-121 ("Covenants of seisin, peaceable possession, freedom from encumbrances, and warranty contained in any conveyance of real estate, or any interest therein, shall run with the premises and inure to the benefit of all subsequent purchasers and encumbrancers.").

Real property treatises continue to cite Colorado Supreme Court cases for the proposition that privity of estate between the covenanting parties is required. 3 Tiffany Real Property § 851 n. 27 (3d ed. 2015) (citing *Taylor* for the proposition that privity of estate at the time of the creation of the covenant is required); *see also* 9 Richard R. Powell,

Powell on Real Property § 60.04 n. 123 (citing *Farmers' High Line* for the proposition that either mutual or horizontal privity are required for a covenant to run with the land).

Defendants argue that no Colorado court has referenced the concept of privity of estate or horizontal privity since 1954. Indeed, they argue, the year after *Taylor* was decided, the Colorado Supreme Court held a restrictive covenant ran with the land, even though it was never in the defendant's chain of title, and that it could be enforced even between parties that had no direct contractual relations. *See Pagel v. Gisi*, 286 P.2d 636, 638-39 (Colo. 1955). Privity was unnecessary to create the covenant then, and it is unnecessary now. *See id*.

Defendants further argue that every subsequent Colorado decision regarding covenants running with the land—including the cases cited by Extraction—has expressly stated the only requirements to create a real covenant are (1) the parties' intent, and (2) the covenant touches and concerns the land. *See*, *e.g.*, *Reishus v. Bullmaters, LLC*, 409 P.3d 435, 440 (Colo. App. 2106) (containing no reference to horizontal privity requirement); *DeJean v. Grosz*, 412 P.3d 733, 739 (Colo. App. 2015) (same); *In re Banning Lewis Ranch Co.*, 532 B.R. 335, 345 n.11 (Bankr. D. Co. 2015) (same); *MidCities Metro. Dist. No. 1. v. U.S. Bank Nat'l Ass'n*, Civil No. 12-cv-03322, 2013 WL 3200088, at *3 (D. Colo. June 24, 2013) (same); *Lookout Mountain Paradise Hills Homeowners' Ass'n v. Viewpoint Assocs.*, 867 P.2d 70, 74 Col. App. 1993) (same); *Cloud v. Association of Owners*, 857 P.2d 435, 440 (Colo. App. 1992) (same); *Bigelow v. Nottingham*, 833 P.2d 764, 767-68 (Colo. App. 1991), *rev'd in part sub nom. on other grounds Haberl v. Bigelow*, 855, P.2d 1368 (Colo. 1993)(same). The Fifth Circuit reached the same conclusion after conducting a "survey of Colorado case law." *TBI Expl.*,

No. 99-10872, 2000 WL 960047, at *4 (5th Cir. June 14, 2000) (only elements required under Colorado law are "intent by the parties to the covenant that the covenant runs with the land" and "the covenant must 'touch and concern' the land.") (collecting cases).

Nonetheless, the Defendants have not identified a single case from the *Colorado Supreme Court holding that Colorado law no longer requires privity of estate* between the original covenanting parties to create a covenant running with the land. *Platte River Response* (A. D.I. 21).

The Restatement (Third) of Property does not restate Colorado law regarding covenants that run with the land, and Colorado has not adopted the reforms suggested therein. *See* Restatement (Third) of Property Servitudes § 3.2 (Am. Law Inst. 2000) (dispensing with the acknowledged touch and concern requirement and stating "[n]either the burden nor the benefit of a covenant is required to touch or concern land in order for the covenant to be valid as a servitude.")

Privity of estate requires that the covenants that allegedly run with the land be accompanied by a contemporaneous conveyance of some interest in the land with which the covenant runs. *Taylor v. Melton*, 274 P.2d 977, 988–89 (Colo. 1954) (noting "the requisite privity exists in the case of a covenant by a grantor to do or not to do something on land retained by him, adjoining that conveyed, so that one to whom the former is subsequently conveyed by him may be bound by the covenant"); 9 Richard R. Powell, Powell on Real Property § 60.04(3)(c)(iii) ("'Horizontal privity' typically exists when the original covenanting parties make their covenant in connection with the conveyance of an estate in fee from one of the parties to the other. The covenant and the conveyance

must be made at the same time . . . ."); 3 Tiffany Real Property § 851 (3d ed. 2015) (describing "privity of estate between the covenantor and the covenantee at the time the covenant was created").

The Transportation Agreements do not convey to the Defendants any real property interest in Extraction's mineral estate. *Extraction MSJ* (A. D.I. 5-1), Ex. A; *Extraction MSJ* (A. D.I. 5-2), Ex. B.

The Defendants failed to identify any real property interest in Extraction's mineral estate that was purportedly conveyed contemporaneously with the alleged covenant running with the land, choosing instead to argue that privity of estate was not required. *Platte River Response* (A. D.I. 21).

The surface estate and mineral estate, once severed, are separate and distinct estates in real property. *Notch Mountain Corp. v. Elliott*, 898 P.2d 550, 556 (Colo. 1995) ("[Colorado has] long recognized that a conveyance which severs a mineral interest from the surface estate creates a separate and distinct estate."); *Gerrity Oil & Gas Corp. v. Magness*, 946 P.2d 913, 927 (Colo. 1997), *as modified on denial of reh'g* (Oct. 20, 1997) ("As the owner of property subject to the easement, the surface owner 'continues to enjoy all the rights and benefits of proprietorship *consistent with the burden of the easement*.'").

The Defendants point to the following as interests sufficient to satisfy Colorado's privity of estate requirement: (1) an above-ground pipeline transportation system conveyed by XTR Midstream, a non-party to the Transportation Agreements; (2) equity interests through an LLC agreement acquired by non-parties to the Transportation Agreements; (3) purported easements or rights-of-way on Extraction's surface estate; and

(4) the Transportation Agreements' dedications. *Platte River Response* (A. D.I. 21) at ¶¶ 95 and 98. As a matter of law, these alleged interests cannot satisfy Colorado's privity of estate requirement to create a covenant running with the land.

First, an equity interest in the pipeline transportation system is not a real property interest in Extraction's mineral estate. To satisfy Colorado law's requirement for privity of estate between the covenanting parties, the interest must be conveyed between the covenanting parties and it must be an interest in the mineral estate (the estate in real property with which the covenant is intended to run). *Taylor v. Melton*, 274 P.2d 977, 988–89 (Colo. 1954) (requiring privity of estate between the covenanting parties).

The conveyance here was with a non-party to the relevant covenant and not Extraction. *Platte River Response* (A. D.I. 21-6), Ex. F (Extraction not a party to the contract).

An equity interest in the pipeline is not an interest in Extraction's oil in place.

Further, the pipeline is not an interest in the mineral estate. *Notch Mountain Corp. v. Elliott*, 898 P.2d 550, 556 (Colo. 1995) ("[Colorado has] long recognized that a conveyance which severs a mineral interest from the surface estate creates a separate and distinct estate.")

Second, the sale of a subsidiary is not a sale of an interest in the mineral estate. Nor is an equity interest in a company an interest in real property. *See* Property, *Black's Law Dictionary* (11th ed. 2019) (defining "real property" as "[l]and and anything growing on, attached to, or erected on it, excluding anything that may be severed without injury to the land").

Third, any purported easements or rights-of-way on Extraction's surface estate fail to satisfy privity of estate for several reasons. As an initial matter, all of the easements or rights-of-way at issue here are either between parties that are not the covenanting parties or they were conveyed long after the dedication was executed. *Platte River Response* (A. D.I. 21), Ex. G (A. D.I. 21-7) (Extraction not a party to the contract); Ex. H (A. D.I. 21-8) (same); Ex. N (A. D.I. 21-14) (same); Ex. S (A. D.I. 21-19) (same); Ex. L (A. D.I. 21-12) (right-of-way granted to Platte River on July 17, 2019).

The conveyance needed to satisfy privity of estate must be made between the covenanting parties and contemporaneously with the creation of the covenant running with the land. 3 Tiffany Real Property § 851 (3d ed. 2015) (cited approvingly by the Colorado Supreme Court to describe the requirements of privity of estate in *Taylor v. Melton*, 274 P.2d 977, 982 (Colo. 1954). A stranger to the covenant cannot grant or receive a real property interest that establishes privity of estate between the contracting parties. *Id*. at 982–83 (requiring privity of estate between the covenanting parties); *Farmers' High Line Canal & Reservoir Co. v. New Hampshire Real Estate Co.*, 92 P. 290, 293 (Colo. 1907) (same).

The single conveyance of rights-of-way from Extraction to Platte River occurred on July 17, 2019. *Platte River Response* (A. D.I. 21-12), Ex. L at p. 1. The parties, however, entered the Platte River Contract two years prior, on May 14, 2017. Consequently, the right-of-way grant cannot satisfy privity of estate, which requires the grant of a real property interest ***contemporaneous*** with the creation of the covenant intended to run. 3

Tiffany Real Property § 851 (3d ed. 2015) (cited approvingly by the Colorado Supreme Court to describe the requirements of privity of estate in *Taylor*, 274 P.2d at 982.

Next, an interest in the surface estate cannot qualify as a conveyance as an interest in Extraction's mineral estate as a matter of Colorado law. Conveyances of easements or rights-of-way across the surface estate are interests in the surface estate that cannot satisfy privity of estate respecting a mineral estate. *Notch Mountain Corp. v. Elliott*, 898 P.2d 550, 556 (Colo. 1995) (noting Colorado has "long recognized that a conveyance which severs a mineral interest from the surface estate creates a separate and distinct estate").

Because easements in gross are personal rights in the use of (and interests in) the surface estate, they are not interests in a severed mineral estate. *Lobato v. Taylor*, 71 P.3d 938, 945 (Colo. 2002) ("An easement in gross does not belong to an individual by virtue of her ownership of land, but rather is a personal right to use another's property."). As a result, the conveyance of an easement in gross in a surface estate cannot satisfy privity of estate respecting a mineral estate.

The Defendants also implied that Extraction conveyed easements or rights-of-way associated with the mineral estate. *Elevation Response* (A. D.I. 21) at ¶ 96.

However, Extraction expressly cannot convey any property interest it lacked the ability to convey.

Extraction lacked the ability to convey any easement appurtenant separate and apart from the land the easement is annexed to (here, Extraction's mineral estates). *Lewitz v. Porath Family Tr.*, 36 P.3d 120, 122 (Colo. App. 2001), as modified on denial of reh'g (Apr. 26, 2001) ("[A]n easement appurtenant is an 'incorporeal right' attached to

and belonging with some other parcel of land. It runs with that land and is incapable of existence separate and apart from the particular land to which it is annexed.").

Extraction also lacked the ability to convey its rights of ingress and egress upon the surface estates, which are incidental (and appurtenant) to ownership of Extraction's mineral estates. *Gerrity Oil & Gas Corp. v. Magness*, 946 P.2d 913, 926 (Colo. 1997), as modified on denial of reh'g (Oct. 20, 1997) ("In this sense, the right of access to the mineral estate is in the nature of an implied easement, since it entitles the holder to a limited right to use the land in order to reach and extract the minerals."); *Chase v. Colorado Oil & Gas Conservation Comm'n*, 284 P.3d 161, 171 n. 17 (Colo. App. 2012), as modified on denial of reh'g (July 19, 2012) ("Mineral estate owners have an implied easement, which burdens the surface interest and empowers mineral owners to make reasonable use of the surface in order to access the minerals below."); *Entek GRB, LLC v. Stull Ranches, LLC*, 885 F. Supp. 2d 1082, 1088 (D. Colo. 2012) ("Because the mineral estate is considered the dominant estate, it impliedly carries with it a right to use as much of the surface as may be reasonably necessary for operations relating to the mineral estate.").

Rights of ingress and egress are not real property interests capable of satisfying privity of estate; they are incidental rights. *Smith v. Moore*, 474 P.2d 794 (Colo. 1970) ("Though the privilege to use the surface is recognized at law, this right does not create an ownership interest in the surface estate . . . but merely a right of access.").

Fourth, and finally, the dedication itself is not a conveyance in real property. The dedication cannot be both the real covenant and the element that satisfies privity of estate to create a real covenant. Dedications are not conveyances of real property interests

capable of satisfying privity of estate. *Stagecoach Prop. Owners Ass'n v. Young's Ranch*, 658 P.2d 1378, 1381 (Colo. App. 1982) ("This regulation clearly contemplates a 'conveyance' and not a 'dedication' which terms are not synonymous.").

Dedications only identify the particular produced crude petroleum within a particular area that is subject to the parties' contractual obligations. *In re Sabine Oil & Gas Corp.*, 547 B.R. 66, 76 (Bankr. S.D.N.Y. 2016), *aff'd*, 567 B.R. 869 (S.D.N.Y. 2017), *aff'd*, 734 Fed. Appx. 64 (2d Cir. 2018).

Accordingly, the original covenanting parties to the Transportation Agreements were not in privity of estate at the time of the creation of the covenants therein, and the Transportation Agreements contain no covenants that run with the land. *Taylor v. Melton*, 274 P.2d 977, 988–89 (Colo. 1954) (requiring privity of estate between the covenanting parties).

CONCLUSION

As set forth above, the Transportation Agreements are unambiguous and the question of whether the Transportation Agreements contain any covenants that run with the land is a legal one. There is no genuine issue of material fact. Extraction has met its burden for entry of summary judgment against Defendants based on the plain meaning of the Transportation Agreements. As to Platte River, there was no intent by the parties to create a covenant that runs with the land; the Platte River Contract does not touch and concern the land; and there is no privity among the parties. As to DJ South, the parties intended the dedication and commitment in section 2.5 of the DJ South Contract to be a covenant that runs with the land (the parties did not intend that any other provision of

the contract to create a covenant that runs with the land); the DJ South Contract does not touch and concern the land; and there was no privity among the parties. Thus, as not all the required elements are present in either contract, the Court will enter summary judgment in favor of Extraction. An Order and Judgment will be entered.

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By the Court:

Christopher S. Sontchi
Chief United States Bankruptcy Judge

Date: October 14, 2020

EXHIBIT H

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

IN RE:	)	Chapter 11
	)	Case No. 20-11548 (CSS)
EXTRACTION OIL & GAS, *et al.*	)	
	)	
	)	Related Docket Nos.: 14, 363,
Debtors.	)	412, 482, 655, 681, 801, and 803
	)	

BENCH RULING

Before the Court is a series of motions and notices to reject unexpired leases of nonresidential real property and executory contracts (*see* D.I. 14 and 412, collectively, the "Motions") as well as objections from Grand Mesa Pipeline, LLC (D.I. 363 and 803, referred to as "Grand Mesa"); and Platte River Midstream, LLC, DJ South Gathering, LLC, and Platte River Holdings, LLC (D.I. 482, 655 and 801, collectively referred to as "Platte River" and with Grand Mesa, the "Rejection Counterparties") and the contracts the Debtors seek to reject, collectively, the "Transportation Services Agreements" or "TSAs").[1] The Court held evidentiary hearings on the rejection motions on October 7, 20, 26, and 27, and, on October 28, the Court heard closing arguments.[2]

[1] The TSAs at issue in the Motions are: (i) **Grand Mesa TSAs:** (a) Amended and Restated Transportation Agreement dated June 21, 2016 (the "Bayswater Contract"), Debtors' Ex. 32; (b) Amended and Restated Transportation Services Agreement dated February 19, 2016 (the "Grand Mesa Contract" and together with the Bayswater Contract, the "Grand Mesa TSAs"), Debtors' Ex. 33; and (ii) **Platte River TSAs:** (a) First Amended and Restated Transportation Services Agreement dated April 14, 2017 (the "Platte River Contract"), Debtors' Ex. 24; (b) Transportation Services Agreement dated May 16, 2018 (the "DJ South Contract" and together with the Platte River Contracts, the "Platte River TSAs"), Debtors' Ex. 26.

[2] The Transcripts are docketed as D.I. 812, 877, 926, and 933. Citations to the hearing transcripts will be noted as Date Hr'g Tr. page:line.

JURISIDICTION

The United States Bankruptcy Court for the District of Delaware (the "Court") has jurisdiction over this matter, pursuant to 28 U.S.C. §§ 157 and 1334. Venue is proper, pursuant to 28 U.S.C. §§ 1408 and 1409. The bases for the relief requested are sections 105(a), 363(b), and 365(a) of the Bankruptcy Code, Bankruptcy Rules 6004, 6006, and 6007, and Bankruptcy Local Rule 9013-1.

BACKGROUND

Extraction Oil & Gas and certain of its affiliates (the "Debtors") filed their petitions under Chapter 11 of the Bankruptcy Code on June 14, 2020. The Debtors cases are jointly administered for procedural purposes.[3] The Debtors operate primarily in the "upstream" oil and gas sector, including the exploration and production of oil and gas. The oil and gas industry can be broken up into three segments: (i) upstream, (ii) midstream, and (iii) downstream. Upstream activities are mainly "Exploration and Production" or E&P activities that focus on locating and extracting hydrocarbons from beneath the surface. Common upstream assets include mineral leases, producing wells, and associated production equipment. The midstream sector includes the activities involved in gathering, transporting, processing, and storing hydrocarbons. Common midstream assets include gathering pipelines, separation facilities, and tankage. The downstream sector is focused on the marketing and distribution of the products derived from the

[3] D.I. 79.

extracted hydrocarbons to the ultimate end users. Common downstream assets include refineries and retail sites.

The majority of the Debtors' assets are in the upstream sector, but the Debtors also have limited ownership in midstream assets. Prior to bankruptcy, the Debtors contracted with midstream counterparties, including the Rejection Counterparties, to transport their oil and gas from the production points to downstream providers. These TSAs are not only agreed to between and among the parties, but the rates are approved by the Federal Energy Regulatory Commission ("FERC"). The Debtors filed the Motions seeking authorization to reject these TSAs, which are contested by the Rejection Counterparties. This is the Court's ruling on the rejection of the TSAs.

ANALYSIS

A. Rejection of Leases and Executory Contracts

Section 365(a) of the Bankruptcy Code provides that a debtor in possession "may assume or reject any executory contract or unexpired lease of the debtor" subject to the court's approval. Courts generally authorize debtors to assume or to reject executory contracts and unexpired leases where the debtors appropriately exercise their "business judgment."[4] "An executory contract is a contract under which the obligation of both the

[4] *See, e.g., Sharon Steel Corp. v. Nat'l Fuel Gas Distrib. Corp.*, 872 F.2d 36, 39–40 (3d Cir. 1989); *In re Fed. Mogul Global, Inc.*, 293 B.R. 124, 126 (D. Del. 2003); *Orion Pictures Corp. v. Showtime Networks, Inc. (In re Orion Pictures Corp.)*, 4 F.3d 1095, 1099 (2d Cir. 1993); *Robertson v. Pierce (In re Chi-Feng Huang)*, 23 B.R. 798, 800 (B.A.P. 9th Cir. 1982); *Lubrizol Enters. v. Richmond Metal Finishers, Inc. (In re Richmond Metal Finishers, Inc.)*, 756 F.2d 1043, 1047 (4th Cir. 1985) (holding that absent bad faith or abuse of discretion, deference is given to debtor's business judgment); *Wheeling-Pittsburgh Steel Corp. v. West Penn Power Co. (In re Wheeling-Pittsburgh Steel Corp.)*, 72 B.R. 845, 849 (Bankr. W.D. Pa. 1987); *In re G Survivor Corp.*, 171 B.R. 755, 757 (Bankr. S.D.N.Y. 1994).

bankrupt and the other party to the contract are so far underperformed that the failure of either to complete performance would constitute a material breach excusing the performance of the other."[5]

Importantly, "although Congress knew how to craft exceptions to rejection, Congress declined to except FERC approved contracts."[6] There is no prohibition on or limitation against rejecting a FERC approved contract. Therefore, the Court was tasked with determining whether (i) the Debtors' decision to reject was a proper exercise of business judgment, (ii) public policy prohibits the rejection of such contracts; and (iii) the matter should be referred to FERC.

B. Business Judgment

The "business judgment" test requires a showing that rejection of the executory contract or unexpired lease will benefit the debtor's estate.[7] Courts generally will not second-guess a debtor's business judgment concerning the rejection of an executory contract or unexpired lease.[8] The "business judgment" test merely requires a showing that rejection will benefit the debtor's estate. "A debtor's decision to reject an executory

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[5] *In re Exide Techs.*, 607 F.3d 957, 967 (3d Cir. 2010), as amended (June 24, 2010) (*quoting In re Columbia Gas Sys. Inc.*, 50 F.3d 233, 239 (3d Cir. 1995)). *See also Mission Prod. Holdings, Inc. v. Tempnology, LLC*, 139 S. Ct. 1652, 1667 (2019) (Section 365 "enables a debtor to 'reject any executory contract'—meaning a contract that neither party has finished performing.").

[6] *In re Ultra Petroleum Corp.*, No. 20-32631, 2020 WL 4940240, at *6 (Bankr. S.D. Tex. Aug. 21, 2020). *See, e.g.*, 11 U.S.C. §§ 365(n)(intellectual property rights), 365(h)&(i) (real property leases and time share interests).

[7] *In re Trans World Airlines*, 261 B.R. 103, 121 (Bankr. D. Del. 2003). ("A debtor's decision to reject an executory contract must be summarily affirmed unless it is the product of 'bad faith, or whim or caprice'") (*quoting In re Wheeling-Pittsburgh Steel Corp.*, 72 B.R. at 849–50); *In re Trans World Airlines, Inc.*, No. 01-0056, 2001 Bankr. LEXIS 722, at *7–8 (Bankr. D. Del. Mar. 16, 2001) (noting that 5 the standard under section 365 requires consideration of the benefit of the rejection to the debtor's estate).

[8] *See Trans World Airlines*, 261 B.R. at 121.

contract must be summarily affirmed unless it is the product of '**bad faith, or whim or caprice**.'"[9] Importantly, the Court cannot substitute its judgment for the Debtors' judgment[10] and absent a heightened standard such as bad faith or abuse of discretion the Debtors' business judgment will be not altered.[11]

The Debtors assert that the TSAs are neither compatible with the Debtors' ongoing business needs nor a source of potential value for the Debtors' future operations, creditors, or other parties in interest. Absent rejection, the TSAs impose ongoing obligations on the Debtors and their estates that constitute an unnecessary drain on the Debtors' resources. Here, the Debtors presented evidence of the following: (i) Debtors' estate will benefit from rejection of the TSAs because the Grand Mesa, Bayswater, and Platte River Contracts charge rates significantly above market rates, the estate will save millions of dollars annually if allowed to reject these contracts; and (ii) Rejecting the DJ South Contract is in the Debtors' interest because the Debtors would be able to use an alternative service provider that, unlike DJ South, will take their crude oil to Platteville, a location where the Debtors can sell their crude oil for a significantly higher price.

The Rejecting Counterparties presented evidence but did not rebut the Debtors' business judgment. In fact, testimony reflected that the Debtors may also use a "walk-

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[9] *Id.* (emphasis added).

[10] *In re Prime Motor Inns*, 124 B.R. 378, 381 (Bankr. S.D. Fla. 1991).

[11] *In re Old Carco LLC*, 406 B.R. 180, 188 (Bankr. S.D.NY. 2009) ("Moreover, the business judgment standard . . . requires that the decision be accepted by courts unless it is shown that the bankrupt's decision was taken in bad faith or in gross abuse of the bankruptcy retained business discretion."). *See also Federal Mogul Global, Inc.*, 293 B.R. at 126 ("The business judgment test dictates that a court should approve a debtor's decision to reject a contract unless that decision is the product of bad faith or a gross abuse of discretion.").

up" rate with some of the midstream pipeline providers.[12] Additionally, the Debtors presented evidence of ability to use trucks as alternatives to using the pipelines. Furthermore, the Debtors can shut-in wells (or partially shut-in wells) until alternative shipment methods become available.

The Debtors presented evidence that the alternative transportation would cost less and that a new midstream pipeline may transport the oil to a more favorable location in some instances. With the current contract rates at higher-than-market value for transporting the Debtors' oil, it is within the Debtors' business judgment to reject these contracts and to seek alternative providers, whether by walk-up rates, trucking, or new pipeline contracts.

More specifically, the Debtors presented the testimony of its Chief Executive Officer Matthew Owens. Mr. Owens, despite his youth, is one of the most competent, well informed, measured, and persuasive executives that has ever testified before me. He made a solid case in favor of the Debtors' business judgment. Mr. Owens testified that rejection enables the Debtors to access the pipeline providers at a more competitive Platteville terminal[13] and that such access will save the company tens of millions of dollars per year.[14] Mr. Owens continued that without the onerous rates and deficiency

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[12] The Court finds the statements of certain of the Rejecting Counterparties that, in a fit of pique, they will not accept the Debtors as a walk-up shipper not to be credible.

[13] Oct. 7, 2020 Hr'g Tr. 79:10-15 (Access to the Platteville terminal "is extremely important for the company because the three other pipelines that perform the same service as Grand Mesa are located in Platteville; therefore, for the company to access a competitive market, we need to have access to Platteville. Instead, we're stuck in Lucerne and stuck with one person who can set the price.").

[14] Oct. 7, 2020 Hr'g Tr. 80:22-24 ("[I]f we were to access Platteville . . . we estimate that the company could increase its margins in 2021 by anywhere from $25 to $32 million dollars [if it could access Platteville].").

claims, rejection of the DJ South Contract would save the Debtors between $4.5 and $5.5 million in 2021.[15] Furthermore, Mr. Owens testified that, as to Platte River, reasonable alternatives could be up-and-running within 90 days[16] because the alternative infrastructure was already within a mile of the well (versus constructing a whole new pipeline that was 90-miles from the well).[17] Rogan McGillis, ARB Midstream's Chief Financial Officer, who was a competent and well-prepared witness but whose testimony was self-serving and, ultimately, unpersuasive, could not rebut the timing or feasibility of the Debtors' alternatives to the Platte River gathering system.

Mr. Owens also testified about the DJ South pipeline. He stated that alternative pipeline providers will be able to install the short connections between their existing infrastructure and the collection points in the DJ South dedication area in a matter of months – again, the testimony reflects that the alternative pipeline providers are relatively close to the Debtors' wells.[18] Again, Mr. McGillis could not rebut the timing or feasibility of the Debtors' alternatives to the DJ South gathering systems.

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[15] *Compare* Debtors Ex. 42 to Debtors Ex. 57.

[16] Oct. 7, 2020 Hr'g Tr. 87:11-24 ("[The timeline for alternative pipeline companies] varies pad by pad. . . . [W]e had some pads that are already connected to oil gathering companies. . . . We have other pads where . . . it would only require building a couple hundred feet of flow line connections and we think that would be done in a month timeframe or less. And then a few of the other pads that are further away, they gave us a schedule of . . . three to six months to obtain the necessary rights-of-way. . . . In most cases, for the alternate pad that they would be connecting, it's anywhere from a half mile to a mile and a half connection, so not very long.").

[17] Oct. 7, 2020 Hr'g Tr. 88:3-13 ("[F]or Platte River to construct its entire gathering system it took . . . eighteen months or so because they were building around ninety miles of pipe . . . [T]he third-party company we received a proposal from . . . has already constructed the backbone of their pipeline systems. And all they need to do are build small connectors to connect us into the backbone of that system.").

[18] Oct. 7, 2020 Hr'g Tr. 102:8-18 ("[T]he alternatives [to DJ South] are very close to the Badger central gathering facility . . . they only need to connect to one point. They only need to connect to that central gathering facility. They do not need to connect to multiple well pads like the alternative to Platte River

As to Platte River and DJ South, Mr. Owens also testified about the economic benefit of rejection[19] of the TSAs and the realistic alternatives.[20] Mr. Owens provided details about the cost of alternatives[21] and the timeframe to alternative transition.[22] Mr. Owens continued regarding the Debtors' analysis of the regulatory requirements to

would have to do. So the fact that they only need to build out to one point that is roughly . . . one to one and a half miles away, we believe in our talks with them that it could be as little as ninety days to as much as 180 days to finish that connection."); Oct. 7, 2020 Hr'g Tr. 102:21-103:4 ("You can't really compare [the time to construct the DJ South system to the time to construct an alternative] because for DJ South they were building a large system which I believe is probably 50 miles or so in length, so it took them a long time to do that, where these companies that have submitted bids to us have already built out their pipeline systems to Platteville, so all they need to do is connect into their existing infrastructure which, as I mentioned, is very close to the Badger central gathering facility.").

[19] Oct. 7, 2020 Hr'g Tr. 80:22-24 (Platte River Contract: "[W]e estimate that the company could increase its margins in 2021 by anywhere from $25 to $32 million dollars" if it had access to the Platteville terminal); Oct. 7, 2020 Hr'g Tr. 102:1-3 (DJ South Contract: "[T]he total savings based on the bids that we have received would be anywhere from $4.5 to $5.5 million dollars in calendar year 2021.").

[20] Oct. 7, 2020 Hr'g Tr. 86:6-13 (Platte River Contract: "[W]e reached out to multiple trucking companies to solicit bids, as well as alternate oil gathering companies that perform the same services as Platte River. And we solicited bids from them, as well as timing for when they thought they could transport the crude from the pads that we laid out, and that is how we used or that is how we came up with the timing of this oil being pivoted off of the Platte River system."); Oct. 7, 2020 Hr'g Tr. 100:21-101:2 (DJ South Contract: "[Extraction] have gone out to multiple other oil gathering companies who have pipeline very close within about a mile to a mile and a half or so of the Badger central gathering facility. And we have received bids from them to connect their oil pipeline to the Badger central gathering facility and transport the oil from the Badger central gathering facility to the Platteville Terminal.").

[21] Oct. 7, 2020 Hr'g Tr. 80:7-15 (Platte River Contract: "[Extraction] have gone out and done marketing analysis and received proposals from companies who could ship our oil from Platteville . . . the cost that we have received from the pipelines in Platteville to transport our oils to the same place in Cushing, Oklahoma is $1.60 to $2.20 per barrel."); Oct. 7, 2020 Hr'g Tr. 101:22-102:1 (DJ South Contract: "The alternatives that we received are . . . at sixty cents to $1.00 per barrel and we would anticipate the gross spend associated with these contracts that we've been offered to be $1.5 to $2.5 million dollars.").

[22] Oct. 7, 2020 Hr'g Tr. 87:11-24. (Platte River Contract: "[The timeline for alternative pipeline companies] varies pad by pad. . . . [W]e had some pads that are already connected to oil gathering companies. . . . We have other pads where . . . it would only require building a couple hundred feet of flow line connections and we think that would be done in a month timeframe or less. And then a few of the other pads that are further away, they gave us a schedule of . . . three to six months to obtain the necessary rights-of-way. . . . In most cases, for the alternate pad that they would be connecting, it's anywhere from a half mile to a mile and a half connection, so not very long."); Oct. 7, 2020 Hr'g Tr. 102:16-18 (DJ South Contract: "[W]e believe in our talks with [alternative providers] that it could be as little as ninety days to as much as 180 days to finish that connection [to the Badger central gathering facility].").

transition to another pipeline provider,[23] including interim options, such as shutting-in, trucking, and/or walk-up shipping.[24] Mr. Owens described the best and worst-case scenarios for making the transition to new pipeline suppliers.[25]

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[23] Oct. 7, 2020 Hr'g Tr. 88:18-25 ("[The alternative providers' need to obtain permits and rights-of-way] was submitted to us in their bid, so we gave them the location of our pads and they looked at the distance from their current infrastructure to the pads that we would like to have connected, and they analyzed quickly the routes that they would probably most likely take to get there. And in their bid, they provided what they thought the timing would be, so that was assumed in that three to six-month timeframe that we've talked about with the alternative providers.").

[24] Oct. 7, 2020 Hr'g Tr. 89:15-90:3 (Platte River Contract: "[T]he majority of our pads we would be able to start trucking in very short order so those would not have any significant down times. But we have spent a lot of time thinking about what we would do during that several month period for the few pads that would currently require a new pipeline in order to continue producing. Our alternative there would be set those pads up for trucking, get a modification temporarily for permits to allow trucking or we could continue to ship on the Platte River system as a walk-up shipper. But, in the worst case, we would shut in those wells for a short period of time until the new company is connected, and then we would quickly make up that deferred oil production that was not produced during the short shut in period.); Oct. 7, 2020 Hr'g Tr. 103:9-23 (DJ South Contract: "We are unable to truck any oil from the central gathering facility, so we would have to shut-in the wells, at least two of the three pads that produce to the central gathering facility, while we wait for a third-party line to be built or we have the option to produce temporarily as a walk-up shipper under the DJ South tariff filed with FERC. […] We believe [walk up shipping is] a viable alternative because it's explicitly allowed under the FERC tariff and I don't believe can be turned away. But also, Extraction is one of the largest shippers on the DJ South system, and I don't believe that they would willingly forego a large amount of revenue for several months just to prevent us from walk-up shipping."); Oct. 7, 2020 Hr'g Tr. 94:7-16 (Shutting in wells: "The oil isn't necessarily lost during the shut-in period. What happens with wells when you shut them in is they build pressure during their shut-in time. And then when you turn them back online, they're producing at much higher volume then they were when you shut-in, and that incremental volume we call flush production, and that flush production usually makes up the amount of oil that was not produced during the shut-in period in fairly short order. So it's more like the production is being deferred temporarily rather than permanently lost or foregone."); Oct. 7, 2020 Hr'g Tr. 104:20-105:5 ("We would shut in, at least, two of the pads that are producing to the central gathering facility. They would be shut-in for those few months while we waited for a third-party to connect into the central gathering facility. And, at that point in time, we would turn all of those wells back on at significantly higher production rates then they were making at the time of shut-in. And we should be able to quickly recoup any deferred revenue that was lost during the shut-in period, given the flush production and the better contracts that we would have in place when that new production came online.").

[25] Oct. 7, 2020 Hr'g Tr. 89:24-90:3 (Platte River Contract: "[I]n the worst case, we would shut in those wells for a short period of time until the new company is connected, and then we would quickly make up that deferred oil production that was not produced during the short shut in period."); Oct. 7, 2020 Hr'g Tr. 105:10-15 (DJ South Contract: Shutting in wells for the time period it takes to install an alternative provider is better than assuming the contracts because "[t]he [DJ South Contract] . . . is charging us about three times the rate that their competitors are willing to charge. And shutting in for a few months is vastly outweighed by the economic benefit that the company's reserves in the area would receive for the next twenty to thirty years.").

Mr. Owens testified about the Grand Mesa TSAs. Mr. Owens testified that these contracts are projected to cost the Debtors approximately $100 million in annual spending.[26] Mr. Owens elaborated on the three possible alternatives to the Grand Mesa TSAs, which would result in millions of dollars in savings.[27]

Grand Mesa presented the testimony of Matthew O'Laughlin, a Principal of The Brattle Group, an economics and financial consulting firm.[28] Mr. O'Laughlin was a well-prepared and competent witness; however, he could not refute Mr. Owens' testimony. Mr. O'Laughlin opined that alternatives pose a "reasonable risk" of prorationing[29] but did not cite and was not aware of any prior instances of prorationing in the DJ Basin. Further, Mr. O'Laughlin did not model or provide the probability of prorationing by

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[26] Oct. 7, 2020 Hr'g Tr. 107:19-107:21 ("So far 2021, for example, we estimate a total spend with [Grand Mesa's] TSA to be $94 million."); Oct. 7, 2020 Hr'g Tr. 108:1-108:2 ("We anticipate a 2021 gross spend with [Bayswater] TSA to be $7.4 million."); Oct. 7, 2020 Hr'g Tr. 107:16-19 ("[T]he volume commitment is 58,000 barrels per day . . . [t]he term goes through October 2026 and the current rate we are charged is $4.40 per barrel."); Oct. 7, 2020 Hr'g Tr. 107:2-3 ("That escalates, I believe, at 2 percent per year through the end of the contract in 2026.").

[27] Oct. 7, 2020 Hr'g Tr. 108:5-10 ("We have seeked [sic] proposals from three companies that also provide transportation services through their pipelines from the Wattenberg Field in Platteville to Cushing, Oklahoma. The rates that we have received from those parties have been anywhere from $1.60 to $2.20."); Oct. 7, 2020 Hr'g Tr. 108:11-14 ("We anticipate that if we had one of those contracts our annual spend would be $25 to $35 million dollars which would equate to savings over our current contract or current Grand Mesa contract of $59 to $68 million dollars in 2021."). *Also compare* Debtors Ex. 37 to Debtors Ex. 57 (reflecting a savings of $59.2-$68.7 million in 2021 by using alternatives to the Grand Mesa TSA; and saving $7.4 million in 2021 by using alternatives to the Bayswater TSA").

[28] *See also* D.I. 892 (Declaration of Matthew O'Loughlin).

[29] Proration orders limit output from oil and gas wells in a field, for example, limiting the production of oil to the amount of the reasonable daily market demand and to require ratable production by all taking from the common source. *Champlin Ref. Co. v. Corp. Comm'n of State of Okl.*, 286 U.S. 210, 229, 52 S. Ct. 559, 563, 76 L. Ed. 1062 (1932). The Grand TSA at § 3.1 (stating that "Grand Mesa shall provide Services for all volumes up to the Fixed Monthly Payment Volume"), and at § 10.1 (stating that Extraction's capacity "shall not be reduced due to prorationing resulting from Pipeline System oversubscription due to shipper nominations exceeding Pipeline System capacity in any given Month."). The Bayswater TSA contains similar terms. In other words, the TSAs state that the Debtors' oil production would not be prorated (or slowed down), where if the TSAs are rejected, the Debtors' oil supply could be prorationed, or reduced.

alternative suppliers or a timeframe for such. Most troubling was Mr. O'Laughlin's opinion concerning the future price of oil, which is wholly inconsistent with the industry standard.[30]

Nothing about Mr. Owens' testimony leads the Court to believe that the Debtors were acting on a whim or were capricious.[31] In fact, Mr. Owens' testimony contained the cost benefit analysis of various alternatives, a well-reasoned discussion about why alternatives were preferable to continuing under the TSAs, and showed that the Debtors made a proper exercise of business judgment by rejecting the TSAs. Additionally, the rebuttal evidence of the Rejecting Counterparties did not rebut Mr. Owens testimony nor raise any concerns that the Debtors were acting on a whim or capriciously. Business judgment does not mean that the Debtors dotted every "i" and crossed every "t" – it means that the Debtors explored their options, thought through the alternatives, and

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[30] This is not the first time the Court has heard overly optimistic and unpersuasive projections of the price of oil using unorthodox methods.

[31] *See, e.g.*, Oct. 7, 2020 Hr'g Tr. 108:5-10 ("We have seeked[sic] proposals from three companies that also provide transportation services through their pipelines from the Wattenberg Field in Platteville to Cushing, Oklahoma. The rates that we have received from those parties have been anywhere from $1.60 to $2.20."); Oct. 7, 2020 Hr'g Tr. 76:1-6 ("[W]e recognized that for the most part alternative pipeline would not be immediately available to us and we had to understand exactly what our transaction would look like or what a transition plan would look like so that we could accurately model what the cost and effects would be to the company."); Oct. 7, 2020 Hr'g Tr. 88:22-25 ("[I]n their bid, they [alternative providers] provided what they thought the timing would be, so that was assumed in that three to six-month timeframe that we've talked about with the alternative providers."); Oct. 7, 2020 Hr'g Tr. 111:12-16 ("[W]e don't believe there will be any pro rationing or tightening in the near term, and that we should have ample access to markets and other pipeline providers in the event we did need to move any of our volumes on an alternative pipeline."); Oct. 7, 2020 Hr'g Tr. 89:24-90:3 ("[I]n the worst case, we would shut in those wells for a short period of time until the new company is connected, and then we would quickly make up that deferred oil production that was not produced during the short shut in period."); Oct. 7, 2020 Hr'g Tr. 108:11-14 ("We anticipate that if we had one of those [market rate alternative] contracts our annual spend would be $25 to $35 million dollars which would equate to savings over our current contract or current Grand Mesa contract of $59 to $68 million dollars in 2021.").

made a rationale decision based on the information available. Here, the Debtors spent considerable time analyzing whether rejection was in their business interest, they determined rejection provided them significant economic benefits, and they believe that will be able to successfully transition to alternative providers.

As a result, the Court finds that the Debtors' have presented sufficient evidence to support a showing of the proper exercise of their business judgment and the Rejection Counterparties have not rebutted the Debtors' evidence.

C. Covenant Running with the Land

The Rejection Counterparties contend that the TSAs contain "covenants that run with the land" and, thus, cannot be rejected.[32] The Court has previously held on summary judgment in two adversary proceedings brought by the Debtors against the Rejection Counterparties (at their insistence) that the TSA's do not contain covenants that run with the land. Nonetheless, the Court will assume, *arguendo*, for purposes of this section that the TSA's contain covenants that run with the land. This section does not alter or amend the Court's contrary decisions on summary judgment, which stand and are on appeal.

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[32] *See also Extraction Oil & Gas, Inc. v. Grand Mesa Pipeline, LLC (In re Extraction Oil & Gas, Inc.)*, Adv. Proc. No. 20-50816, Adv. D.I. 45 at 17 ("The Transportation Agreement does not create covenants that run with the land because these covenants fail to touch and concern Extraction's mineral estates and the original parties were not in privity of estate at the time of the creation of the covenants."); and *Extraction Oil & Gas, Inc. v. Platte River Midstream, LLC (In re Extraction Oil & Gas, Inc.)*, Adv. Proc. No. 20-50833, Adv. D.I. 54 at 24 ("The parties did not express an intent to allow any other covenants in the DJ South Contract to run with the land. Because the Platte River Contract does not clearly evince an intent for any covenants contained therein to run with the land and bind successors-to-title to any estate in real property, the Platte River Contract does not create covenants that run with the land as a matter of Colorado law." (citations omitted)).

Consistent with Section 365, when considering whether real covenants or instruments creating real covenants can be rejected, courts have generally considered whether those covenants meet the definition of an executory contract.[33] Most courts[34] that have held covenants running with the land cannot be rejected have found that the covenant was not an executory contract because it lacked material obligations on both sides[35] or did not otherwise constitute a contract.[36]

As cited by the Debtors, the court in *In re Arden & Howes Assocs., Ltd.* expressly rejected the notion that covenants running with the land insulate agreements from rejection.[37] In that case, confirmation of the "plan of reorganization turn[ed] on whether a restrictive use covenant that 'runs with the land' under state law can, after the lease is

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[33] *See, e.g., In re Foothills Texas, Inc.*, 476 B.R. 143, 151–53 (Bankr. D. Del. 2012) (holding that an overriding royalty interest did not meet the definition of an executory contract).

[34] *In In re Alta Mesa Res., Inc.*, the Court stated, without further analysis, that "[c]ontracts forming real property covenants are not executory." *Alta Mesa Holdings, LP v. Kingfisher Midstream, LLC (In re Alta Mesa Res, Inc.),* 613 B.R. 90, 99 (Bankr. S.D. Tex. 2019) (*citing In re Badlands Energy, Inc.*, 608 B.R. 854, 874 (Bankr. D. Colo. 2019)). In doing so, the Court cited *In re Badlands Energy, Inc.*, 608 B.R. at 875, which in turn quoted *In re Sabine Oil & Gas Corp.*, 567 B.R. 869, 874 (S.D.N.Y. 2017), *aff'd*, 734 Fed. Appx. 64 (2d Cir. 2018)). In *Sabine*, however, the court simply stated the parties agreed that a covenant that runs with the land creates an unrejectable property interest. *In re Sabine Oil & Gas Corp.*, 567 B.R. at 874. Similarly, in *Alta Mesa*, the matter of whether a contract that creates real covenants can be rejected under Section 365 was neither briefed for nor analyzed by the Court.

[35] *See In re Hayes*, ADV.07-00045-RBK, 2008 WL 8444812, at *11 (B.A.P. 9th Cir. Mar. 31, 2008) (concluding the bankruptcy court did not err because "there were no mutual obligations" remaining); *Gouveia v. Tazbir*, 37 F.3d 295, 299 (7th Cir. 1994) (concluding the real covenant was not rejectable because it "establishes an ongoing right of present (not merely future) enjoyment" and thus it lacked outstanding future material performance obligations) (emphasis in original)); *In re Foothills Texas, Inc.*, 476 B.R. at 151–53 (holding an overriding royalty interest did not meet the definition of an executory contract because there were not mutual material obligations remaining to be performed); *In re Banning Lewis Ranch Co.*, LLC, 532 B.R. 335, 343 (Bankr. D. Colo. 2015) ("Even if the Annexation Agreement could be considered a contract, the Court cannot find that it meets the Countryman definition of an executory contract.").

[36] *See, e.g., In re Banning Lewis Ranch Co.*, LLC, 532 B.R. at 343 ("[U]pon compliance with the . . . Colorado Municipal Annexation Act, the Annexation Agreement became a legislative act that set the boundaries of the City. At that point, the Annexation Agreement was no longer a contract, much less an executory one.").

[37] *In re Arden & Howe Assocs., Ltd.*, 152 B.R. 971, 975 (Bankr. E.D. Cal. 1993).

rejected, be enforced against one who acquires the shopping center from the trustee pursuant to the plan."[38] In *Arden & Howes*, the restrictive covenant at issue was recognized as running with the land.[39] Thus, the covenant's beneficiary sued to enjoin execution of a new lease to a third party that violated the covenant.[40] The beneficiary also opposed confirmation, arguing the reorganization plan "impermissibly [took] part of its leasehold, to wit, the restrictive use covenant that . . . runs with the land."[41] The court was not persuaded even though a "lease of real property is simultaneously a conveyance and a contract."[42] The court observed:

> Section 365(h) makes no mention of, and imparts no significance to, the concept of running with the land in connection with what constitutes the leasehold. The lessee is entitled to remain 'in possession of the leasehold' estate. The key is possession. What the lessee is entitled to retain consists of the essential elements of a lease— possession, term, and rent. Breaches of restrictive use covenants do not ordinarily work a dispossession.[43]

The court also rejected "the argument that successors who take from the trustee are nonetheless bound by a covenant that runs with the land."[44] Instead, the court held that the beneficiary was entitled to only the same remedy it would otherwise receive under the Bankruptcy Code—in the case of a lessee that remedy was an offset.[45] Thus, the court

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[38] *Id.* at 972.

[39] *Id.* at 975.

[40] *Id.* at 973.

[41] *Id.*

[42] *Id.* at 974.

[43] *Id.* at 975.

[44] *Id.*

[45] *See id.*

(i) placed no importance on the concept of covenants running with the land; (ii) allowed the rejection of a lease containing a covenant running with the land; and (iii) afforded the non-breaching party only the Bankruptcy Code's generally available remedy for the situation and did not allow any other remedy against successors to the burdened land.

The district court reached the same conclusion, noting "[t]he restrictive use covenant requires future performance, and courts have consistently held rejection relieves a trustee from covenants requiring future performance."[46] Section 365(h)(2) does not distinguish between affirmative covenants requiring expenditure of estate resources and the restrictive use covenant – section 365(h)(2) anticipates nonperformance of both types of covenants, since it provides a remedy for a trustee's "nonperformance of ***any obligation of the debtor under such lease***."[47] The court explained that "[r]ejection relieves a trustee from performing covenants requiring future performance, but does not deprive the lessee of its possessory property interest in the leased premises."[48] The same thing is true for the Debtors: rejection relieves the Debtors of their future obligations and only previously conferred rights are not rescinded.[49]

The Rejection Counterparties argue that covenants running with the land are real property in nature and not contractual obligations. The Court disagrees. Real covenants,

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[46] *Matter of Arden & Howe Associates, Ltd.*, 91-2299, 1993 WL 129784, at *4 (E.D. Cal. Mar. 1, 1993).

[47] *Matter of Arden & Howe Assocs., Ltd.*, No. 91-2299, 1993 WL 129784 at *3 (emphasis added).

[48] *Id.* (*citing In re Wood Comm Fund I, Inc.*, 116 B.R. 817, 818 (Bankr. N.D. Okla. 1990)).

[49] *Mission Prod. Holdings*, 139 S. Ct. at 1666 ("[W]e hold that under Section 365, a debtor's rejection of an executory contract in bankruptcy has the same effect as a breach outside bankruptcy. Such an act cannot rescind rights that the contract previously granted.").

or covenants that run with the land, are fundamentally creatures of contract. In *Thornton v. Schobe*,[50] the court considered whether an agreement not to build certain kinds of structures on a piece of property was a contractual agreement or a real property interest. The *Thornton* court held that agreement not to build a certain sort of building on certain land is not a transfer of an estate or interest therein nor a trust or power over it.[51] The *Thornton* court continues that "'Power' is used in the statute, as suggested by its connection with 'trust,' in the technical sense of power to convey or otherwise dispose of the lands as in wills, declarations of trust, trust deeds, and letters of attorney, and does not embrace restrictions of use."[52]

Farmers' High Line Canal & Reservoir Co. v. New Hampshire Real Estate Co.[53] also explains that an easement is a burden on the **land** whereas a contractual obligation is a burden on the **owner** of the land.[54] Thus an easement must be enforced with an injunctive type action and a contractual dispute is an action for money damages.

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[50] 79 Colo. 25, 28, 243 P. 617, 618 (1925).

[51] *Id.*

[52] *Id.*

[53] 40 Colo. 467, 480, 92 P. 290, 294 (1907).

[54] *Farmers' High Line Canal & Reservoir Co.*, 92 P. at 294 ("[I]f Eli Allen had an easement, such an easement was a burden solely upon the land, and not upon the owner. We agree with this, but the covenant running with the easement is personal: 'A covenant which runs with the land is a promise, the effect of which is to bind the promisor and his lawful successors to the burdened land for the benefit of the promisee and his lawful successors to the benefited land. According to this the covenant binds the person of the owner of the burdened land, provided he comes by his title legally, and benefits the owner of the benefited land, provided he comes by his title legally.'" (citations omitted)).

If the TSAs are rejected, this simply results in a breach of the contracts, and the covenants therein, and not a termination of those contracts.[55] In other words, rejection allows a debtor to stop performing its obligations, but the non-breaching party's rights remain. Here, the Rejection Counterparties are seeking the Debtors' performance under the midstream contracts. However, the Court concludes that these covenants that run with the land are not rights to the use of land, but contractual obligations on others that may be enforced against parties not bound by privity of contract but, rather, through privity of estate. Rejection will relieve the Debtors of all future performance obligations to deliver its oil to the Rejection Counterparties for transportation services (or pay any fee), and the Debtors may enter new transportation agreements with new counterparties or find alternatives to transporting its products.[56]

However, *even if* the TSAs contain covenants running with the land, which they do not, the question then becomes what effect the covenants have on the Debtors' property post rejection. The answer is simple: any covenant running with the land still exists (as the contract still exists), but it is unenforceable against the Debtors and their assigns after the Rejection Counterparties' claims are satisfied as part of the reorganization process. Upon rejection, the Rejection Counterparties' claims under the

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[55] *See* 11 U.S.C. § 365(h) ("Except as provided in subsections (h)(2) and (i)(2) of this section, the rejection of an executory contract or unexpired lease of the debtor constitutes a breach of such contract or lease . . . .").

[56] The Court was troubled by the testimony of Mr. McGillis, which was also discussed during closing argument, that Platte River had obtained an *ex parte* TRO in Colorado State Court against one of the Debtors' alternative trucking companies based on the terms of the Platte River TSA's. Notwithstanding that the action may have been a violation of the automatic stay, it is based on a theory that does not hold water post-rejection as Platte River will have a rejection claim, and, thus, an adequate remedy at law.

TSAs will be compensated, rendering the claims fully satisfied and incapable of subsequent enforcement against the Debtors and its assigns through either privity of contract or privity of estate.[57] Importantly, the Rejection Counterparties cannot seek duplicative recovery for the breached covenants by using privity of estate as justification for suing successors to the Debtors' real property interests for a breach of the fully satisfied covenants.[58]

Like the covenant to pay rent in leases—covenants running with the leasehold estate—the TSAs explicitly provide for a specific amount of monetary damages to remedy a breach of the alleged real covenants. Consequently, the Rejection Counterparties will be fully compensated for the deemed prepetition breach of their contracts with an unsecured claim for money damages, pursuant to section 365.

Specifically, as to Platte River**,** Platte River expressly granted the Debtors the unilateral right to "terminate" the agreement upon satisfaction of its contractual obligations via payment of the Total Financial Commitment. As evidenced in the Platte River Contract and the DJ South Contract, the Total Financial Commitment means "the

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[57] *See also Extraction Oil & Gas, Inc. v. Grand Mesa Pipeline, LLC (In re Extraction Oil & Gas, Inc.)*, Adv. Proc. No. 20-50816, Adv. D.I. 45 at 2 (holding that "the dedication and commitment covenant does not touch or concern the land, and there is no privity of the estate.."); and *Extraction Oil & Gas, Inc. v. Platte River Midstream, LLC (In re Extraction Oil & Gas, Inc.)*, Adv. Proc. No. 20-50833, Adv. D.I. 54 at 2 ("Under the unambiguous terms of the Platte River Contract, none of the required elements are met—the parties did not intend to create a covenant that runs with the land, the covenant does not touch or concern the land, and there is no privity of the estate.").

[58] *Leprino Foods Co. v. Factory Mut. Ins. Co.*, 653 F.3d 1121, 1134 (10th Cir. 2011) (applying Colorado law) ("In a breach of contract action, the objective is to place the injured party in the same position it would have been in but for the breach. A double or duplicative recovery for a single injury, however, is invalid. Under Colorado law, a plaintiff may not receive a double recovery for the same injuries or losses arising from the same conduct." (citations omitted)).

aggregate of the Fixed Monthly Payment due under this Agreement for all Months of the Term remaining at such time." "Upon satisfaction of either of such obligations, (i) the Committed Volume shall immediately be reduced to zero and (ii) [the Debtors] may elect to terminate [the] Agreement upon written notice to [the counter party]."[59] Indeed, the Debtors may even opt to accelerate satisfaction of the Total Volume Commitment, and all of its obligations under these contracts, through payment. Thus, as to Platte River, it is made clear in their contracts and proofs of claims, monetary damages are easily calculable and specific performance is both unavailable and inappropriate.

The same thing is true for the Grand Mesa TSAs. Again, the Debtors' commitments can be satisfied in full by either: (i) shipping certain amounts of crude petroleum within certain timeframes or (ii) "by satisfaction of [the Debtors'] Total Financial Commitment." Again, at the Debtors' option, they may accelerate the satisfaction of the Total Financial Commitment, and their obligations under the Grand Mesa TSA, through payment.[60] Again, monetary damages are easily calculable.

As a result, all the TSAs provide for money damages, which further supports that the covenants running with the land are contractual in nature; thus allowing these contracts to be rejected pursuant to Section 365 of the Bankruptcy Code even if they contain covenants running with the land, which they do not.

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[59] Platte River Contract, at §3.1; and DJ South Contract at § 4.1.

[60] Bayswater Contract at § 8.2 ("For the avoidance of doubt, the Total Financial Commitment will be satisfied by payment by [the Debtors] of the aggregate of the Fixed Monthly Payments in accordance with the terms of this Agreement, or at [the Debtors'] option, any payment made by [the Debtors] to accelerate the satisfaction of that obligation."); Grand Mesa Contract at § 8.2 (same).

D. FERC Inquiry

Platte River and Grand Mesa have asserted that FERC should hold a proceeding on whether the Court should approve rejection of the contracts.

FERC has held that "the Commission neither presumes to sit in judgment of rejection motions nor seeks to abrogate the role of adjudicating bankruptcy proceedings. The Commission recognizes that rendering a determination on rejection motions is solely within the province of the bankruptcy court."[61] Similarly, the Court recently described the Court and FERC – having a "parallel exclusive jurisdiction" - a debtor seeking to reject a FERC jurisdictional contract through bankruptcy must obtain approval from the bankruptcy court to reject the contract but a debtor may go before FERC to abrogate or modify the filed rate in that contract. They are two separate matters. Here, the Debtors are seeking to reject the contracts and not to abrogate or to modify the rates therein.[62] Moreover, as the Court recently held in this case, an order authorizing rejection does not abrogate or modify a filed rate.[63] Congress provided FERC limited regulatory jurisdiction over interstate oil pipeline transportation services (just as it provided this

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[61] *ETC Tiger Pipeline, LLC*, 171 FERC ¶ 61,248, at 62,828 (June 22, 2020) (*quoting NextEra Energy, Inc. v. Pac. Gas & Elec. Co.*, 166 FERC ¶ 61,049 (2019) and *Exelon Corp. v. Pac. Gas & Elec. Co.*, 166 FERC ¶ 61,053 (2019) (Exelon), order on reh'g, NextEra, Inc. v. Pac. Gas & Elec. Co., 167 FERC ¶ 61,096 (2019)).

[62] "FERC's jurisdiction concerning rate setting is unaltered by rejection." *Ultra Petroleum Corp.*, No. 20-32631, 2020 WL 4940240 at *12.

[63] D.I. 770, Letter Clarifying Oral Ruling on October 2, 2020 (entered 10/4/2020) ("FERC's recent statement in *ETC Tiger Pipeline, LLC* that the [r]ejection of a Commission-jurisdictional contract in bankruptcy court alters the essential terms and conditions of a contract that is also a filed rate is incorrect. It does no such thing. The Supreme Court recently confirmed in *Mission Product Holdings* that "[a]ccording to Section 365(g), 'the rejection of an executory contract[ ] constitutes a breach of such contract . . . .'" *Mission Product Holdings*, 139 S. Ct. at 1659. The effect of a debtor's rejection of a contract under section 365 is that "[i]t gives the counterparty a claim for damages, while leaving intact the rights the counterparty has received under the contract." *Id.*, 139 S. Ct. at 1661.)

Court with limited jurisdiction), and this limited regulatory jurisdiction is not a legitimate basis to usurp this Court's authority to rule on Debtors' motion to reject in this proceeding.

Interestingly, FERC argued that because rejection claims would be paid in "plan dollars" or "claim dollars" rather than dollar-for-dollar, that rejection of the TSAs would necessarily be abrogating the rates. First, and not to be flippant, that is how bankruptcy works – bankruptcy is about consolidating assets and equitable distribution of available funds. Congress established the bankruptcy waterfall of distribution, much like it created FERC, and nothing in the Bankruptcy Code nor the FERC regulation excepts or prioritizes either of the statutes.

Second, nothing in this Court's ruling changes the rates, including for the time from the petition date to today. Such rate claims will be claims against the estate and will be paid by the Debtors, pursuant to a plan and subject to the Bankruptcy Code's waterfall. As a result, the *only* possible "claim dollar" payout would be for unpaid usage of the pipelines, as well as rejection damages. And to be clear, nothing is affecting the rate charged – the Rejection Counterparties have and will file claims at the rates approved by FERC and this Court is doing nothing to abrogate those approved rates.[64] How and when those claims will be paid-out is an issue for the plan and confirmation process.

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[64] *In re Mirant Corp.*, 378 F.3d 511, 520 (5th Cir. 2004) ("Mirant's rejection of the Back–to–Back Agreement was approved, then PEPCO's unsecured claim against the bankruptcy estate would be based upon the amount of electricity it would have otherwise sold to Mirant under that agreement at the filed rate. Thus, the damages calculation from the rejection of a contract is analogous to the damages calculation we previously approved in Gulf States because the award calculation is based upon the filed rate." (citation omitted); *Gulf States Utilities Co. v. Alabama Power Co.*, 824 F.2d 1465, 1471 (5th Cir.), *amended*, 831 F.2d 557

As a result, the Court rejects the argument that payment of claims through the plan and confirmation process is an abrogation of FERC approved rates.

E. Public Interest

Platte River and Grand Mesa claim that rejection would not be in the public interest because (i) certain alternatives would require trucking of crude oil, which they contend is more risky and not as environmentally sound, (ii) rejection would require the shutting-in of wells, which may lead to decreased production, (iii) rejection would harm the community-at-large due to the significant impact on the Rejection Counterparties (i.e. would the Rejection Counterparties continue to operate? Would they be forced to shutter their businesses, fire their employees, and have the pipelines fall into disrepair?); and (iv) rejection would impact the oil markets in general. The Rejection Counterparties assert that the three-prong test articulated in *Mirant* should apply here. *Mirant* set forth a more rigorous standard for rejecting a contract for the purchase of electricity,[65] which was adopted, in part, in *Ultra Petroleum* relating to the rejection of a natural gas contract.[66] The three prongs are: (i) determining if the executory contract was excepted from rejection under section 365; (ii) scrutinizing "the impact of rejection on the public interest and on the supply of natural gas to consumers;" and (iii) after determining the public

(5th Cir. 1987) (damages from breach claims challenging the quantity purchased are not preempted but they must be calculated using the filed rate).

[65] *In re Mirant Corp.*, 378 F.3d at 525 (upon remand "the courts should carefully scrutinize the impact of rejection upon the public interest and should, *inter alia*, ensure that rejection does not cause any disruption in the supply of electricity to other public utilities or to consumers.").

[66] *Ultra Petroleum Corp.*, No. 20-32631, 2020 WL 4940240 at *8.

interest and supply concerns, the Court must "weigh those concerns against the [a]greement's burden on [the] reorganization."[67]

No court has applied the *Mirant* test to oil contracts that are at issue in the TSAs. This is not surprising as FERC has a more limited jurisdiction over oil pipelines than of gas and power contracts (which were at issue in *Mirant* and *Ultra*).[68] The Interstate Commerce Act ("ICA") is applicable to oil pipelines. It is important to note that the ICA was enacted to address monopoly power.[69] Furthermore, the ICA applies a different "public interest" test than other federal statutes (interestingly, the ICA never uses the words "public interest"). In the ICA, the "public interest" encompasses "just and reasonable pipeline rates and terms" and "an efficient petroleum market."[70] By contrast, for purposes of the Natural Gas Act (the "NGA"), the "public interest" encompasses "plentiful and uninterrupted supplies of fuel to the public."[71] That the ICA and NGA would provide different standards for assessing the public interest is not surprising; these standards arise from the "different economic context[s]" in which Congress passed the statutes, and manifest themselves through FERC's corresponding and distinct regulatory approaches.

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[67] *Id.*

[68] Oct. 20, 2020 Hr'g, Tr. 11:5-12 ("Q: And are there any significant differences between the tools that FERC was given to regulate oil pipelines as compared with gas pipelines? A [Dr. Makholm] Yes. As the regulations for gas was grounded in a regulatory function, the FERC was given duties over regulated entry and exit, and over regulated accounting. So, either it was not given -- it was handed to the regulator under the original Interstate Commerce Act for oil pipelines.").

[69] Oct. 20, 2020 Hr'g Tr. 10:4-11:12.

[70] *See* Makholm Decl. (attached as Ex. 19 to the Debtors' reply, D.I. 681) at 5.

[71] *Id.* at 4.

With that background in mind, the Court must start its analysis with Section 365. Section 365 of the Bankruptcy Code does not mandate that the Court consider public policy or public interest. It is irrelevant for Section 365's purposes. This is not a proceeding before FERC to modify or to abrogate a filed rate. In fact, allowing rejection in order for companies in bankruptcy to reorganize *is in the public interest*.[72] The Supreme Court has held that "the authority to reject an executory contract is vital to the basic purpose to a Chapter 11 reorganization, because rejection can release the debtor's estate from burdensome obligations that can impede a successful reorganization."[73]

The Court does not believe that a heightened scrutiny, including consideration of the public interest, is warranted. However, assuming *arguendo* that it is, the Court finds that the balance tips in favor of the Debtors. And, as this is a Court of equity, the Court will consider and evaluate the balance of equities to each of the parties and the impact on the public at large.[74]

Moreover, like the *Ultra Petroleum* court considered, the consideration of the macroeconomic effects on future use of oil pipelines is unfounded – that is a policy determination for Congress and not for this Court.[75] However, the Court, in its balance

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[72] *N.L.R.B. v. Bildisco & Bildisco*, 465 U.S. 513, 527-28, 104 S. Ct. 1188, 1197, 79 L. Ed. 2d 482 (1984) ("The Bankruptcy Code does not authorize free-wheeling consideration of every conceivable equity, but rather only how the equities relate to the success of the reorganization. . . . The fundamental purpose of reorganization is to prevent a debtor from going into liquidation, with an attendant loss of jobs and possible misuse of economic resources." (citing H.R.Rep. No. 95-595, p. 220 (1977)).

[73] *Bildisco*, 465 U.S. at 528.

[74] *Bildisco*, 465 U.S. at 527 ("The Bankruptcy Court is a court of equity, and in making [the determination to reject a collectively bargaining agreement] is in a very real sense balancing the equities . . .").

[75] *Ultra Petroleum Corp.*, No. 20-32631, 2020 WL 4940240 at *9.

of equities consideration, will look at whether the rejection of the TSAs "threatens the public health, safety or welfare."[76]

At trial, the Debtors presented the testimony of Dr. Jeff Makholm. Dr. Makholm was clearly intelligent, articulate, and a bit too sure of himself, but well qualified and persuasive. Dr. Makholm testified that (i) any consideration of public interest must account for the FERC's lighter regulation of oil pipelines contracts versus gas or power;[77] (ii) the ICA was enacted to address monopoly power;[78] (iii) the *Mobile-Sierra* doctrine has not been extended to the oil pipeline context;[79] and (iv) rejection will not discernibly affect the relevant market.[80] Dr. Makholm's testimony concluded that rejection of the TSAs would be in the public interest because it would promote competitive oil markets.[81]

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[76] *Id.*

[77] Oct. 20, 2020 Hr'g Tr. 10:4-11:12.

[78] Oct. 20, 2020 Hr'g Tr. 10:9-16.

[79] Oct. 20 Hr'g Tr 19:15-20:6. The *Mobile-Sierra* doctrine, which originated from two Supreme Court decisions issued in 1956, prohibits FERC from modifying or abrogating existing contracts under the Federal Power Act ("FPA") and NGA unless required to protect the public interest (*not* the ICA). *United Gas Pipe Line Co. v. Mobile Gas Serv. Co.*, 350 U.S. 332, 344 (1956) ("*Mobile*"); *Fed. Power Comm'n v. Sierra Pac. Power Co.*, 350 U.S. 348, 355 (1956) ("*Sierra*"). Mobile and Sierra were decided under the "substantially identical" ratemaking provisions of the NGA and the FPA, which is why the judicial decisions interpreting the *Mobile-Sierra* doctrine interchangeably cite cases decided under the NGA and FPA. *See, e.g., Arkansas La. Gas Co. v. Hall*, 453 U.S. 571, 577 n.7 (1981) (citations omitted).

[80] Oct. 20, 2020 Hr'g Tr. 13:20-14:5.

[81] Oct. 20, 2020 Hr'g Tr. 19:15-20:11. Dr. Makholm's testimony is as follows:

> Q Dr. Makholm, you understand that the counterparties in this case have raised concerns more generally about the public interest such as potential impacts from trucking oil; is that right?
>
> A That's what I understand, yes.
>
> Q And do you believe that those are appropriate public interest considerations under the ICA?
>
> A No, not for the FERC. The local trucking --
>
> Q And why is that?

In response, Grand Mesa submitted the testimony of Commissioner Branko Terzic.[82] Commissioner Terzic stated that, although the ICA does not define "public policy," he believed that the *Mobile-Sierra* doctrine is instructive guidance.[83] The *Mobile-Sierra* doctrine provides that a party seeking to avoid its contractual obligations may do so only after it meets the burden of demonstrating "'unequivocal public necessity' or 'extraordinary circumstances'" where "the public interest will be severely harmed" by continued compliance.[84] Commissioner Terzic continued that "[g]iven the breadth of the meaning of public interest in relation to energy regulation, [he] groups the multitude of factors relating to [the Debtors'] proposed noncompliance with the TSAs into five general buckets: (a) Financing concerns; (b) Economic concerns; (c) Environmental concerns; (d) Safety concerns; and (e) Other issues of public importance, including regulatory

> A Trucking pipeline safety, other issues associated with those aspects of the public interest while looming important for local communities, don't fall under the egis of the Interstate Congress Act as an item for the FERC to oversee.
>
> Q So, in conclusion, do you believe that there will be any harm to the public interest if the Bankruptcy Court grants Extraction's motion to reject?
>
> A No.
>
> Q And why is that?
>
> A Because the competitive market for fuel, which was the impetus, and the practice of applying the Interstate Commerce Act to oil pipelines both by the Interstate Commerce Commission and by the FERC is unaffected by rejection.

Id.

[82] D.I. 891 (the "Terzic Decl.").

[83] Terzic Decl. at ¶ 9.

[84] *Id.*

procedure and labor impacts."[85] Commissioner Terzic testified that the Debtors' rejection of the TSAs would have a huge impact on Grand Mesa and its other customers, it would impact labor and trucking (the alternative to using the pipeline) and it would also have safety and environmental implications.[86] Commissioner Terzic also testified that *but for* the Debtors, Grand Mesa would not have built the pipeline or even been approved by FERC. The Court finds that Commissioner Terzic was a forceful, honest, and confident witness. The Court believes he was an outstanding Commissioner in Wisconsin and on FERC. Nonetheless, his testimony on the public interest was circular and not enlightening. Moreover, it provided no specifics relevant to the Debtors. The Court gives little weight to his testimony.

Furthermore, Mr. David Haag, the President and Chief Executive Officer of Brown Williams Moorhead & Quinn, Inc., an energy consulting firm, testified on behalf of Platte River.[87] Mr. Haag opined that trucking may not be available to the Debtors and that alternative pipelines may take years to complete and, as a result, it would be against public policy to reject the TSAs. Mr. Haag mentioned four alternatives available to the Debtors: (i) shut-in the wells, which Mr. Haag states will affect public interest by decreasing supply, which will have an impact as these wells are already drilled. However, the Debtors' do not plan to shut-in a majority of their wells – of course it is an

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[85] *Id.* at ¶ 11.

[86] *Id.* at ¶¶ 13-25. *But see* Oct. 20, 2020 Hr'g Tr. (Makholm) 18:4-19:14 (disagreeing with Mr. Terzic's conclusions).

[87] Expert Report of David J. Haag, attached to Platte River's objection to the Motions (D.I. 655 and 656) at Ex. D.

option for the Debtors, but the Debtors have not made that determination; (ii) alternative modes of transporting the oil (for example: (a) an alternative pipeline, (b) marine vessel, (c) rail, and (d) trucks); however, FERC does not regulate trucking of oil, nor has Mr. Haag analyzed the impact of public interest by additional traffic caused by trucks or whether the alternatives could be in the best interests of the Debtors. Furthermore, Mr. Haag commented that new pipelines could take years to build and be very expensive – but, yet again did not study the impact of such alternative; (iii) impact on the Rejection Counterparties – Mr. Haag testified that rejection of the TSAs could cause the midstream providers to become insolvent and may potentially cause the pipelines to fall into disrepair. However, Mr. Haag did not analyze whether the pipelines could be sold or whether they could renegotiate new rates and contracts – in other words, Mr. Haag's testimony was hypothetical and contingent rather than presenting quantifiable evidence. Furthermore, although rejection would have a great deal of impact on the Rejection Counterparties – this is not the same as "public interest;" and (iv) Mr. Haag testified that downstream producers would be impacted by duplicate pipelines and delay in receipt of the oil – again, the testimony of Mr. Owens who testified that alternative pipelines were within a mile or so of the Debtors' wells and Dr. Makholm's testimony concerning the impact on the oil markets refute Mr. Haag's generalized claims.

Mr. Haag's credentials are unimpressive; he was an evasive and overly verbose witness. Several times he appeared to either not understand or simply to ignore the

questions. Furthermore, Mr. Haag spoke with a lack of clarity. The court gives zero weight to his testimony.

Furthermore, when balancing the equities, the Court must consider whether the threat to the public was imminent or calculable. Might it slow down oil production or potentially be more expensive to the consumer – no, based on Dr. Makholm's testimony. In hindsight, could the Debtors' business judgment in rejecting these contracts be a business misstep? Potentially. But the Court must look at the evidence before it and not speculate.

The Court is sympathetic to all the Rejection Counterparties and their broken expectation of doing business with the Debtors in the long-term. For example, the relationship with the Debtors plays into the counterparties' own financial projections and was a basis for the financing of their construction of the pipelines. Clearly, the Rejection Counterparties relied on the TSAs and the Debtors' oil and gas is a large percentage of their respective businesses. Nonetheless, similar situations arise in bankruptcy contexts all the time – landlords build out floors or entire buildings for their tenants; factories are built based on business expectations. Here, pipelines were constructed, and permits obtained. The reality is that the Debtors cannot continue to perform under these contracts.[88] The Debtors filed for bankruptcy to relieve themselves of some of their

[88] Oct. 7, 2020 Hr'g Tr. 73:7-14 (Mr. Owens: "Rather than really providing a benefit to the company since oil prices collapsed almost immediately after they entered into the first agreement, these contracts have been a very large burden on the company. With the lower commodity prices, we've had to slow our development plan which made it extremely difficult for us to comply with the minimum volume commitments or minimal financial commitments that are associated with the majority of these contracts."). Mr. Owens continued:

obligations and are restructuring their debt, including rejecting these TSAs. Furthermore, although there is testimony that trucking may cause additional environmental harm from accidents and weather-related delays, it is not enough to force the Debtors to perform under the TSAs at an extreme financial hardship.

Thus, although the Rejection Counterparties may be commercially harmed by these rejections, the Court finds that the public, as a whole, will not be harmed by the rejection; and any harm is not an imminent threat to the health, safety or welfare of the public-at-large. The rejection will not affect the ability of pipelines to offer reasonable rates and terms, nor affect the petroleum market more broadly.[89] On balance, the public will benefit from the Debtors' continued production, their workers remaining employed, and potentially additional jobs and contracts from the Debtors having to re-route its oil. Overall, the Debtors' creditors and the public-at-large will be in a better position after the rejection of these TSAs. Furthermore, the Rejection Counterparties will be entitled to file proofs of claim based on their respective rejection damages.

> Q And what form of analysis were prepared by Alvarez & Marsal or the debtors to assist in making the rejection for assumption decision?
>
> A We looked at several things. First, we had to understand what continued performance under each contract would cost the company, and how that would affect the company's liquidity in the short term. Second, we performed a market check to see what current rates were being offered from competitors of our Midstream companies in light of the dramatic drop in crude prices and the historic drop in rigs running into basin to an all-time low. We also needed to understand the alternatives to each contract in the short term and the long term. And, finally, I'd say we decided whether rejection was a better outcome for the business going forward or not.

Oct. 7, 2020 Hr'g Tr. 75:1-15.

[89] Makholm Decl. at 2-3.

F. *Nunc Pro Tunc* Rejection of the TSAs

The Rejection Counterparties argue that the Court should not grant relief *nunc pro tunc* to the Petition Date, arguing that the equities weigh against such a ruling on the ground that Debtors have continued to ship on their pipelines. "[C]ourts have held that bankruptcy courts may exercise their equitable powers in granting such a retroactive order when doing so promotes the purposes of Section 365(a). Courts have further held that the retroactive rejection of executory contracts and unexpired leases may be approved 'after balancing the equities' of a case and concluding that such equities weigh in favor of the debtor."[90]

Here, the Debtors presented evidence analyzing their costs and benefits, and determining that the TSAs are no longer beneficial to their estates. The Debtors have sought the relief requested as soon as they determined that the rejection of the TSAs was in the best interests of their estates. Without a retroactive date of rejection, the Debtors could be forced to incur unnecessary administrative charges and contractual obligations in connection with the TSAs that do not provide an equivalent benefit to the Debtors' estates (such as minimum volumes and deficiency payment obligations). Furthermore, each of the Rejection Counterparties has benefited from Debtors continuing to ship on their pipelines, which means that the Debtors have been paying for the services provided while the rejection has been litigated. Lastly, the Rejection Counterparties have done

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[90] *In re Rupari Holding Corp.*, No. 17-10793 (KJC), 2017 WL 5903498, at *6 (Bankr. D. Del. Nov. 28, 2017) (footnotes and citations omitted). "[T]he court's power to grant retroactive relief is derived from the bankruptcy court's equitable powers so long as it promotes the purposes of § 365(a)." *In re Chi-Chi's, Inc.*, 305 B.R. 396, 399 (Bankr. D. Del. 2004) (*citing In re Thinking Machines Corp.*, 67 F.3d 1021, 1028 (1st Cir. 1995)).

nothing to mitigate their damages, such as filing a motion to terminate the TSAs or petitioning FERC to request waiver to be permitted to re-market the associated capacity.

Thus, the Court will authorize *nunc pro tunc* rejection of the TSAs.

CONCLUSION

For the foregoing reasons, the Court will grant the Motions and enter relief, *nunc pro tunc* to the dates specified in the Motions. The Court requests that the Debtors circulate and submit an agreed proposed order or orders. If the parties cannot agree on a proposed forms of order, submit competing Certificates of Counsel and the Court will decide.

Christopher S. Sontchi, Chief Judge
United States Bankruptcy Court

Dated: November 2, 2020

EXHIBIT I

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE DISTRICT OF DELAWARE

In re:	Chapter 11
EXTRACTION OIL & GAS, INC. *et al.*,[1]	Case No. 20-11548 (CSS)
Debtors.	(Jointly Administered)
EXTRACTION OIL & GAS, INC.,	
Plaintiff,	Adversary Proceeding
PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC	Adv. Proc. No. 20-50833 (CSS)
Defendants.	

PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC'S RESPONSE IN OPPOSITION TO EXTRACTION OIL & GAS, INC.'S MOTION FOR SUMMARY JUDGMENT[2]

[1] The Debtors in the Chapter 11 Cases, along with the last four digits of each Debtor's federal tax identification number, are: Extraction Oil & Gas, Inc. (3923); 7N, LLC (4912); 8 North, LLC (0904); Axis Exploration, LLC (8170); Extraction Finance Corp. (7117); Mountaintop Minerals, LLC (7256); Northwest Corridor Holdings, LLC (9353); Table Mountain Resources, LLC (5070); XOG Services, LLC (6915); and XTR Midstream, LLC (5624). The location of the Debtors' principal place of business is 370 17th Street, Suite 5300, Denver, Colorado 80202.

[2] The Companies submit a Declaration of Rogan McGillis, attached hereto as Exhibit BB, attesting to the authenticity of the Companies' business records referenced within and attached herewith.

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Exhibit AA	Extraction Oil & Gas, Inc., Quarterly Report (Form 10-Q) at 11 (May 11, 2020)
Exhibit BB	Authenticating Declaration of Rogan McGillis Regarding the Companies' Business Records (Sept. 18, 2020)

Platte River Midstream, LLC ("PRM") and DJ South Gathering, LLC ("DJ South") (together, the "Companies") hereby submit this Response in Opposition to Extraction Oil & Gas, Inc.'s ("Extraction's") Motion for Summary Judgment (the "Motion").

INTRODUCTION AND SUMMARY OF THE ARGUMENT

1. The Companies and Extraction are parties to two long-term contracts, pursuant to which the Companies have built, installed, and operated two underground crude oil pipeline systems. These systems were custom built to transport Extraction's crude oil from its wells located in several Colorado counties to downstream locations in Weld County, Colorado.

2. The Companies were created to build and operate the transportation systems for Extraction. Indeed, Extraction's affiliates owned interests in the Companies as joint ventures.

3. The Companies invested hundreds of millions of dollars in obtaining permits, securing real property interests, installing underground pipelines, and otherwise ensuring that Extraction can transport its current and future production by pipeline in urban areas north of Denver. In return, Extraction dedicated all of its crude oil interests within certain defined areas, whether produced or in the ground, to be delivered into the Companies' pipelines for the durations of the agreements. Without the dedications, the pipelines would not have been built.

4. Extraction has filed an adversary proceeding seeking declarations that the agreements do not create covenants running with the land, and therefore can be rejected as executory contracts. *See* Adversary Compl. [Dkt. #1] at ¶¶ 31-49. Extraction immediately moved for summary judgment based solely on the agreements' language. *See* Mot. at 1, 8-9.

5. Under Colorado law, a contract creates a covenant running with the land when (1) the parties intend to create this covenant, and (2) the underlying agreement touches and concerns the land. *See Reishus v. Bullmasters, LLC*, 409 P.3d 435, 440 (Colo. App. 2016). Based on this standard, summary judgment should be denied for multiple reasons:

First, Extraction's argument ignores numerous provisions in the parties' agreements that demonstrate the parties' intent to create covenants running with the land, and that the agreements touch and concern the land. When the agreements are read as a whole, Extraction's Motion should be denied. *See Reishus*, 409 P.3d at 441 ("[W]e do not read individual provisions in isolation when deciding whether a covenant is real or personal; instead, we look at the covenant as a whole.").

Second, the agreements must be considered in light of the factual circumstances surrounding the parties' intent and the agreements' relationship to the property, all of which present factual issues Extraction ignores. *See Lookout Mtn. Paradise Hills Homeowners' Ass'n v. Viewpoint Assocs.*, 867 P.2d 70, 73-76 (Colo. App. 1993) (evaluating agreement to determine whether covenant ran with the land). This is particularly relevant to other contracts and assignments confirming the parties' intent. *See infra* at ¶ 21, Sec. I; *see also Meredith v. Ramsdell*, 384 P.2d 941, 944 (Colo. 1963) ("It is elementary that an agreement may be evidenced by several writings, which, when connected, show the parties, subject matter, terms, and consideration. Such concept has been applied to oil and gas contracts.") (citations omitted).

Third, Extraction insists on imposing legal elements for covenants running with the land that do not exist under Colorado law, s*ee* Mot. at 13-27, such as horizontal privity or a specific "legal relationship" to create a covenant. *See Reishus*, 409 P.3d at 441.

Fourth, at a minimum, the contracts are ambiguous. *See Cheyenne Mtn. Sch. Dist. No. 12 v. Thompson*, 861 P.2d 711, 715 (Colo. 1993) (holding contract "is ambiguous when it is reasonably susceptible to more than one meaning") (citation and internal quotations omitted). The parties' intent must be considered based on the facts surrounding (i) the parties' reasons for entering into the contracts, (ii) their negotiations, (iii) their contractual obligations, and (iv) their

performance under the contracts. *See infra* Sec. I (identifying facts describing these circumstances). These issues cannot be resolved on summary judgment.

STATEMENT OF FACTS

6. Extraction relies only on its interpretation of the parties' contracts. *See* Mot. at 3-7. Its interpretation is argument, not evidence. *See Finjan, Inc. v. Symantec Corp.*, 2013 WL 5302560, at *25 (D. Del. Sept. 19, 2013) ("It is well established that attorney argument does not constitute evidence.") (citations omitted). Its interpretation also is incomplete and inaccurate. The relevant contractual terms, and the relevant facts, are presented below.

The Companies and In-Field Transportation Systems

7. ARB Midstream, LLC ("ARB") is the manager and majority owner of the Companies. *See* Declaration of Rogan McGillis, attached as Exhibit A at ¶¶ 24(a), 31. ARB builds and operates pipeline systems to transport oil and other liquid hydrocarbons. *See id.* at ¶ 4. These are known as "in-field systems," because they transport oil within the specific production area, as opposed to larger pipelines that transport production over long distances. *See id.*

8. Building an in-field system requires the installation of dozens, even hundreds, of miles of pipelines buried several feet underground, which in turn requires ARB to obtain rights of ways or easements from property owners, purchase surface lands for facilities, and obtain permits from local and state governments. *See id.* at ¶ 6. Producers also must grant access to their surface and mineral estates to connect the transportation pipelines. *See id.*

9. In-field systems require a substantial upfront financial investment, because the pipelines must be installed before they can deliver production. *See id.* at ¶ 7. Buying rights of ways, easements, surfaces locations, purchasing and building a network of steel pipelines, and installing other facilities costs many millions of dollars. *See id*. That investment is recovered years later through the producer's payment of monthly charges. *See id*.

10. To justify the upfront investment, transportation companies commonly require producers to dedicate their acreage to the pipelines for the term of the agreement. *See id.* at ¶ 8. The language of a dedication can vary, but the intent is the same: to ensure the producer delivers production into the pipelines so the transportation company recovers the cost of installing an in-field system. *See id.* at ¶ 12. Without the dedication, which binds the producer and its successors, in-field systems would not obtain financing and could not be economically built. *See id.* at ¶ 10.

11. A dedicated pipeline system creates substantial value for producers. *See id.* at ¶ 13. Access to a dedicated system ensures that production will be transported to market for sale. *See id*. Mineral leaseholds with dedicated transportation generally are more valuable than leaseholds without such dedications. *See id*.

12. Pipelines are particularly important in populated areas, such as the Denver-Julesburg Basin, a production area north of Denver, Colorado (the "DJ Basin"). *See id.* at ¶ 14. Without pipelines, the producer's only alternative is to use tanker trucks to transport its crude oil. *See id*. Tanker trucks are noisy, increase traffic, and transport a hazardous product on Colorado's roads. *See id*. Residents of towns such as Greeley, Broomfield, and Aurora have opposed oil and gas production unless the producer agrees to use pipelines instead of trucks. *See id.* at ¶ 15. Some communities have required producers to use pipelines. *See id*. at ¶¶ 14-15.

Platte River Midstream and Its Transportation Agreement with Extraction

13. In September 2016, ARB acquired PRM as a platform to build and operate a crude oil transportation system in Larimer and Weld Counties, Colorado (the "PRM Transportation System"). *See id*. at ¶ 16.

14. In late 2016, Extraction began negotiating with ARB to expand the PRM Transportation System to connect to Extraction's current and planned wells in Larimer and Weld Counties. *See id*. at ¶ 18. During negotiations, Extraction explained its aggressive drilling

program, and therefore needed a transportation company with the resources and commitment necessary to quickly connect to Extraction's planned new wells. *See id*. at ¶ 19. Extraction also expressed its desire for a long-term relationship with its transportation company, and sought to form a joint venture as the best way to ensure this long-term relationship. *See id*. at ¶ 22.

15. At the time, Extraction owned and operated its own transportation company, XTR Midstream, LLC ("XTRM"). *See id.* at ¶ 21. [redacted]

16. Extraction also was interested in obtaining pipeline service to a large drilling project located west of Greeley, Colorado, near a community known as Triple Creek. *See id.* at ¶ 20. The project called for 22 wells, and was a significant opportunity for Extraction. *See id*. It also was the source of significant controversy among residents of Triple Creek, who opposed Extraction's plan to use tanker trucks. *See id*. Residents sued the Colorado Oil and Gas Conservation Commission (the "COGCC") after it approved Extraction's plan to use trucks, and a state court found the COGCC acted arbitrarily in approving Extraction's plans. *See* Order, *Neighbors Affected by Triple Creek v. COGCC*, 2016-cv-34274 (Denver Dist. Ct. Aug. 23, 2017), attached as Exhibit B. In particular, the court found Extraction repeatedly told residents and civic leaders that it would use pipelines. *See id.* at 6.

17. The PRM Transportation System was the solution to Extraction's transportation problems. *See* Exhibit A at ¶¶ 19-22; [redacted]. It was evident to ARB during negotiations that Extraction

needed pipelines for its wells in Triple Creek and the northern production area. *See* Exhibit A at ¶ 20. A committed pipeline would allow Extraction to drill new wells in a populated area and lessen community resistance. *See id.* at ¶¶19-20; *see also* Extraction Press Release "An Oil Pipeline Solution" (May 22, 2017), attached as Exhibit D. Extraction thus had no plans to build infrastructure to transport oil with trucks at each well site. *See* Exhibit A at ¶ 21.

18. For its part, PRM required a dedication of Extraction's interests in a defined area to justify entering the contract and investing in the installation and operation of the pipeline system. *See id.* at ¶ 23. Without receiving that dedication, which PRM intended to be part of Extraction's transportation agreement, it would not have installed the pipeline system. *See id*. In exchange for the dedication, Extraction wanted equity in the pipeline system with the potential to acquire the system later on, [redacted]. *See id.* at ¶¶ 23, 24(b); [redacted]

19. By agreeing to contract with PRM to provide transportation services, Extraction no longer needed to operate its own transportation company, XTRM. *See* Exhibit A at ¶ 22. [redacted].

20. Because Extraction would not have direct control over its transportation provider, Extraction insisted on creating a joint venture that would own PRM, providing Extraction with an equity stake in the transportation system and a voice in PRM's management. *See id*.

21. On April 14, 2017, the parties entered into four agreements:

First, ARB and XTRM entered into a First Amended and Restated Limited Liability Company Agreement (the "LLC Agreement"), and formed Platte River Holdings, LLC ("PRH"). *See* LLC Agreement, attached as Exhibit F. PRH would wholly own PRM, [redacted]

[redacted] The parties further agreed any business opportunities within the AMI would be shared between ARB and Extraction's affiliate. *See id.* at § 6.9(b). The LLC Agreement also limited the parties' ability to assign their interests in PRH. *See id.* at §§ 5, 10.

Second, Extraction and PRM agreed to the First Amended and Restated Transportation Services Agreement (the "PRM TSA"). *See* Exhibit A to Mot.

Third, XTRM and PRH entered into a Contribution Agreement whereby [redacted] *See* Contribution Agreement between ARB Platte River, LLC, XTR Midstream, LLC and Platte River Holdings, LLC (Apr. 14, 2017), attached as Exhibit G.

Fourth, [redacted]

22. The PRM TSA contemplated Extraction would dedicate its working interests in specific property to PRM for at least ten years (the "PRM Dedication Area"). *See id.* at § 4.1; *see also* Mot. at 3. [redacted] *See id.* at ¶ 24(b); *see also* Exhibit E. XTRM would not have received this grant of equity absent the dedication of Extraction's interests. *See id.*

23. Pursuant to the PRM TSA, [redacted] Exhibit A to Mot. at §§ 1.1(bb) (emphasis added), 2.1. The dedicated "Interests" also include all of Extraction's [redacted] *Id.*at § 1.1(bb) (emphasis added). The PRM Dedication Area includes certain locations in Larimer and Weld Counties, and was identified in the LLC Agreement. *See id.* at § 1.1(t); *see also* Exhibit F at § 10 [redacted]

24. The dedication was intended to cover, and drafted to cover, all of Extraction's crude oil interests in the ground within the PRM Dedication Area. *See* Exhibit A to Mot. at §§ 1.1(bb), 2.1; *see also* Exhibit A at ¶¶ 23, 24(b). Accordingly, the dedication identifies the real property interests burdened by the dedication. *See* Exhibit A to Mot. at § 1.1(t) (defining "Dedication Area" by legal description). After closing, [redacted]

25. To date, PRM has spent [redacted]

26. The PRM Transportation System is a custom system that is directly connected to each of Extraction's well pads within the PRM Dedication Area. *See* Exhibit A to Mot. at § 2.4. and Exh. B; *see also* Exhibit A at ¶ 26; [redacted] This requires

Extraction to prepare each well pad for connection to the pipeline, and for PRM to install well-specific connections at each well pad. *See* Exhibit A to Mot. at § 2.4. and Exh. B; *see also* Exhibit A at ¶ 26. In addition to the Assignment of Easements from XTRM, Extraction has executed right of way agreements for its additional well pads, which were granted in connection with, and in furtherance of, the PRM TSA and were recorded with the counties' records. *See* Exhibit A at ¶ 26; [redacted]

27. Because it committed to using the PRM Transportation System to transport its production, Extraction is limited in its ability to use alternative means to transport its crude oil within the PRM Dedication Area. [redacted]

28. The PRM TSA expressly states it [redacted] and restricts the assignment of the contract without the other party's consent. Exhibit A to Mot. at § 13.9.

DJ South Gathering and Its Transportation Agreement with Extraction

29. In October 2017, Extraction and ARB began negotiations on a new pipeline system to transport Extraction's crude oil produced from wells in five Colorado counties (the "DJ South Transportation System"). *See* Exhibit A at ¶ 29. Unlike the PRM Transportation System, which is directly connected to Extraction's wells, the DJ South Transportation System would connect to central facilities that collect production from multiple wells. *See id.* at ¶ 35. Because the new system was not directly connected to Extraction's well sites, it was important to ARB that the new contract expressly reflect the parties' intent to create a covenant running with the land. *See id.* at ¶ 36. Extraction did not disagree with this language. *See id.*

30. On January 17, 2018, ARB formed a new company, DJ South, to build and operate the new transportation system. *See id.* at ¶ 31. DJ South is wholly owned by PRH, which in turn was owned by ARB and Extraction's affiliate. *See id.*

31. On May 16, 2018, XTRM assigned all of its rights and interest under the LLC Agreement to Elevation Midstream, LLC ("Elevation"), pursuant to a Joinder and First Amendment to the LLC Agreement (the "LLC Amendment"). [redacted] At the time of the assignment, Elevation was a wholly owned subsidiary of Extraction.[3] *See* Extraction Press Release, announcing "South DJ Basin Midstream Solution" (July 9, 2018), attached as Exhibit O (identifying Elevation as a "wholly-owned subsidiary"). [redacted]

32. Also, on the same day, Extraction and DJ South entered into the Transportation Services Agreement dated May 16, 2018 (the "DJ South TSA"). *See* Exhibit B to Mot; [redacted] The PRM TSA and the DJ South TSA are together referred to as the "TSAs." [redacted] *See* Exhibit A at ¶ 33(a)-(b).

33. Pursuant to the DJ South TSA, Extraction [redacted]

[3] Beginning July 3, 2018, Elevation entered into a series of securities purchase agreements with GSO Capital Partners Lp. As a result, Extraction lost voting control of Elevation during the first quarter of 2020. *See* Extraction Oil & Gas, Inc., Quarterly Report (Form 10-Q) at 11 (May 11, 2020), attached as Exhibit AA.

[redacted] The DJ South Dedication Area is defined to include certain locations in five Colorado counties. *See id.* at § 1.1(u). As with the PRM TSA, DJ South would not have entered into the DJ South TSA without the dedication of Extraction's interests. *See* Exhibit A at ¶¶ 32, 33(b). In exchange for Extraction's dedication of all of its interests within the DJ South Dedication Area, [redacted]

34. The DJ South TSA contemplated that Extraction would dedicate its interests in the DJ South Dedication Area for at least ten years. *See* Exhibit B to Mot. at § 5.1; *see also* Mot. at 3. This intent was reflected in the additional equity Elevation (and Extraction) acquired in exchange for the dedication. *See* Exhibit A at ¶ 33(b); [redacted] Elevation (and Extraction) would not have received equity absent the dedication of its interests within the DJ South Dedication Area. *See* Exhibit A at ¶ 33(b).

35. To avoid any doubt as to the irrevocable nature of Extraction's commitment, the parties agreed that [redacted]

36. The DJ South dedication was intended to cover, and was drafted to cover, all of Extraction's crude oil interests in the ground within the DJ South Dedication Area. *See id.* at §§ 1.1(dd), [redacted] The dedication specifically identifies the real property

subject to the dedication. *See id.* at § 1.1(u) (defining Dedication Area by legal description). [redacted]

37. Extraction executed a "Memorandum of Dedication" that was recorded in the county real property records, as required by the DJ South TSA. *See* Exhibit B to Mot. at § 2.5 (requiring recording); *see also* Memoranda of Dedication, attached as Exhibit Q.

38. Further tying the dedication to Extraction's real property interests, the DJ South TSA restricts Extraction's ability to sell or transfer certain acreage within the DJ South Dedication Area without obtaining a release of that acreage from DJ South. *See* Exhibit B to Mot. at § 2.6.

39. [redacted] The PRM Transportation System and DJ South Transportation System are referred to together as the "Transportation Systems."

40. [redacted]

[redacted]

42. [redacted] Extraction is subject to an agreement with Broomfield that requires the use of pipelines to transport its production. *See* Resolution No. 2017-186, attached as Exhibit T. [redacted]

Compensation Under the TSAs

43. The Companies recover a portion of their upfront investments, along with a return on those investments, in several ways. First, Extraction is required to pay the Companies a monthly tariff approved by FERC for the volumes it delivers into the Transportation Systems. *See* Exhibit A to Mot. at § 5.1; Exhibit B to Mot. at § 6.1. Second, Extraction is obligated to make a fixed monthly payment to the Companies, regardless of the volumes it delivers. *See* Exhibit A to Mot. at § 6.1; Exhibit B to Mot. at § 7.1. The fixed monthly payment sets a minimum that the Companies will be paid, although it is offset, and usually exceeded, by tariff payments. *See* Exhibit A to Mot. at § 6.1; Exhibit B to Mot. at § 7.1. Third, the fixed monthly payment represents the monthly amount of the contractually defined "total financial commitment" that Extraction agreed to pay the Companies. *See* Exhibit A to Mot. at § 6.2; Exhibit B to Mot. at § 7.2.

44. [redacted]

45. The "total financial commitments" do not reflect the value of Extraction's commitment to transport all of its dedicated production using the Transportation Systems. *See* Mot. at 4-5; *see also* Exhibit A at ¶¶ 8-9, 40-43. The value of Extraction's dedications is much greater than the "total financial commitments," [redacted]

[redacted] The "total financial commitments" simply are intended to service and secure the debt financing associated with constructing the Transportation Systems, not to reflect their value to PRM and DJ South. *See* Exhibit A ¶¶ 8-9, 40-43.

LEGAL STANDARD

46. Summary judgment is inappropriate unless "the pleadings, the discovery and disclosure materials on file, and any affidavits show that there is no genuine issue as to any material fact and that the movant is entitled to judgment as a matter of law." *In re Maxus Energy Corp.*, 615 B.R. 62, 68 (Bankr. D. Del. 2020) (quoting *Celotex Corp. v. Catrett*, 477 U.S. 317, 322 (1986)). Extraction "bears the burden of proving that no genuine issue of material fact exists." *In re Quintas Corp.*, 397 B.R. 710, 714 (Bankr. D. Del. 2008) (citation omitted). The Companies' evidence is accepted as true, and all reasonable inferences are drawn in the Companies' favor and against summary judgment. *See In re LTC Holdings, Inc.*, 597 B.R. 554, 559 (Bankr. D. Del. 2019) (citing *Anderson v. Liberty Lobby, Inc.*, 477 U.S. 242, 255 (1986)).

ARGUMENT

47. Under Colorado law, only two elements are required to "create a real covenant, the parties must intend for the covenant to run with the land and bind successors in interest, and the covenant must 'touch and concern' the land." *Reishus*, 409 P.3d at 440 (citing *Cloud v. Ass'n of Owners*, 857 P.2d 435, 440 (Colo. App. 1992)).

48. These factors are different from those interpreted in *Sabine Oil & Gas Corp. v. HPIP Gonzales Holdings, LLC* (*In re Sabine Oil & Gas Corp.*), 550 B.R. 59 (Bankr. S.D.N.Y. 2016). In *Sabine*, the court held Texas law requires privity of estate and a conveyance of real property to create a covenant running with the land. *See id.* at 67-70. As discussed in Section III

below, privity and conveyance are not required under Colorado law, and in any event, the agreements at issue in *Sabine* are not the same as the TSAs here. *Sabine* has never been cited by a Colorado court on any issue, let alone whether contracts create covenants running with the land.

49. Under Colorado law, the factual record unquestionably could lead a "a reasonable jury… [to] return a verdict" for the Companies that the TSAs create covenants running with the land and bind Extraction's successors. *Anderson*, 477 U.S. at 248; *see Lookout*, 867 P.2d at 73-76 (considering facts surrounding creation of covenant under Colorado law). At a minimum, the complete factual record is required to determine whether the TSAs create covenants running with the land. *See Centennial-Aspen II Ltd. P'ship v. City of Aspen*, 852 F. Supp. 1486, 1492 (D. Colo. 1994). Extraction's Motion should be denied.

I. The Facts Demonstrate the Parties' Intent to Create Covenants Running With the Land Under Colorado Law.

50. To create a covenant running with the land, "the parties must intend for the covenant to run with the land and bind successors in interest." *Reishus*, 409 P.3d at 440. The parties' intent is determined by considering the agreements "as a whole, keeping in mind their underlying purpose." *B.B. & C. P'ship v. Edelweiss Condominium Ass'n*, 218 P.3d 310, 315 (Colo. 2009) (citation and internal quotations omitted); *see also Reishus*, 409 P.3d at 441 ("[W]e do not read individual provisions in isolation when deciding whether a covenant is real or personal; instead, we look at the covenant as a whole.").

51. Extraction concedes the DJ South TSA was intended to create a covenant running with the land burdening Extraction's real property interests in the DJ South Dedication Area. *See* Mot. at 6-7, 10-11; [redacted]

[redacted]. Intent, therefore, is established for the DJ South TSA. *See Monarch Midstream, LLC v. Badlands Prod. Co. (In re Badlands Energy, Inc.)*, 608 B.R. 854, 870 (Bankr. D. Colo. 2019) ("Under … Colorado law, an express statement in the document creating the covenant that the parties intend to create a covenant running with the land is usually dispositive of the intent issue.") (citations and internal quotations omitted); *see also Cloud*, 857 P.2d at 440 (express language demonstrated intent).

A. The PRM TSA Demonstrates Intent.

52. The PRM TSA also establishes a covenant running with the land burdening Extraction's interests in the PRM Dedication Area. *See Reishus*, 409 P.3d at 440. Extraction argues that the absence of express language in the PRM TSA evidences the parties' lack of intent. *See* Mot. at 11-12. As Extraction recognizes, however, "no magic words are necessary" to create a covenant running with the land. Mot. at 11; *see also TBI Expl. v. Belco Energy Corp.*, 2000 WL 960047, at *4 (5th Cir. June 14, 2000) ("Our survey of Colorado case law has not revealed any precedent …that a covenant running with the land must be expressed in specific or magical terms."). No Colorado court has required express language, or held the lack of express language is dispositive. Rather, Colorado courts look at contracts "as a whole…, giving effect to all provisions contained therein." *Lookout Mtn.*, 867 P.2d at 75 (citation omitted).

53. Under the PRM TSA, [redacted] Contrary to Extraction's contention, *see* Mot. at 4-6, 23-24, [redacted]

[redacted]

54. In *Badlands*, the court determined a covenant encompassed both extracted and unextracted minerals because it dedicated "the interest of Producer in all Gas reserves in and under" a specific geographic area. 608 B.R. at 869 (emphasis added). Contrary to Extraction's arguments, *see* Mot. at 4-6, 23-24, the PRM TSA's dedication similarly references and applies to Extraction's mineral interests "under" the ground, not only production from the wells. *See* Exhibit A to Mot. at §§ 1.1(bb), 2.1; *see also Bill Barrett Corp. v. Lembke*, 2018 WL 4225030, at *5 (Colo. App. Sept. 6, 2018) (real property includes non-extracted minerals) (citation omitted).

55. Underscoring its burden on real property, t[redacted]. This evidences the parties' intent to create a covenant running with the land. *See, e.g.*, *Alta Mesa Res., Inc. v. Kingfisher Midsteam, LLC (In re Alta Mesa Res., Inc.)*, 613 B.R. 90, 99-100 (Bankr. S.D. Tex. 2019) (covenant including "After-Acquired Interests" in the dedication ran with the land). The parties did not limit the dedication of interests to current production. *See, e.g.*, *Badlands*, 608 B.R. at 869 (contrasting dedication in *Sabine* that included only gas "produced and saved" from the area) (citing *Sabine*, 550 B.R. at 66).

56. The PRM TSA [redacted] Extraction's interests in its wells is derived from its leasehold mineral interests, *i.e.*, real property. *See Maralex Res., Inc. v. Chamberlain*, 320 P.3d 399, 403 (Colo. App. 2014)

("[A]n oil and gas lessee has an interest in real property"); *Hagood v. Heckers*, 513 P.2d 208, 214 (Colo. 1973) (a lessee's interest in oil and gas leases is real property). Extraction's dedication of its interests demonstrates its intent to create a covenant running with the land.

57. The PRM TSA also identifies the dedicated interests by a legal description of the real property, not simply by "production," as Extraction suggests. *See* Mot. at 17-18, 24. Specifically, the PRM Dedication Area is defined as four specific Townships in Larimer and Weld Counties. Exhibit A to Mot. at § 1.1(t). This is a legal description of real property, not production. *See Griffin v. United Bank of Denver*, 599 P.2d 866, 868 (Colo. 1979) ("[A] complete legal description of real estate constitutes a clear and accurate identification of the property.") (citations omitted); *see also Badlands*, 608 B.R. at 869 (contrasting dedication in *Sabine* that was limited to gas "produced and saved … from wells … located within the Dedicated Area") (quoting *In re Sabine Oil & Gas Corp.*, 567 B.R. 869, 872 (S.D.N.Y. 2017)) (emphasis added).

58. To avoid any doubt about the continuing nature of the PRM TSA, Section 13.9 expressly provides *all* of the agreement [redacted]. The parties also [redacted] *Id.*; *see also Badlands*, 608 B.R. at 870 (restriction on assignment was suggestive of intent to bind successors and assigns).

59. The LLC Agreement between ARB and Extraction's affiliate underscores the parties' intent. PRH was formed expressly to own, operate, develop, and expand PRM's crude oil gathering facilities and related infrastructure. *See* Exhibit F at § 1.6. Extraction's affiliate and ARB agreed that they would share any business opportunity within the geographic area defined by the LLC Agreement. *See id.* at § 6.9(b). The agreement also restricted ARB and XTRM from

assigning their interests in PRH absent certain conditions. *See id.* at § 5.1. These restrictions on assignment were the demands of Extraction, which wanted express contractual assurances it could control the identity of the party installing and operating the PRM Transportation System. *See* Exhibit A at ¶ 28. Extraction cannot now avoid its intent to bind successors and assigns.

60. The express provisions in the PRM TSA demonstrate both parties' intent to create a covenant running with the land, and they must be read as a whole. In *Cloud*, the Colorado Court of Appeals determined a covenant ran with the land by reading the agreement's provisions as a whole, not in isolation. *See* 857 P.2d at 440; *see also Reishus*, 409 P.3d at 441 ("[W]e do not read individual provisions in isolation when deciding whether a covenant is real or personal; instead, we look at the covenant as a whole."). The PRM TSA must be interpreted the same way.

B. The Purpose and Surrounding Circumstances of the PRM TSA Demonstrate the Parties' Intent to Create a Covenant Running With the Land.

61. Under Colorado law, courts consider whether the parties intended to create a covenant running with the land based on the contract's purpose. *See Reishus*, 409 P.3d at 435. In *Reishus*, for example, the court found an ownership agreement ran with the land where its purpose was "to have an agricultural property that would also provide a quality hunting experience." *Id.* at 441 (citations and internal quotations omitted). The PRM TSA reveals the same purpose to create a covenant running with the land.

62. [redacted]

Residents complained about Extraction's use of trucks to transport production, and sued the COGCC for allowing Extraction to move forward with drilling in Triple Creek without a pipeline commitment. *See* Exhibit B. A state court observed that Extraction's use of trucks conflicted with its assurances to city officials and residents that it would use pipelines. *See id.* [redacted]

[redacted]

[redacted] After entering into the PRM TSA, Extraction issued a press release touting the PRM Transportation System as "a dedicated oil pipeline would be used to transport oil produced at Triple Creek." Exhibit D (emphasis added). [redacted]

[redacted]. Its intent to create a covenant tied to the land, therefore, is clear from its indisputable conduct. *See Reishus*, 409 P.3d at 435-41.

64. PRM, in turn, had a clear purpose of securing a covenant running with the land when entering the PRM TSA. Specifically, PRM required a dedication of Extraction's interests in a defined area in order to justify entering the contract and investing in the installation and operation of the pipeline system. *See* Exhibit A at ¶ 23. Without receiving that dedication, which PRM intended to be part of Extraction's transportation agreement, it would not have installed the pipeline system. *See id.* This is not unusual in the industry, because the dedication assures the midstream company it will obtain financing to build the system. *See id.* at ¶¶ 10, 12.

65. ARB issued a press release corroborating its purpose, stating it had secured a dedication from Extraction for all "existing and all future wells." ARB Press Release, announcing

"Large Production Dedication in Colorado's Niobrara Play" (July 13, 2007), attached as Exhibit Y. PRM constructed 95 miles of pipeline to transport Extraction's production downstream. *See* Exhibit A at ¶ 25. The PRM Transportation System is custom built, and physically connected to each well pad on Extraction's leasehold. *See id.* at ¶ 26; [redacted]

66. The parties' intent to create a covenant that would bind their successors and assigns, is demonstrated by their purpose in entering into the PRM TSA. *See Reishus*, 409 P.3d at 435 (determining covenant ran with the land based on purpose of the parties); *Lookout Mtn.*, 867 P.2d at 75 (construing covenants "as a whole" and "in view of their underlying purposes").

67. The facts also explain why the PRM TSA does *not* expressly state that it creates a covenant running with the land. Unlike the PRM Transportation System, which is directly connected to Extraction's wells on its leaseholds, the DJ South Transportation System receives Extraction's crude oil through CGFs located away from Extraction's wells. Because the DJ South Transportation System was configured differently, [redacted]

68. At a minimum, the foregoing facts demonstrate the PRM TSA can be found to be "ambiguous," that is, "reasonably susceptible to more than one meaning." *Cheyenne Mtn. Sch Dist. No. 12*, 861 P.2d at 715 ("Silence does create ambiguity … when it involves a matter naturally within the scope of the contract."). The Court must consider all facts surrounding the contract's formation and performance to ascertain intent. *See Centennial-Aspen II Ltd. P'ship*, 852 F. Supp.

at 1492. Given the facts set forth above, "a reasonable jury" could "return a verdict" for the Companies that the PRM TSA was intended to create a covenant running with the land. *Anderson*, 477 U.S. at 248. Summary judgment should be denied.

II. The TSAs Touch and Concern the Land.

69. Under Colorado law, "[a] covenant touches and concerns the land if it 'closely relates to the land, its use, or its enjoyment.'" *Reishus*, 409 P.3d at 440 (quoting *Cloud*, 857 P.2d at 440). The "'touch and concern' requirement is fulfilled when the covenant operates to benefit the physical use of the land." *Bigelow v. Nottingham*, 833 P.2d 764 (Colo. App. 1991), *rev'd in part on other grounds*, *Haberl v. Bigelow*, 855 P.2d 1368 (Colo. 1993); *see also Lookout Mtn.*, 867 P.2d at 75 (holding building restriction created covenant running with the land where benefits and burdens were closely related to property's use and enjoyment). Whether a covenant closely relates to the land must be "viewed in the context of [the agreement's] purpose." *Badlands*, 608 B.R. at 868 (contract must "be of such character that its performance or nonperformance will so affect the use, value or enjoyment of the land itself"). This is an inherently factual analysis.

70. Applying a similar principle, the court in *Alta Mesa* held natural gas gathering agreements contained covenants running with the land, because they furthered the purpose of the producer's mineral leases. 613 B.R. at 96, 102. "[A]n oil and gas lease creates an interest in land to search for and reduce to possession such [oil] as might be found beneath the land," and therefore "[a]ll of the property interests associated with an oil and gas lease," including the interests for production and marketing "are necessary for the lessee to successfully explore and produce his reserves." *Id.* at 102-03 (citation and internal quotations omitted). Not only did the gathering systems enhance the value of produced natural gas, but they enhanced the producer's unproduced reserves by reducing transportation costs for future production. *Id.* at 103-04.

71. Similarly, in *Badlands*, the court determined a production dedication touched and concerned the land under Utah law. 608 B.R. at 869. The court explained because the "dedicated reserves" under the gathering agreement were defined broadly to include "the interest of Producer in all Gas reserves in and under" the dedicated area, the gathering agreement encompassed real property. *Id.* (emphasis in original). As in Utah, "real property" under Colorado law includes non-extracted minerals. *See Bill Barrett Corp.*, 2018 WL 4225030, at *5 (citation omitted).

72. The TSAs touch and concern Extraction's real property interests because they directly benefit, and burden, Extraction's interests within the Dedication Areas. Extraction's mineral interests benefit from the Companies' obligation to construct permanent underground pipeline systems and related infrastructure capable of transporting Extraction's crude oil produced from the Dedication Areas. *See* Exhibit A to Mot. at §§ 1.1(nn), 2.4 and Exh. A; Exhibit B to Mot. at §§ 3.1. This provides direct, immediate value to Extraction's mineral estate by ensuring its production can access downstream markets. *See Alta Mesa*, 613 B.R. at 103-04 (benefit of dedicated transportation created covenant running with the land); *see also* Exhibit A at ¶ 13.

73. The TSAs particularly benefit Extraction's drilling program in urban areas near Denver. [redacted]

[redacted] This limits Extraction's "right to determine what happens to the [dedicated Interests] once it drills." *Alta Mesa*, 613 B.R. at 104. Extraction "commit[ed] itself to the gathering agreements," and "gave up its right to pursue other gathering strategies." *Id*.

75. The TSAs also restrict Extraction's use of real property. To connect its wells to the PRM Transportation System, Extraction granted easements to PRM to access the leasehold. *See* Exhibit A at ¶¶ 24(d), 26; *see also* Exhibits H, L. These agreements "carve out a portion of [Extraction's] lease easements and grant those portions to [the Companies]." *Alta Mesa*, 613 B.R. at 104.

76. Under the DJ South TSA, Extraction cannot transfer certain acreage within the DJ South Dedication Area without first obtaining DJ South's release. *See* Exhibit B to Mot. at § 2.6. This closely relates to Extraction's "land, its use, or its enjoyment." *Cloud*, 857 P.2d at 440. The DJ South TSA also required Extraction to execute Memoranda of Dedication, which were recorded in the county real property records. *See* Exhibit B to Mot at § 2.5; *see also* Exhibit Q. These Memoranda reaffirm that the DJ South TSA affects and closely relates to Extraction's real property interests. *See* C.R.S. § 38-35-108 (recording necessary to put successors and assigns on notice).

77. The TSAs do much more than "affect only personal property," as Extraction contends. Mot. at 24. Rather, the TSAs are closely related to Extraction's use, possession, and enjoyment of real property, and thus touch and concern the land. *See Reishus*, 409 P.3d at 441; *see also Alta Mesa*, 613 B.R. at 104. Extraction's Motion should be denied.

III. Extraction's Attempt to Add New Legal Factors to Colorado Law Is Unavailing.

78. Faced with unfavorable facts on the two applicable elements of Colorado law, Extraction tries to impose additional, *inapplicable* legal requirements. *First*, Extraction argues it

can somehow satisfy its obligations with money damages, and therefore the TSAs do not touch and concern the land. *See* Mot. at 24-25. *Second*, Extraction claims a covenant running with the land requires a specific "legal relationship" akin to a formal conveyance. *See id.* at 21-22. *Third*, Extraction asserts horizontal privity is necessary to create a covenant running with the land. *See id.* at 13-20. As explained below, Extraction is wrong on all counts.

A. The "Total Financial Commitments" Do Not Eliminate the TSA's Covenants.

79. Both TSAs require Extraction to pay a "total financial commitment" over their terms. *See* Exhibit A to Mot. at §§ 1.1(ccc), 3.1; Exhibit B to Mot. at §§ 1.1(kkk), 4.1. [redacted]

80. Extraction argues that, because it can pay the remainder of the "total financial commitments" (notwithstanding its insolvency), the TSAs do not touch and concern the land. *See* Mot. at 24-25. Extraction cites no relevant Colorado authority to support this argument. *See id.*

81. *Badlands* considered a similar argument. *See* 608 B.R. at 868. There, the producer argued its gathering agreement created only a personal covenant, and did not burden real property, because it could pay the gatherer a deficiency payment in lieu of delivering gas. *See id.* Rejecting this argument, the court explained the payment was meant "to compensate [the gathering company] for the burdens associated with acquiring and operating the [gathering system]," but had no effect on the dedication or its covenant. *Id.* The same legal principle applies here, since payment of money cannot be divorced from the benefit to the mineral estate as a whole. *See, e.g.*, *Cloud*, 857 P.2d at 440 (covenant granting 10 percent of gross receipts as payment to developer ran with the land where remaining 90 percent benefitted homeowner association).

82. Extraction's argument concerning the "total financial commitments" is factually misplaced. The "total financial commitments" are not liquidated damages, and are simply one of several available remedies under the TSAs. *See* Exhibit A to Mot. at § 11.3; Exhibit B to Mot. at § 12.3. Nor are they intended to reflect the value of Extraction's dedications, which are much greater than the "total financial commitments." *See* Exhibit A at ¶¶ 8-9, 40-43. The purpose of the "total financial commitments" is to service the debt to build an in-field gathering system, not to monetize the dedications, and reflect only a percentage of projected total revenue. *See id.*; *see also* Exhibits P, U. Extraction's argument should be rejected. *See Badlands*, 608 B.R. at 868.

B. Colorado Law Does Not Impose a "Legal Relationship" Test.

83. Extraction also urges the Court to consider whether the covenants created by the TSAs affect Extraction's "legal relationship to the land itself." Mot. at 21. Extraction claims this test is not satisfied, because produced crude oil is personal property, and the covenants do not affect Extraction's use of or legal right to the land. *See id.* at 21, 26-27.

84. Extraction's only support for the "legal relationship" test is a law review article written in 1914 by Harry Bigelow. *See* Mot. at 21 (citing Harry Bigelow, *The Content of Covenants in Leases*, 12 Mich. L. Rev. 639, 652 (1914)). While Extraction claims Colorado courts have "repeatedly cited Dean Bigelow's work with approval," *see* Mot. at 21 n.11, the "work" Extraction refers to is the Restatement (First) of Property, to which Dean Bigelow was a contributor. *See id.* No Colorado case relies upon, or even cites, Bigelow's 1914 article.

85. None of the cases cited by Extraction applies this "legal relationship" test. Mot. at 21-22 (collecting cases). Instead, each case considered the two elements—and only the two elements—required under Colorado law. *See Reishus*, 409 P.3d at 440 (covenant touched and concerned land where purpose was to have an agricultural property with quality hunting and included use restrictions); *Lookout Mtn.*, 867 P.2d at 75 (covenant touched and concerned land

because it was imposed for the benefit of the subdivision as a whole by protecting property values and ensuring a general plan of construction); *Cloud*, 857 P.2d at 440-41 (covenant for division of gross receipts from use of guest rooms touched and concerned the land because it benefitted owners); *Bigelow*, 833 P.2d at 767 (subordination rider did not touch and concern land where parties' entitlement to use of land was not increased and no improvements were made).

86. Even if the Court applied Bigelow's "legal relationship" test, the TSAs easily satisfy it. This test "turns on whether a covenant materially affects the promisor's legal relationship to the land itself, as measured by whether the covenant makes the estate more or less valuable." Bigelow, *supra*, at 652 (emphasis added). Additionally, the covenant must "operate primarily to benefit the covenantee … in the exercise of his privilege as owner of the soil." *Id.*

87. As discussed above, the TSAs significantly increase the value of Extraction's mineral estate, and benefit any subsequent producer in the Dedication Areas, not simply Extraction as the owner of chattel. *See supra* Sec. II, ¶¶ 72-73; *see also Alta Mesa*, 613 B.R. at 103-04.

88. Extraction's title to the crude oil is irrelevant. *Contra* Mot. at 4, 16, 20, 24. In *Southwest Pipe Line Co. v. Empire Natural Gas Co.*, the court rejected a similar argument under Oklahoma law, holding title was irrelevant, as the agreement created an easement for the buyer to build gathering pipelines on the leasehold, constituting an interest in the land. 33 F.2d 248, 249-50 (8th Cir. 1929). Colorado law is in accord. *See Universal Res. Corp. v. Ledford*, 961 P.2d 593, 595 (Colo. App. 1998) (free use clause created real covenant even though estate owner had no title to production). The TSAs benefit and burden Extraction's interests in the Dedication Areas, thus touch and concern the land. *See supra* sec II, ¶¶ 72-76; *see also Cloud*, 857 P.2d at 440.

C. Horizontal Privity Is Not Required to Create a Covenant in Colorado.

89. Extraction argues Colorado law requires privity of estate, or horizontal privity, between the parties to create a covenant running with the land. *See* Mot. at 13-20. This is incorrect.

90. Extraction primarily cites two Colorado Supreme Court cases decided in 1907 and 1954. Contrary to Extraction's argument, although both *Farmers' High Line Canal & Reservoir Co. v. New Hampshire Real Estate Co.*, 92 P. 290 (Colo. 1907), and *Taylor v. Melton*, 274 P.2d 977 (Colo. 1954), reference the concept of "privity of estate" both cases actually focused on vertical privity. For example, *Farmers'* concerned whether a written agreement by a canal owner to furnish water created a covenant that bound the current canal owner. *See* 92 P. at 293. Similarly, in *Taylor*, the issue was whether the defendant was bound by a restriction that was not in the defendant's deed, and was only in the deed of his predecessor in title. *See* 247 P.2d at 981-82. No Colorado court has referenced the concept of privity of estate or horizontal privity since 1954.

91. The year after *Taylor* was decided, the Colorado Supreme Court held a restrictive covenant ran with the land, even though it was never in the defendant's chain of title, and that it could be enforced even between parties that had no direct contractual relations. *See Pagel v. Gisi*, 286 P.2d 636, 638-39 (Colo. 1955). Privity was unnecessary to create the covenant. *See id.*

92. Every subsequent Colorado decision regarding covenants running with the land—including the cases cited by Extraction—has expressly stated the only requirements to create a real covenant are (1) the parties' intent, and (2) the covenant touches and concerns the land. *See*, *e.g.*, *Reishus*, 409 P.3d at 440 (containing no reference to horizontal privity requirement); *DeJean v. Grosz*, 412 P.3d 733, 739 (Colo. App. 2015) (same); *In re Banning Lewis Ranch Co.*, 532 B.R. 335, 345 n.11 (Bankr. D. Co. 2015) (same); *MidCities Metro. Dist. No. 1. v. U.S. Bank Nat'l Ass'n*, 2013 WL 3200088, at *3 (D. Colo. June 24, 2013) (same); *Lookout Mtn.*, 867 P.2d at 74 (same); *Cloud*, 857 P.2d at 440 (same); *Bigelow*, 833 P.2d at 767-68 (same).

93. The Fifth Circuit reached the same conclusion after conducting a "survey of Colorado case law." *TBI Expl.*, 2000 WL 960047, at *4 (only elements required under Colorado

law are "intent by the parties to the covenant that the covenant runs with the land" and "the covenant must 'touch and concern' the land.") (collecting cases). Modern Colorado courts do not recognize a privity requirement. *See, e.g.*, *Reishus*, 409 P.3d at 435-441 (finding amended ownership agreement created covenant running with the land even though there was no conveyance of any real property interest); *see also* Restatement (Third) Property § 2.4 (2000) (the horizontal privity requirement is no longer needed to ensure covenants will be recorded because "[i]n modern law, the Statute of Frauds and recording acts perform that function").

94. Extraction's reliance on C.R.S. § 38-30-121 also is misplaced. The statute simply provides that when a deed concerning real property is conveyed, the foregoing covenants run with the land. *See* C.R.S. § 38-30-121. It does not state that a conveyance of real property is necessary to create a covenant. Nothing in the statute disturbs Colorado's common law requirements on covenants running with the land, and no Colorado court has held otherwise.

95. Even if horizontal privity is required under Colorado law, and it is not, it has been satisfied. [redacted] This was a conveyance of real property to PRM. *See Badlands*, 608 B.R. at 874 (horizontal privity satisfied through simultaneous asset transfer).

96. Extraction argues even if a property right was granted to the Companies, it would not satisfy horizontal privity, because such property right would not flow from Extraction's mineral interests. *See* Mot. at 16 (citing *In re Sabine Oil & Gas Corp.*, 734 F. App'x 64, 67 (2d

Cir. 2018)). In *Badlands*, the court rejected a similar argument, explaining, "unlike in *Sabine*, the covenants burden Producers' real property interests (the Dedicated Reserves and the Producers' interests in the Leases) in the context of a simultaneous conveyance of real property interests (the Gas Gathering and Saltwater Disposal Systems) to [the midstream company], both of which are located in the same geographic area (the [Area of Mutual Interest])." 608 B.R. at 874.

97. [redacted] *See Booker v. Chreokee Water Dist.*, 651 P.2d 452, 453-54 (Colo. App. 1982) (a contractual license becomes a property right when coupled with an interest); *see also Private Right of Way*, BLACK'S LAW DICTIONARY (11th ed. 2019) (defining "private right of way" as an easement); Jon W. Bruce & James W. Ely, Jr., *The Law of Easements & Licenses in Land* § 11:8 (June 2020) ("A license may be coupled with an interest when the licensee owns personal property on the servient land related to the purpose of the license.") (collecting cases).

99. While horizontal privity is not required under Colorado law, the facts demonstrate that horizontal privity exists between the Companies and Extraction in connection with the TSAs.

100. The Companies reserve their rights in all respects to supplement this Response at or prior to the hearing on the Motion.

CONCLUSION

For the reasons set forth above, Extraction's Motion should be denied.

Dated: September 18, 2020
Wilmington, Delaware

/s/ Curtis S. Milller

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CERTIFICATE OF SERVICE

I, Brett S. Turlington, certify that I am not less than 18 years of age, and that service of the foregoing *Platte River Midstream, LLC and DJ South Gathering, LLC's Response in Opposition to Extraction Oil & Gas, Inc.'s Motion for Summary Judgment* was caused to be made on September 18, 2020, in the manner indicated upon the entities identified below.

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/s/ Brett S. Turlington
Brett S. Turlington (No. 6705)

EXHIBIT J

UNITED STATES BANKRUPTCY COURT
DISTRICT OF DELAWARE

IN RE:	Chapter 11
	Case No. 20-11548 (CSS)
EXTRACTION OIL & GAS, INC., *et al.*,	(Jointly Administered)
	Courtroom 6
	824 Market Street
Debtors.	Wilmington, Delaware 19801
	Tuesday, October 20, 2020
	10:01 a.m.

TRANSCRIPT OF HYBRID TELEPHONIC/ZOOM HEARING
BEFORE THE HONORABLE CHRISTOPHER S. SONTCHI
CHIEF UNITED STATES BANKRUPTCY JUDGE

APPEARANCES:

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Proceedings recorded by electronic sound recording: transcript produced by transcription service.

interest or non-operated working interest goes -- comes to that $93,000 a day.

Q And so taking that amount out, on a per day basis for oil, what did ARB compute would be the value of Extraction's remaining share of the oil produced from the DJ South system?

A Again, based on the average over the next six months, Extraction's share is approximately $218,000 per day.

Q And then looking at the 309180, is that just taking that number and multiplying it by those days?

A Yes, that's correct.

Q And so, if the wells connected to the DJ South system were shut in for 180 days, what did the ARB determine would be the financial cost to Extraction?

A Specific to the crude oil, a little over $39 million is what we estimated.

Q Now the second half, the bottom half of your demonstrative here, has -- is titled, Natural Gas to Badger CGF. Do you see that?

A Yes.

Q Why did you calculate a value of natural gas that would be -- well, let me just ask it that way.

Why did you calculate a financial cost of natural gas?

A Because it's not possible to shut in solely the oil production from the well. In the event that a well is shut in, you would lose both oil and any associated gas

production.

Q How did you derive a value of natural gas production associated with wells connected to the Badger CGF?

A In this case, we looked at recent Extraction 10Q filings to look at the ratio of Extraction revenue between crude oil and natural gas. And it's approximately a 60/40 split, 60 percent oil revenue, 40 percent natural gas. So we used that ratio to essentially estimate the value of the gas from these wells.

Q And if these wells were shut in for that same 180 days that we discussed previously, how much did ARB estimate would be the value of Extraction's share of natural gas that would be shut in for wells connected to the Badger CGF?

A Based on our estimates, we estimate it to be a little over 26 million over six months.

Q Did ARB perform a similar analysis for the cost of shutting in production for wells connected to the Platte River system?

A Yes, we did.

Q If we could flip to the second page of this demonstrative deck, does this page, Mr. McGillis, reflect ARB's calculation of those similar values associated with the Platte River system?

A Yes, it does.

Q Did you conduct it in the same way that we just went

through in the DJ South system?

A Yes, that's correct.

Q Let me start by asking you where the volumes come from that you identified for -- that's identified on here as wells without trucking, 12,624 barrels a day. What does that mean?

A So in this case, again per Extraction's oil transition plan, they've identified well pads that would be unable or cannot provide trucking upon -- and to the extent that they cannot have trucks remove the oil from the site, we went through and added those up based on the production provided by Extraction, and that comes to approximately 12,600 barrels per day.

Q And based on the same analysis of the value of oil and natural gas associated with those wells, what did ARB compute would be the financial cost of shutting in production for 180 days?

A In this case, we estimated it to be a little over 85 million.

Q And so adding that to the same amount for the same period for the DJ South wells, what is the total amount of the financial cost?

A The total we estimated to be approximately 150 million over six months.

MR. CHRISMAN: Your Honor, if I could just have one minute to check my notes. Your Honor, I don't have any

EXHIBIT K

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2020

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____ to _____

Commission file number 001-37907

EXTRACTION OIL & GAS, INC.

(Exact name of registrant as specified in its charter)

Delaware	**46-1473923**
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
370 17th Street **Suite 5300** **Denver, Colorado**	**80202**
(Address of principal executive offices)	

(720) 557-8300

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of exchange on which registered
Common Stock, par value $0.01	**XOG**	**NASDAQ Global Select Market**

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☒ No ☐

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company or an emerging growth company. See the definitions of "large accelerated filer", "accelerated filer", "smaller

reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	☐	Accelerated Filer	☒
Non-Accelerated Filer	☐	Smaller Reporting Company	☐
		Emerging Growth Company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ☐ No ☒

The total number of shares of common stock, par value $0.01 per share, outstanding as of May 8, 2020 was 138,135,046.

EXTRACTION OIL & GAS, INC.
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PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)
(Unaudited)

	March 31, 2020	December 31, 2019
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 31,993	$ 32,382
Accounts receivable		
Trade	49,878	32,009
Oil, natural gas and NGL sales	38,850	105,103
Inventory, prepaid expenses and other	34,494	36,702
Commodity derivative asset	164,330	17,554
Total Current Assets	319,545	223,750
Property and Equipment (successful efforts method), at cost:		
Proved oil and gas properties	4,676,967	4,530,934
Unproved oil and gas properties	417,021	524,214
Wells in progress	154,981	149,733
Less: accumulated depletion, depreciation, amortization and impairment charges	(3,057,098)	(2,985,983)
Net oil and gas properties	2,191,871	2,218,898
Gathering systems and facilities, net of accumulated depreciation	—	315,777
Other property and equipment, net of accumulated depreciation	72,589	72,542
Net Property and Equipment	2,264,460	2,607,217
Non-Current Assets:		
Commodity derivative asset	88,783	13,229
Other non-current assets	30,600	82,761
Total Non-Current Assets	119,383	95,990
Total Assets	$ 2,703,388	$ 2,926,957
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 163,057	$ 190,864
Accounts payable and accrued liabilities, related party	46,777	—
Revenue payable	104,702	108,493
Production taxes payable	115,556	115,489
Commodity derivative liability	716	1,998
Accrued interest payable	18,042	20,625
Asset retirement obligations	15,328	27,058
Total Current Liabilities	464,178	464,527
Non-Current Liabilities:		
Credit facility	470,000	470,000
Senior Notes, net of unamortized debt issuance costs	1,086,347	1,085,777
Production taxes payable	119,675	98,740
Commodity derivative liability	—	108
Other non-current liabilities	59,689	54,579
Asset retirement obligations	78,445	68,850
Deferred tax liability	2,200	—
Total Non-Current Liabilities	1,816,356	1,778,054
Total Liabilities	2,280,534	2,242,581
Commitments and Contingencies—Note 13		
Series A Convertible Preferred Stock, $0.01 par value; 50,000,000 shares authorized, 185,280 issued and outstanding	182,157	175,639
Stockholders' Equity:		
Common stock, $0.01 par value; 900,000,000 share authorized; 137,891,740 and 137,657,922 issued and outstanding, respectively	1,336	1,336
Treasury stock, at cost, 38,859,078 shares	(170,138)	(170,138)
Additional paid-in capital	2,143,670	2,156,383
Accumulated deficit	(1,734,171)	(1,743,208)
Total Extraction Oil & Gas, Inc. Stockholders' Equity	240,697	244,373
Noncontrolling interest	—	264,364
Total Stockholders' Equity	240,697	508,737
Total Liabilities and Stockholders' Equity	$ 2,703,388	$ 2,926,957

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)
(Unaudited)

	For the Three Months Ended March 31,	
	2020	**2019**
Revenues:		
Oil sales	$ 124,219	$ 165,424
Natural gas sales	22,302	35,892
NGL sales	17,193	20,601
Gathering and compression	1,473	—
Total Revenues	165,187	221,917
Operating Expenses:		
Lease operating expense	30,390	21,857
Midstream operating expenses	3,935	—
Transportation and gathering	22,786	10,365
Production taxes	13,454	18,129
Exploration and abandonment expenses	112,480	6,194
Depletion, depreciation, amortization and accretion	76,051	118,770
Impairment of long lived assets	775	8,248
Gain on sale of property and equipment	—	(222)
General and administrative expense	10,596	27,652
Other operating expenses	52,575	—
Total Operating Expenses	323,042	210,993
Operating Income (Loss)	(157,855)	10,924
Other Income (Expense):		
Commodity derivative gain (loss)	263,015	(122,091)
Loss on deconsolidation of Elevation Midstream, LLC	(73,139)	—
Interest expense	(21,358)	(13,008)
Other income	574	1,143
Total Other Income (Expense)	169,092	(133,956)
Income (Loss) Before Income Taxes	11,237	(123,032)
Income tax (expense) benefit	(2,200)	29,000
Net Income (Loss)	$ 9,037	$ (94,032)
Net income attributable to noncontrolling interest	6,160	3,975
Net Income (Loss) Attributable to Extraction Oil & Gas, Inc.	2,877	(98,007)
Adjustments to reflect Series A Preferred Stock dividends and accretion of discount	(6,518)	(4,317)
Net Loss Available to Common Shareholders, Basic and Diluted	$ (3,641)	$ (102,324)
Loss Per Common Share (Note 12)		
Basic and diluted	$ (0.03)	$ (0.60)
Weighted Average Common Shares Outstanding		
Basic and diluted	137,726	170,702

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Table of Contents

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)
(Unaudited)

	For the Three Months Ended March 31,	
	2020	2019
Cash flows from operating activities:		
Net income (loss)	$ 9,037	$ (94,032)
Reconciliation of net income (loss) to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	76,051	118,770
Abandonment and impairment of unproved properties	106,928	3,893
Impairment of long lived assets	775	8,248
Gain on sale of property and equipment	—	(222)
Gain on repurchase of 2026 Senior Notes	—	(7,317)
Amortization of debt issuance costs	1,242	1,498
Non-cash lease expense	4,871	2,486
Contract asset	8,465	—
Commodity derivatives (gain) loss	(263,015)	122,091
Settlements on commodity derivatives	24,932	(3,538)
Earnings in unconsolidated subsidiaries	(480)	(338)
Loss on deconsolidation of Elevation Midstream, LLC	73,139	—
Distributions from unconsolidated subsidiaries	—	1,751
Deferred income tax expense (benefit)	2,200	(29,000)
Stock-based compensation	—	13,008
Changes in current assets and liabilities:		
Accounts receivable—trade	(9,127)	11,908
Accounts receivable—oil, natural gas and NGL sales	66,253	2,981
Inventory, prepaid expenses and other	584	136
Accounts payable and accrued liabilities	(7,699)	(10,638)
Accounts payable and accrued liabilities, related party	46,777	—
Revenue payable	(1,690)	(21,506)
Production taxes payable	21,002	22,919
Accrued interest payable	(2,583)	(4,429)
Asset retirement expenditures	(10,563)	(4,558)
Net cash provided by operating activities	147,099	134,111
Cash flows from investing activities:		
Oil and gas property additions	(143,000)	(188,027)
Sale of property and equipment	12,117	16,521
Gathering systems and facilities additions, net of cost reimbursements	4,193	(49,175)
Other property and equipment additions	(2,980)	(8,213)
Investment in unconsolidated subsidiaries	(10,033)	(4,929)
Distributions from unconsolidated subsidiary, return of capital	—	1,448
Net cash used in investing activities	(139,703)	(232,375)
Cash flows from financing activities:		
Borrowings under credit facility	70,000	65,000
Repayments under credit facility	(70,000)	(25,000)
Repurchase of 2026 Senior Notes	—	(28,460)
Repurchase of common stock	—	(32,212)
Payment of employee payroll withholding taxes	(35)	(454)
Dividends on Series A Preferred Stock	—	(2,721)
Debt and equity issuance costs	(22)	(94)
Preferred Unit issuance costs	—	(10)
Net cash used in financing activities	(57)	(23,951)
Effect of deconsolidation of Elevation Midstream, LLC	(7,728)	—
Decrease in cash and cash equivalents	(389)	(122,215)
Cash, cash equivalents at beginning of period	32,382	234,986
Cash, cash equivalents at end of the period	$ 31,993	$ 112,771
Supplemental cash flow information:		
Property and equipment included in accounts payable and accrued liabilities	$ 99,602	$ 143,168
Cash paid for interest	$ 24,865	$ 25,265
Accretion of beneficial conversion feature of Series A Preferred Stock	$ 1,770	$ 1,596
Preferred Units commitment fees and dividends paid-in-kind	$ 6,160	$ 3,975
Series A Preferred Stock dividends paid-in-kind	$ 4,748	$ —

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY AND NONCONTROLLING INTEREST
(In thousands)
(Unaudited)

	Common Stock		Treasury Stock		Additional Paid in Capital	Accumulated Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2020	176,517	$ 1,336	38,859	$ (170,138)	$ 2,156,383	$ (1,743,208)	$ 244,373	$ 264,364	$ 508,737
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(6,160)	—	(6,160)	6,160	—
Series A Preferred Stock dividends	—	—	—	—	(4,748)	—	(4,748)	—	(4,748)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,770)	—	(1,770)	—	(1,770)
Restricted stock issued, net of tax withholdings and other	234	—	—	—	(35)	—	(35)	—	(35)
Net income	—	—	—	—	—	9,037	9,037	—	9,037
Effects of deconsolidation of Elevation Midstream, LLC	—	—	—	—	—	—	—	(270,524)	(270,524)
Balance at March 31, 2020	176,751	$ 1,336	38,859	$ (170,138)	$ 2,143,670	$ (1,734,171)	$ 240,697	$ —	$ 240,697

	Common Stock		Treasury Stock		Additional Paid in Capital	Accumulated Deficit	Extraction Oil & Gas, Inc. Stockholders' Equity	Noncontrolling Interest	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				Amount	
Balance at January 1, 2019	176,210	$ 1,678	4,543	$ (32,737)	$ 2,153,661	$ (375,788)	$ 1,746,814	$ 147,872	$ 1,894,686
Preferred Units issuance costs	—	—	—	—	—	—	—	(10)	(10)
Preferred Units commitment fees & dividends paid-in-kind	—	—	—	—	(3,975)	—	(3,975)	3,975	—
Stock-based compensation	—	—	—	—	13,008	—	13,008	—	13,008
Series A Preferred Stock dividends	—	—	—	—	(2,721)	—	(2,721)	—	(2,721)
Accretion of beneficial conversion feature on Series A Preferred Stock	—	—	—	—	(1,596)	—	(1,596)	—	(1,596)
Repurchase of common stock	—	(77)	7,824	(32,135)	—	—	(32,212)	—	(32,212)
Restricted stock issued, net of tax withholdings	270	—	—	—	(454)	—	(454)	—	(454)
Net loss	—	—	—	—	—	(94,032)	(94,032)	—	(94,032)
Balance at March 31, 2019	176,480	$ 1,601	12,367	$ (64,872)	$ 2,157,923	$ (469,820)	$ 1,624,832	$ 151,837	$ 1,776,669

THE ACCOMPANYING NOTES ARE AN INTEGRAL PART OF
THESE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

EXTRACTION OIL & GAS, INC.
NOTES TO THE UNAUDITED CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business and Organization

Extraction Oil & Gas, Inc. (the "Company" or "Extraction") is an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and natural gas liquids ("NGLs") reserves in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin (the "DJ Basin") of Colorado, as well as the construction and support of midstream assets to gather and process crude oil and gas production. Extraction is a public company listed for trading on the NASDAQ Global Select Market under the symbol "XOG."

Deconsolidation of Elevation Midstream, LLC

Elevation Midstream, LLC ("Elevation"), a Delaware limited liability company, is focused on the construction and operation of gathering systems and facilities to serve the development of acreage in the Company's Hawkeye and Southwest Wattenberg areas. Midstream assets of Elevation are represented as the gathering systems and facilities line item within the condensed consolidated balance sheets.

During the first quarter of 2020, Elevation's non-controlling interest owner, which owns 100% of Elevation's preferred stock, per contractual agreement, expanded Elevation's then five member board of managers by four seats and filled them with managers of their choosing (the "Board Expansion"). Because Extraction had the right to appoint only three of the managers of Elevation before and after Board Expansion, Extraction determined the Company had lost voting control of Elevation, and on March 16, 2020 deconsolidated Elevation and began accounting for the entity as an equity method investment. Though Extraction determined control of Elevation was lost under the voting interest model of consolidation, the Company also determined significant influence was not lost due to (1) Extraction owning 100% of the common stock, (2) Extraction appointing three of the nine managers of Elevation and (3) Extraction's continuing involvement in the day-to-day operation of Elevation through a management services agreement. Because Extraction also determined the Company is not the primary beneficiary, Elevation Midstream, LLC is not a variable interest entity.

Extraction elected the fair value option to remeasure the Elevation equity method investment and determined it had no fair value. The Company recorded a $73.1 million loss on deconsolidation of the investment in the condensed consolidated statements of operations for the three months ended March 31, 2020. Also, as of March 31, 2020, Elevation determined certain gathering systems and facilities were impaired by $50.3 million as a result of the abandonment of certain projects. In accordance with Accounting Standards Codification *Topic 323-10-35-20: Investments—equity method and joint ventures*, Extraction discontinued applying the equity method investment for Elevation as the impairment charge would have reduced the investment below zero.

On May 1, 2020, Elevation's board of managers issued 1,530,000,000 common units at a price of $0.01 per unit to certain of Elevation's members other than Extraction (the "Capital Raise"). The Capital Raise caused Extraction's ownership of Elevation to be diluted to less than 0.01%. As a result of the Capital Raise, beginning in May 2020 Extraction will account for Elevation under the cost method of accounting. The Company reserves all rights related to actions taken by Elevation's board of managers.

Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements

Basis of Presentation

The unaudited condensed consolidated financial statements include the accounts of the Company, including its wholly owned subsidiaries. All significant intercompany balances and transactions have been eliminated in consolidation. The financial statements included herein were prepared from the records of the Company in accordance with generally accepted accounting principles in the United States ("GAAP") and the Securities and Exchange Commission rules and regulation for interim financial reporting. In the opinion of management, all adjustments, consisting primarily of normal recurring accruals that are considered necessary for a fair statement of the unaudited condensed consolidated financial information, have been included. However, operating results for the period presented are not necessarily indicative of the results that may be expected for a full year. Interim condensed consolidated financial

statements and the year-end balance sheets do not include all of the information and notes required by GAAP for audited annual consolidated financial statements. These unaudited condensed consolidated financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes included in the Company's Annual Report on Form 10-K for the year ended December 31, 2019 ("Annual Report").

Significant Accounting Policies

The significant accounting policies followed by the Company are set forth in Note 2 to the Company's consolidated financial statements in its Annual Report and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report. These unaudited condensed consolidated financial statements should be read in conjunction with the consolidated financial statements and notes included in the Company's Annual Report.

Revenue — Contract Balances

The Company has a certain revenue contract with an initial term beginning on November 1, 2016 and continuing until October 31, 2020 after which the contract begins an automatic month-to-month renewal unless terminated by either party giving notice at least 180 days prior to the effective termination date but in no event can either party give such notice earlier than November 1, 2020. Based on the accounting treatment pursuant to ASC 606 - Revenue from Contracts with Customers, the contract term ends on April 30, 2021 because it may be terminated by either party with no penalty effective as of such date. The contract term impacts the amount of consideration that can be included in the transaction price. Generally, under the Company's various sales contracts, the Company invoices customers once its performance obligations have been satisfied, at which point payment is unconditional. For the three months ended March 31, 2020, the Company allocated $8.5 million to a satisfied performance obligation recognized within oil sales under ASC 606. As of March 31, 2020, the Company estimated a performance obligation under ASC 606 of $46.2 million, of which $3.9 million is recorded in accounts payable and accrued liabilities and $42.3 million is recorded in other non-current liabilities. A corresponding asset was recorded in the amount of $13.0 million, of which $12.1 million is recorded in inventory, prepaid expenses and other and $0.9 million is recorded in other non-current assets. The asset will be amortized into revenue over the contractual term of the contract, and the liability will be relieved if a deficiency payment is made to the counterparty or when the Company's minimum volume commitments are fulfilled.

Other Operating Expenses

Other operating expenses were $52.6 million for the three months ended March 31, 2020. This amount is primarily made up of a $46.8 million loss contingency from an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. Please see *Note 13—Commitments and Contingencies* for further details. Also included in this amount is a $5.8 million charge to income for expenses related to a workforce reduction in February 2020.

Impairment of Oil and Gas Properties

The Company identified an impairment triggering event for its proved oil and gas properties as of March 31, 2020 due to the significant decrease in oil and gas prices during the first quarter of 2020. As such, the Company performed a quantitative assessment as of March 31, 2020, and proved property in its northern field was impaired. For the three months ended March 31, 2020 and 2019, the Company recognized $0.8 million and $8.2 million, respectively, in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field. The Company did not have any proved property impairment in its Core DJ Basin field, primarily because of the $1.3 billion impairment charge that was recorded in the fourth quarter of 2019.

Of the Company's $112.5 million in exploration and abandonment expenses for the three months ended March 31, 2020, $106.9 million was lease abandonment expense. Unproved oil and gas properties consist of costs to acquire unevaluated leases as well as costs to acquire unproved reserves. The Company evaluates significant unproved oil and gas properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. When successful wells are drilled on undeveloped leaseholds, unproved property costs are reclassified to proved properties and depleted on a unit-of-production basis. Impairment expense and

lease extension payments for unproved properties is reported in exploration and abandonment expenses in the condensed consolidated statements of operations.

Recent Accounting Pronouncements

In June 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2016-13, Financial Instruments—Credit Losses. In May 2019, ASU No. 2016-13 was subsequently amended by ASU No. 2019-04, Codification Improvements to Topic 326, Financial Instruments—Credit Losses and ASU No. 2019-05, Financial Instruments—Credit Losses (Topic 326): Targeted Transition Relief. ASU No. 2016-13, as amended, affects trade receivables, financial assets and certain other instruments that are not measured at fair value through net income. This ASU replaced the incurred loss approach with an expected loss model for instruments measured at amortized cost and was effective for financial statements issued for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. ASU No. 2016-13 will be applied using a modified retrospective approach through a cumulative-effect adjustment to retained earnings as of the beginning of the first reporting period in which the guidance is effective. The Company adopted this ASU on January 1, 2020, and the adoption did not have a material impact on the consolidated financial statements and related disclosures.

In August 2018, the FASB issued ASU No. 2018-13, which removes or modifies current fair value disclosures and adds additional disclosures. The update to the guidance is the result of the FASB's test of the principles developed in its disclosure effectiveness project, which is designed to improve the effectiveness of disclosures in the notes to the financial statements. The disclosures that have been removed or modified may be applied immediately with retrospective application. For public entities, the new guidance was effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company adopted this ASU on January 1, 2020, and the adoption did not have a material impact on the consolidated financial statements and related disclosures.

In August 2018, the FASB issued ASU No. 2018-15, which aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software and hosting arrangements that include an internal-use software license. For public entities, the guidance is effective for fiscal years beginning after December 15, 2019, including interim reporting periods within that reporting period. The Company adopted this ASU on January 1, 2020 which did not have a material impact on the consolidated financial statements and related disclosures as capitalized costs for internal-use software were not material as of March 31, 2020.

Other than as disclosed above or in the Company’s Annual Report, there are no other accounting standards applicable to the Company as of March 31, 2020 and through the date of this filing that would have a material effect on the Company’s unaudited condensed consolidated financial statements and related disclosures that have been issued but not yet adopted by the Company.

Note 3—Divestitures

February 2020 Divestiture

In February 2020, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $12.2 million, subject to customary purchase price adjustments. No gain or loss was recognized for the February 2020 Divestiture. The Company continues to explore divestitures as part of our ongoing initiative to divest non-strategic assets.

December 2019 Divestiture

In December 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $10.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the December 2019 Divestiture.

August 2019 Divestiture

In August 2019, the Company completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $22.0 million, subject to customary purchase price adjustments. No gain or loss was recognized for the August 2019 Divestiture.

March 2019 Divestiture

In March 2019, the Company completed the sale of its interests in approximately 5,000 net acres of leasehold and producing properties for aggregate sales proceeds of approximately $22.4 million. The effective date for the March 2019 Divestiture was July 1, 2018 with purchase price adjustments calculated as of the closing date of $5.9 million, resulting in net proceeds of $16.5 million. No gain or loss was recognized for the March 2019 Divestiture.

Note 4—Going Concern

The Company depends on cash flows from operating activities and, as necessary and available, borrowings under its senior secured revolving credit facility (the "revolving credit facility") to fund its capital expenditures and working capital requirements. Additionally, the Company historically has used proceeds from the issuance of equity and debt securities in the capital markets and from sales or other monetizations of assets to fund its capital expenditures and working capital requirements.

The market price for oil, natural gas and NGLs decreased significantly beginning in the first quarter of 2020, continuing into the second quarter of 2020. The decrease in the market price for the Company's production directly reduces the Company's cash flow from operations and indirectly impacts its other potential sources of funds described above. The Company has reduced its 2020 upstream capital budget and as a result expects to suspend drilling in the second half of 2020 and does not see production returning to historical levels for the foreseeable future. As discussed in *Note 5—Long-Term Debt*, lenders under the revolving credit facility elected to reduce the borrowing base and elected commitments to $650.0 million from $950.0 million on April 27, 2020, and the Company borrowed all of its remaining available capacity under the revolving credit facility. As a result of the reduction of the borrowing base and elected commitments, it is probable that the Company will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 when assuming the Company's current financial forecast.

If the Company does not obtain a waiver of its financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to accelerate maturity of the debt. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of the Company's other outstanding long-term debt amounting to approximately $1.1 billion. These defaults create uncertainty associated with the Company's ability to repay its outstanding long-term debt obligations as they become due and creates a substantial doubt over the Company's ability to continue as a going concern.

As a result of the impacts to the Company's financial position resulting from declining commodity price conditions and in consideration of the substantial amount of long-term debt and preferred stock outstanding, the Company has engaged advisors to assist with the evaluation of strategic alternatives, which may include, but not be limited to, seeking a restructuring, amendment or refinancing of existing debt through a private restructuring or reorganization under Chapter 11 of the Bankruptcy Code. However, there can be no assurances that the Company will be able to successfully restructure its indebtedness, improve its financial position or complete any strategic transactions. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding the Company's ability to continue as a going concern.

The consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect any adjustments that might result if the Company is unable to continue as a going concern.

Note 5—Long-Term Debt

The Company's long-term debt consisted of the following (in thousands):

	March 31, 2020	December 31, 2019
Credit facility due August 16, 2022 (or an earlier time as set forth in the credit facility)	$ 470,000	$ 470,000
2024 Senior Notes due May 15, 2024	400,000	400,000
2026 Senior Notes due February 1, 2026	700,189	700,189
Unamortized debt issuance costs on Senior Notes	(13,842)	(14,412)
Total long-term debt	1,556,347	1,555,777
Less: current portion of long-term debt	—	—
Total long-term debt, net of current portion	$ 1,556,347	$ 1,555,777

Credit Facility

In August 2017, the Company entered into an amendment and restatement of its existing credit facility (prior to amendment and restatement, the "Prior Credit Facility"), to provide aggregate commitments of $1.5 billion with a syndicate of banks, which is subject to a borrowing base. The credit facility matures on the earlier of (a) August 16, 2022, (b) April 15, 2021, if (and only if) (i) the Series A Preferred Stock have not been converted into common equity or redeemed prior to April 15, 2021 (the Company can redeem the Series A Preferred Stock at any time), and (ii) prior to April 15, 2021, the maturity date of the Series A Preferred Stock has not been extended to a date that is no earlier than six months after August 16, 2022 or (c) the earlier termination in whole of the commitments under the credit facility. No principal payments are generally required until the credit agreement matures or in the event that the borrowing base falls below the outstanding balance.

As of March 31, 2020, the credit facility had a maximum credit amount of $1.5 billion, subject to a borrowing base and elected commitments of $950.0 million. As of March 31, 2020 and December 31, 2019, the Company had outstanding borrowings of $470.0 million and had standby letters of credit of $49.5 million which reduces the availability of the undrawn borrowing base. At March 31, 2020, the undrawn balance under the credit facility was $480.0 million before letters of credit. The amount available to be borrowed under the Company's revolving credit facility is subject to a borrowing base that is redetermined semiannually on each May 1 and November 1, and will depend on the volumes of the Company's proved oil and gas reserves, commodity prices, estimated cash flows from these reserves and other information deemed relevant by the administrative agent under the Company's revolving credit facility. Additionally, the undrawn balance may be constrained by the Company's quantitative covenants under the credit facility, including the current ratio and ratio of consolidated debt less cash balances to its consolidated EBITDAX, at the next required quarterly compliance date.

On April 27, 2020, the lenders under our revolving credit facility provided notice to the Company that they had completed the redetermination scheduled to occur on May 1, 2020, and via this redetermination, our borrowing base had been reduced from $950.0 million to $650.0 million. As of May 11, 2020, following this redetermination, the Company had outstanding borrowings of $600.5 million and had standby letters of credit of $49.5 million, which reduce the availability of the undrawn borrowing base. As of the date of this filing, the available balance under the credit facility was zero.

Principal amounts borrowed on the credit facility will be payable on the maturity date. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. Amounts repaid under the credit facility may be re-borrowed from time to time, subject to the terms of the facility.

Interest on the credit facility is payable at one of the following two variable rates as selected by the Company: a base rate based on the Prime Rate or the Eurodollar rate, based on LIBOR. Either rate is adjusted upward by an applicable margin, based on the utilization percentage of the facility as outlined in the pricing grid below. Additionally, the credit facility provides for a commitment fee of 0.375% to 0.50%, depending on borrowing base usage. The grid below shows the Base Rate Margin and Eurodollar Margin depending on the applicable Borrowing Base Utilization Percentage (as defined in the credit facility) as of the date of this filing:

Borrowing Base Utilization Grid

Borrowing Base Utilization Percentage	Utilization	Eurodollar Margin	Base Rate Margin	Commitment Fee Rate
Level 1	<25%	1.50 %	0.50 %	0.38 %
Level 2	≥ 25% < 50%	1.75 %	0.75 %	0.38 %
Level 3	≥ 50% < 75%	2.00 %	1.00 %	0.50 %
Level 4	≥ 75% < 90%	2.25 %	1.25 %	0.50 %
Level 5	≥90%	2.50 %	1.50 %	0.50 %

The credit facility contains representations, warranties, covenants, conditions and defaults customary for transactions of this type, including but not limited to: (i) limitations on liens and incurrence of debt covenants; (ii) limitations on dividends, distributions, redemptions and restricted payments covenants; (iii) limitations on investments, loans and advances covenants; and (iv) limitations on the sale of property, mergers, consolidations and other similar transactions covenants. Additionally, the credit facility limits the Company entering into hedges in excess of 85% of its anticipated production volumes.

The credit facility also contains financial covenants requiring the Company to comply on the last day of each quarter with a current ratio of its restricted subsidiaries' current assets (includes availability under the revolving credit facility and unrestricted cash and excludes derivative assets) to its restricted subsidiaries' current liabilities (excludes obligations under the revolving credit facility, senior notes and certain derivative liabilities), of not less than 1.0 to 1.0 and to maintain, on the last day of each quarter, a ratio of its restricted subsidiaries' debt less cash balances to its restricted subsidiaries EBITDAX (EBITDAX is defined as net income adjusted for interest expense, income tax expense/benefit, DD&A, exploration and abandonment expenses as well as certain non-recurring cash and non-cash charges and income (such as stock-based compensation expense, unrealized gains/losses on commodity derivatives and impairment of long-lived assets and goodwill), subject to pro forma adjustments for non-ordinary course acquisitions and divestitures) for the four fiscal quarter periods most recently ended, of not greater than 4.0 to 1.0 as of the last day of such fiscal quarter. As of March 31, 2020, the Company was in compliance with the covenants under the credit agreement.

The Company's 2020 capital program remains focused on generating free cash flow with an emphasis on strengthening liquidity and the balance sheet as the Company works to pay down debt. However, factors including those outside of the Company's control may prevent maintaining compliance with such covenants, including commodity price declines and the Company's inability to access capital markets, to access the asset sale market or to execute on its business plan. Additionally, as a result of the reduction of the borrowing base and elected commitments described above, it is probable that the Company will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 under the Company's current financial forecast. The Company may seek covenant relief from the lenders under the revolving credit facility, and if the Company does not obtain a waiver of its financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to declare all outstanding principal and interest to be due and payable, and the lenders under the credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of the Company's other outstanding long-term debt.

Any borrowings under the credit facility are collateralized by substantially all of the assets of the Company and certain of its subsidiaries, including oil and gas properties, personal property and the equity interests of those subsidiaries of the Company. The Company has entered into oil and natural gas hedging transactions with several counterparties that are also lenders under the credit facility. The Company's obligations under these hedging contracts are secured by the collateral securing the credit facility. Elevation is an unrestricted subsidiary, which is no longer consolidated or controlled by the Company, and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries.

2024 Senior Notes

In August 2017, the Company issued at par $400.0 million principal amount of 7.375% Senior Notes due May 15, 2024 (the "2024 Senior Notes" and the offering, the "2024 Senior Notes Offering"). The 2024 Senior Notes bear an annual interest rate of 7.375%. The interest on the 2024 Senior Notes is payable on May 15 and November 15 of each year which commenced on November 15, 2017. The Company received net proceeds of approximately $392.6 million after deducting fees.

The Company's 2024 Senior Notes are its senior unsecured obligations and rank equally in right of payment with all of its other senior indebtedness and senior to any of its subordinated indebtedness. The Company's 2024 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantees its indebtedness under a credit facility (the "2024 Senior Notes Guarantors"). The 2024 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under its revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of any of its future subsidiaries that do not guarantee the 2024 Senior Notes.

The 2024 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the 2024 Senior Notes Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company’s or any of its 2024 Senior Notes Guarantors’ equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2024 Senior Notes also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2024 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2024 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2024 Senior Notes may declare all outstanding 2024 Senior Notes to be due and payable immediately.

2026 Senior Notes

In January 2018, the Company issued at par $750.0 million principal amount of 5.625% Senior Notes due February 1, 2026 (the "2026 Senior Notes" and together with the 2024 Senior Notes, the "Senior Notes" and the offering of the 2026 Senior Notes, the "2026 Senior Notes Offering"). The 2026 Senior Notes bear an annual interest rate of 5.625%. The interest on the 2026 Senior Notes is payable on February 1 and August 1 of each year commencing on August 1, 2018. The Company received net proceeds of approximately $737.9 million after deducting fees.

The Company's 2026 Senior Notes are the Company's senior unsecured obligations and rank equally in right of payment with all of the Company's other senior indebtedness and senior to any of the Company's subordinated indebtedness. The Company's 2026 Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of the Company's current subsidiaries and by certain future restricted subsidiaries that guarantee the Company's indebtedness under a credit facility (the "2026 Senior Notes Guarantors"). The 2026 Senior Notes are effectively subordinated to all of the Company's secured indebtedness (including all borrowings and other obligations under the Company's revolving credit facility) to the extent of the value of the collateral securing such indebtedness, and structurally subordinated in right of payment to all existing and future indebtedness and other liabilities (including trade payables) of certain of the Company's future restricted subsidiaries that do not guarantee the 2026 Senior Notes.

The 2026 Senior Notes also contain affirmative and negative covenants that, among other things, limit the Company's and the 2026 Senior Notes Guarantors' ability to make investments; declare or pay any dividend or make any other payment to holders of the Company's or any of its 2026 Senior Notes Guarantors' equity interests; repurchase or redeem any equity interests of the Company; repurchase or redeem subordinated indebtedness; incur additional indebtedness or issue preferred stock; create liens; sell assets; enter into agreements that restrict dividends or other

payments by restricted subsidiaries; consolidate, merge or transfer all or substantially all of the assets of the Company; engage in transactions with the Company's affiliates; engage in any business other than the oil and gas business; and create unrestricted subsidiaries. The indenture governing the 2026 Senior Notes also contains customary events of default. Upon the occurrence of events of default arising from certain events of bankruptcy or insolvency, the 2026 Senior Notes shall become due and payable immediately without any declaration or other act of the trustee or the holders of the 2026 Senior Notes. Upon the occurrence of certain other events of default, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding 2026 Senior Notes may declare all outstanding 2026 Senior Notes to be due and payable immediately.

Debt Issuance Costs

As of March 31, 2020, the Company had debt issuance costs, net of accumulated amortization, of $2.2 million related to its credit facility which has been reflected on the Company's condensed consolidated balance sheets within the line item other non-current assets. As of March 31, 2020, the Company had debt issuance costs net of accumulated amortization of $13.8 million related to its 2024 and 2026 Senior Notes which have been reflected on the Company's condensed consolidated balance sheets within the line item Senior Notes, net of unamortized debt issuance costs. Debt issuance costs include origination, legal, engineering, and other fees incurred in connection with the Company's credit facility and Senior Notes. For the three months ended March 31, 2020 and March 31, 2019, the Company recorded amortization expense related to the debt issuance costs of $1.2 million and $1.5 million, respectively.

Interest Incurred on Long-Term Debt

For the three months ended March 31, 2020, the Company incurred interest expense on long-term debt of $22.3 million as compared to $20.8 million for the three months ended March 31, 2019. For the three months ended March 31, 2020, the Company capitalized interest expense on long term debt of $2.1 million as compared to $2.0 million for the three months ended March 31, 2019, which has been reflected in the Company's consolidated financial statements.

Senior Note Repurchase Program

On January 4, 2019, the Board of Directors authorized a program to repurchase up to $100.0 million of the Company's Senior Notes (the "Senior Notes Repurchase Program"). The Company's Senior Notes Repurchase Program is subject to restrictions under our credit facility and does not obligate it to acquire any specific nominal amount of Senior Notes. For the three months ended March 31, 2020, the Company did not repurchase any Senior Notes. For the three months ended March 31, 2019, the Company repurchased a nominal value of $35.8 million for $28.5 million in connection with the Senior Notes Repurchase Program. Interest expense for the three months ended March 31, 2019 included a $7.3 million gain on debt repurchase related to the Company's Senior Note Repurchase Program.

Note 6—Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, as described below. The Company has utilized swaps, put options and call options to reduce the effect of price changes on a portion of the Company's future oil and natural gas production.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, the Company pays its counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of the Company's purchased put options have deferred premiums. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

The Company combines swaps, purchased put options, purchased call options, sold put options and sold call options in order to achieve various hedging strategies. Some examples of the Company's hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap.

The objective of the Company's use of commodity derivative instruments is to achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage its exposure to commodity price risk. While the use of these commodity derivative instruments limits the downside risk of adverse price movements, such use may also limit the Company's ability to benefit from favorable price movements. The Company may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the Company's existing positions. The Company does not enter into derivative contracts for speculative purposes.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

The use of derivatives involves the risk that the counterparties to such instruments will be unable to meet the financial terms of such contracts. The Company's derivative contracts are currently with nine counterparties, all but one of whom are lenders under our credit agreement. The Company has netting arrangements with the counterparties that provide for the offset of payables against receivables from separate derivative arrangements with the counterparties in the event of contract termination. The derivative contracts may be terminated by a non-defaulting party in the event of default by one of the parties to the agreement. There is no credit risk related contingent features or circumstances in which the features could be triggered in derivative instruments that are in a net liability position at the end of the reporting period.

The Company's commodity derivative contracts as of March 31, 2020 are summarized below:

	2020	2021	2022	2023
NYMEX WTI Crude Swaps:				
Notional volume (Bbl)	2,800,000	4,200,000	1,020,000	900,000
Weighted average fixed price ($/Bbl)	$ 59.75	$ 57.10	$ 54.84	$ 54.87
NYMEX WTI Crude Purchased Puts:				
Notional volume (Bbl)	5,300,000	3,600,000	—	—
Weighted average purchased put price ($/Bbl)	$ 54.83	$ 54.17	$ —	$ —
NYMEX WTI Crude Purchased Calls:				
Notional volume (Bbl)	250,000	—	—	—
Weighted average purchased call price ($/Bbl)	$ 57.06	$ —	$ —	$ —
NYMEX WTI Crude Sold Calls:				
Notional volume (Bbl)	6,250,000	3,600,000	—	—
Weighted average sold call price ($/Bbl)	$ 61.94	$ 61.93	$ —	$ —
NYMEX WTI Crude Sold Puts:				
Notional volume (Bbl)	8,100,000	7,800,000	600,000	600,000
Weighted average sold put price ($/Bbl)	$ 43.08	$ 43.27	$ 43.00	$ 43.00
NYMEX HH Natural Gas Swaps:				
Notional volume (MMBtu)	27,000,000	—	—	—
Weighted average fixed price ($/MMBtu)	$ 2.75	$ —	$ —	$ —
CIG Basis Gas Swaps:				
Notional volume (MMBtu)	34,200,000	2,400,000	—	—
Weighted average fixed basis price ($/MMBtu)	$ (0.61)	$ (0.57)	$ —	$ —

The following tables detail the fair value of the Company's derivative instruments, including the gross amounts and adjustments made to net the derivative instruments for the presentation in the condensed consolidated balance sheets (in thousands):

	As of March 31, 2020				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets in the Balance Sheet[1]**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet[2]**	**Net Amounts[3]**
Current assets	$ 293,761	$ (129,431)	$ 164,330	$ (716)	$ 252,397
Non-current assets	127,705	(38,922)	88,783	—	—
Current liabilities	(130,147)	129,431	(716)	716	—
Non-current liabilities	(38,922)	38,922	—	—	—

	As of December 31, 2019				
Location on Balance Sheet	**Gross Amounts of Recognized Assets and Liabilities**	**Gross Amounts Offsets in the Balance Sheet[1]**	**Net Amounts of Assets and Liabilities Presented in the Balance Sheet**	**Gross Amounts not Offset in the Balance Sheet[2]**	**Net Amounts[3]**
Current assets	$ 48,605	$ (31,051)	$ 17,554	$ —	$ 30,783
Non-current assets	38,034	(24,805)	13,229	—	—
Current liabilities	(33,049)	31,051	(1,998)	—	(2,106)
Non-current liabilities	(24,913)	24,805	(108)	—	—

(1) Agreements are in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.
(2) Netting for balance sheet presentation is performed by current and non-current classification. This adjustment represents amounts subject to an enforceable master netting arrangement, which are not netted on the condensed consolidated balance sheets. There are no amounts of related financial collateral received or pledged.
(3) Net amounts are not split by current and non-current. All counterparties in a net asset position are shown in the current asset line, and all counterparties in a net liability position are shown in the current liability line item.

The table below sets forth the commodity derivatives gain (loss) for the three months ended March 31, 2020 and 2019 (in thousands). Commodity derivatives gain (loss) are included under the other income (expense) line item in the condensed consolidated statements of operations.

	For the Three Months Ended March 31,	
	2020	2019
Commodity derivatives gain (loss)	$ 263,015	$ (122,091)

Note 7—Asset Retirement Obligations

The Company follows accounting for asset retirement obligations in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value could be made. The Company's asset retirement obligations primarily represent the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable local, state and federal laws, and applicable lease terms. The Company determines the estimated fair value of its asset retirement obligations by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company's credit adjusted discount rates, inflation rates and estimated dates of abandonment. The asset retirement liability is accreted to its present value each period and the capitalized asset retirement costs are depleted with proved oil and gas properties using the unit of production method.

The following table summarizes the activities of the Company's asset retirement obligations for the period indicated (in thousands):

	For the Three Months Ended March 31, 2020
Balance beginning of period	$ 95,908
Liabilities incurred or acquired	192
Liabilities settled	(10,787)
Revisions in estimated cash flows	6,638
Accretion expense	1,822
Balance end of period	$ 93,773

Note 8—Fair Value Measurements

ASC 820, *Fair Value Measurement and Disclosure*, establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company's assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

- Level 1: Quoted prices are available in active markets for identical assets or liabilities;
- Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability;
- Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flow models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. There were no transfers between levels during any periods presented below.

The following table presents the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2020 and December 31, 2019 by level within the fair value hierarchy (in thousands):

	Fair Value Measurement at March 31, 2020			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 253,113	$ —	$ 253,113
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 716	$ —	$ 716

	Fair Value Measurement at December 31, 2019			
	Level 1	Level 2	Level 3	Total
Financial Assets:				
Commodity derivative assets	$ —	$ 30,783	$ —	$ 30,783
Financial Liabilities:				
Commodity derivative liabilities	$ —	$ 2,106	$ —	$ 2,106

The following methods and assumptions were used to estimate the fair value of the assets and liabilities in the tables above:

Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market based approach that takes into account several factors, including quoted market prices in active markets, implied market volatility factors, quotes from third parties, the credit rating of each counterparty, and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the possibility of whether each counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. Derivative instruments utilized by the Company consist of swaps, put options and, call options. The oil and natural gas derivative markets are highly active. Although the Company's derivative instruments are valued using public indices, the instruments themselves are traded with third party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Financial Instruments

The Company's financial instruments consist primarily of cash and cash equivalents, accounts receivable, accounts payable, commodity derivative instruments (discussed above) and long-term debt. The carrying values of cash and cash equivalents, accounts receivable and accounts payable are representative of their fair values due to their short-term maturities. The carrying amount of the Company's credit facility approximated fair value as it bears interest at

variable rates over the term of the loan. The fair values of the 2024 Senior Notes and 2026 Senior Notes were derived from available market data. As such, the Company has classified the 2024 Senior Notes and 2026 Senior Notes as Level 2. Please refer to *Note 5—Long-Term Debt* for further information. The Company's policy is to recognize transfers between levels at the end of the period. This disclosure (in thousands) does not impact the Company's financial position, results of operations or cash flows.

	At March 31, 2020		At December 31, 2019	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Credit Facility	$ 470,000	$ 470,000	$ 470,000	$ 470,000
2024 Senior Notes[(1)]	$ 395,075	$ 68,000	$ 394,824	$ 250,000
2026 Senior Notes[(2)]	$ 691,272	$ 119,032	$ 690,953	$ 420,113

(1) The carrying amount of the 2024 Senior Notes includes unamortized debt issuance costs of $4.9 million and $5.2 million as of March 31, 2020 and December 31, 2019, respectively.
(2) The carrying amount of the 2026 Senior Notes includes unamortized debt issuance costs of $8.9 million and $9.2 million as of March 31, 2020 and December 31, 2019, respectively.

Non-Recurring Fair Value Measurements

The Company applies the provisions of the fair value measurement standard on a non-recurring basis to its non-financial assets and liabilities, including proved property. These assets and liabilities are not measured at fair value on a recurring basis, but are subject to fair value adjustments when facts and circumstances arise that indicate a need for remeasurement.

The Company utilizes fair value on a non-recurring basis to review its proved oil and gas properties for potential impairment when events and circumstances indicate, and at least annually, a possible decline in the recoverability of the carrying value of such property. The Company uses an income approach analysis based on the net discounted future cash flows of producing property. The future cash flows are based on management's estimates for the future. Unobservable inputs include estimates of oil and gas production, as the case may be, from the Company's reserve reports, commodity prices based on the sales contract terms and forward price curves, operating and development costs and a discount rate based on a market-based weighted average cost of capital (all of which are Level 3 inputs within the fair value hierarchy). For the three months ended March 31, 2020 and 2019, the Company recognized $0.8 million and $8.2 million, respectively, in impairment expense on its proved oil and gas properties related to impairment of assets in its northern field. The fair value did not exceed the Company's carrying amount associated with its proved oil and gas properties in its northern field.

Note 9—Income Taxes

The Company computes an estimated annual effective tax rate ("AETR") each quarter based on the current and forecasted operating results. The income tax expense or benefit associated with the interim period is computed using the most recent estimated AETR applied to the year-to-date ordinary income or loss, plus the tax effect of any significant or infrequently occurring items recorded during the interim period. The computation of the estimated AETR at each interim period requires certain estimates and significant judgements including, but not limited to, the expected operating income (loss) for the year, projections of the proportion of income earned and taxed in various jurisdictions, permanent differences and the likelihood of recovering deferred tax assets generated in the current year. The accounting estimates used to compute the provision for income taxes may change as new events occur, more experience is obtained, and additional information becomes known or as the tax environment changes.

The effective combined U.S. federal and state income tax rate for the three months ended March 31, 2020 and 2019 was 19.6% and 23.6%, respectively. The effective rate for the three months ended March 31, 2020 and 2019 differs from the amount that would be provided by applying the statutory U.S. federal income tax rate of 21% to pre-tax income due to (i) the effect of a full valuation allowance in effect at March 31, 2020 and (ii) the effects of state taxes, permanent taxable differences, and income attributable to non-controlling interest for the three months ended March 31, 2019.

Before accounting for a naked credit deferred tax liability, net tax expense for the three months ended March 31, 2020 was reduced to zero due to the valuation allowance. The naked credit deferred tax liability results in tax expense of $2.2 million for the three months ended March 31, 2020.

The Company considers whether some portion, or all, of the deferred tax assets ("DTAs") will be realized based on a more likely than not standard of judgment. The ultimate realization of DTAs is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. At December 31, 2019, the Company had a valuation allowance totaling $246.1 million against its DTAs resulting from prior year cumulative financial losses, oil and gas impairments, and significant net operating losses for U.S. federal and state income tax. The Company assesses the appropriateness of its valuation allowance on a quarterly basis. As of March 31, 2020, there was no change in the Company's assessment of the realizability of its DTAs, except for a naked credit deferred tax liability.

Note 10—Stock-Based Compensation

Extraction Long Term Incentive Plan

In October 2016, the Company's board of directors adopted the Extraction Oil & Gas, Inc. 2016 Long Term Incentive Plan (the "2016 Plan" or "LTIP"), pursuant to which employees, consultants and directors of the Company and its affiliates performing services for the Company are eligible to receive awards. The 2016 Plan provides for the grant of stock options, stock appreciation rights, restricted stock, restricted stock units, bonus stock, dividend equivalents, other stock-based awards, substitute awards, annual incentive awards and performance awards intended to align the interests of participants with those of stockholders. In May 2019, the Company's stockholders approved the amendment and restatement of the Company's 2016 Long Term Incentive Plan. The amended and restated 2016 Long Term Incentive Plan provides a total reserve of 32.2 million shares of common stock for issuance pursuant to awards under the LTIP. Extraction has granted awards under the LTIP to certain directors, officers and employees, including stock options, restricted stock units, performance stock awards, performance stock units, performance cash awards and cash awards.

Restricted Stock Units

Restricted stock units granted under the LTIP ("RSUs") generally vest over either a one or three-year service period, with 100% vesting in year one or 25%, 25% and 50% of the units vesting in year one, two and three, respectively. Grant date fair value was determined based on the value of Extraction's common stock pursuant to the terms of the LTIP. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded $0.8 million of stock-based compensation costs related to RSUs for the three months ended March 31, 2020 as compared to $6.9 million for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there was $8.3 million of total unrecognized compensation cost related to the unvested RSUs granted to certain directors, officers and employees that is expected to be recognized over a weighted average period of 2.2 years.

The following table summarizes the RSU activity from January 1, 2020 through March 31, 2020 and provides information for RSUs outstanding at the dates indicated.

	Number of Shares		Weighted Average Grant Date Fair Value
Non-vested RSUs at January 1, 2020	2,635,765	$	8.32
Granted	1,252,000	$	0.31
Forfeited	(351,679)	$	9.44
Vested	(356,008)	$	14.23
Non-vested RSUs at March 31, 2020	3,180,078	$	4.38

Performance Stock Awards

The Company granted performance stock awards ("PSAs") to certain executives under the LTIP in October 2017, March 2018, April 2019 and March 2020. The number of shares of the Company's common stock that may be issued to settle these various PSAs ranges from zero to two times the number of PSAs awarded. PSA's that settle in cash are presented as liability based awards. Generally, the shares issued for PSAs are determined based on the satisfaction of a time-based vesting schedule and a weighting of one or more of the following: (i) absolute total stockholder return ("ATSR"), (ii) relative total stockholder return ("RTSR"), as compared to the Company's peer group and (iii) cash return on capital invested ("CROCI") or return on invested capital ("ROIC") measured over a three-year period and vest in their entirety at the end of the three-year measurement period. Any PSAs that have not vested at the end of the applicable measurement period are forfeited. The vesting criterion that is associated with the RTSR is based on a comparison of the Company's total shareholder return for the measurement period compared to that of a group of peer companies for the same measurement period. As the ATSR and RTSR vesting criteria are linked to the Company's share price, they each are considered a market condition for purposes of calculating the grant-date fair value of the awards. The vesting criterion that is associated with the CROCI and ROIC are considered a performance condition for purposes of calculating the grant-date fair value of the awards.

The fair value of the PSAs was measured at the grant date with a stochastic process method using a Monte Carlo simulation. A stochastic process is a mathematically defined equation that can create a series of outcomes over time. Those outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSAs, the Company cannot predict with certainty the path its stock price or the stock prices of its peer will take over the performance period. By using a stochastic simulation, the Company can create multiple prospective stock pathways, statistically analyze these simulations, and ultimately make inferences regarding the most likely path the stock price will take. As such, because future stock prices are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the Monte Carlo Model, is deemed an appropriate method by which to determine the fair value of the PSAs. Significant assumptions used in this simulation include the Company's expected volatility, risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the measurement period as well as the volatilities for each of the Company's peers.

The Company recorded a credit of $0.8 million of stock-based compensation costs related to PSAs for the three months ended March 31, 2020 as compared to $1.5 million of stock-based compensation costs related to PSAs for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there was $5.2 million of total unrecognized compensation cost related to the unvested PSAs granted to certain executives that is expected to be recognized over a weighted average period of 2.3 years.

The following table summarizes the PSA activity from January 1, 2020 through March 31, 2020 and provides information for PSAs outstanding at the dates indicated.

	Number of Shares [1]		Weighted Average Grant Date Fair Value
Non-vested PSAs at January 1, 2020	2,863,190	$	7.72
Granted	5,952,700	$	0.29
Forfeited	—	$	—
Vested	—	$	—
Non-vested PSAs at March 31, 2020	8,815,890	$	2.70

(1) The number of awards assumes that the associated maximum vesting condition is met at the target amount. The final number of shares of the Company's common stock issued may vary depending on the performance multiplier, which ranges from zero to one for the 2017 and 2018 grants and ranges from zero to two for the 2019 and 2020 grants, depending on the level of satisfaction of the vesting condition.

Stock Options

Expense on the stock options is recognized on a straight-line basis over the service period of the award less awards forfeited. The fair value of the stock options was measured at the grant date using the Black-Scholes valuation model. The Company utilizes the "simplified" method to estimate the expected term of the stock options granted as there is limited historical exercise data available in estimating the expected term of the stock options. Expected volatility is based on the volatility of the historical stock prices of the Company's peer group. The risk-free rates are based on the yields of U.S. Treasury instruments with comparable terms. A dividend yield and forfeiture rate of zero were assumed. Stock options granted under the LTIP vest ratably over three years and are exercisable immediately upon vesting through the tenth anniversary of the grant date. To fulfill options exercised, the Company will issue new shares.

The Company recorded no stock-based compensation costs related to stock options for the three months ended March 31, 2020, as compared to $3.8 million for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there are no remaining unrecognized compensation costs related to the stock options granted to certain executives.

There was no stock option activity from January 1, 2020 through March 31, 2020. However, as of March 31, 2020, there was approximately 5.2 million outstanding and exercisable stock options with a weighted-average exercise price of $18.50.

Incentive Restricted Stock Units

Officers of the Company contributed 2.7 million shares of common stock to Extraction Employee Incentive, LLC ("Employee Incentive"), which is owned solely by certain officers of the Company. Employee Incentive issued restricted stock units ("Incentive RSUs") to certain employees. Incentive RSUs vested over a three year service period, with 25%, 25% and 50% of the units vesting in year one, two and three, respectively. On July 17, 2017, the partners of Employee Incentive amended the vesting schedule in which 25% vested immediately and the remaining Incentive RSUs vest 25%, 25% and 25% each six months thereafter, over the remaining 18-month service period. Grant date fair value was determined based on the value of the Company's common stock on the date of issuance. The Company assumed a forfeiture rate of zero as part of the grant date estimate of compensation cost.

The Company recorded no stock-based compensation costs related to Incentive RSUs for the three months ended March 31, 2020. The Company recorded $0.8 million of stock-based compensation costs related to Incentive RSUs for the three months ended March 31, 2019. These costs were included in the condensed consolidated statements of operations within the general and administrative expenses line item. As of March 31, 2020, there are no remaining unrecognized compensation costs related to the Incentive RSUs granted to certain employees.

Note 11—Equity

Series A Preferred Stock

The holders of our Series A Preferred Stock (the "Series A Preferred Holders") are entitled to receive a cash dividend of 5.875% per year, payable quarterly in arrears, and we have the ability to pay such quarterly dividends in kind at a dividend rate of 10% per year (decreased proportionately to the extent such quarterly dividends are partially paid in cash). We have paid the quarterly dividends in kind since the fourth quarter of 2019, and expect to pay future quarterly dividends in kind. The Series A Preferred Stock is convertible into shares of our common stock at the election of the Series A Preferred Holders at a conversion ratio per share of Series A Preferred Stock of 61.9195. Until the three-year anniversary of the closing of the IPO, we could elect to convert the Series A Preferred Stock at a conversion ratio per share of Series A Preferred Stock of 61.9195, but only if the closing price of our common stock had traded at or above a certain premium to our initial offering price, such premium to decrease with time. On October 15, 2019, the three year anniversary had passed for the Series A Preferred Stock to convert into our common stock. We can now redeem the Series A Preferred Stock at any time for the liquidation preference, which is $194.7 million. In certain situations, including a change of control, the Series A Preferred Stock may be redeemed for cash in an amount equal to the greater of (i) 135% of the liquidation preference of the Series A Preferred Stock and (ii) a 17.5% annualized internal rate of return on the liquidation preference of the Series A Preferred Stock. The Series A Preferred Stock matures on October

15, 2021, at which time they are mandatorily redeemable for cash at the liquidation preference to the extent there are legally available funds to do so. For more information, see the Company's Annual Report.

Elevation Common Units

On May 1, 2020, Elevation's board of managers issued 1,530,000,000 common units at a price of $0.01 per unit to certain of Elevation's members other than Extraction (the "Capital Raise"). The Capital Raise caused Extraction's ownership of Elevation to be diluted to less than 0.01%. As a result of the Capital Raise, beginning in May 2020 Extraction will account for Elevation under the cost method of accounting. The Company reserves all rights related to actions taken by Elevation's board of managers.

Elevation Preferred Units

In July 2018 and July 2019, respectively, Elevation sold 150,000 and 100,000 of Elevation Preferred Units at a price of $990 per unit to a third party (the "Purchaser"). The aggregate liquidation preference when the units were sold was $150.0 million and $100.0 million, respectively. These Preferred Units represent the noncontrolling interest presented on the condensed consolidated balance sheets, condensed consolidated statements of operations and condensed consolidated statements of changes in stockholders' equity and noncontrolling interest. As of March 16, 2020, Elevation is a separate, deconsolidated entity and the assets and credit of Elevation are not available to satisfy the debts and other obligations of the Company or its other subsidiaries. As part of the July 2018 transaction, the Company committed to Elevation that it would drill at least 425 qualifying wells in the acreage dedicated to Elevation by December 31, 2023, subject to reductions if Extraction does not sell the full amount of additional Elevation Preferred Units to the Purchaser. Pursuant to the Fourth Amendment to the Elevation Gathering Agreements between Elevation and Extraction, this drilling commitment would be eliminated, if and only if all Elevation Preferred Units have been redeemed in full or are otherwise no longer outstanding. Please see *Note 13—Commitments and Contingencies — Elevation Gathering Agreements* for further details.

Upon deconsolidation of Elevation Midstream, LLC as discussed in *Note 1—Business and Organization*, the $270.5 million Elevation preferred unit balance in the noncontrolling interest line item of the condensed consolidated balance sheets as of March 31, 2020 was removed. The amount comprises the line item effects of deconsolidation of Elevation Midstream, LLC on the condensed consolidated statements of changes in stockholders' equity and noncontrolling interest as of March 31, 2020.

During the twenty-eight months following the July 3, 2018 Preferred Unit closing date, Elevation is required to pay the Purchaser a quarterly commitment fee payable in cash or in kind of 1.0% per annum on any undrawn amounts of such additional $250.0 million commitment. For the three months ended March 31, 2020 and 2019, respectively, Elevation recognized $0.6 million and $0.9 million of commitment fees paid-in-kind included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the condensed consolidated statements of changes in stockholders' equity and noncontrolling interest.

The Elevation Preferred Units entitle the Purchaser to receive quarterly dividends at a rate of 8.0% per annum. In respect of quarters ending prior to and including June 30, 2020, the Dividend is payable in cash or in kind at the election of Elevation. After June 30, 2020, the Dividend is payable solely in cash. For the three months ended March 31, 2020 and 2019, respectively, Elevation recognized $5.5 million and $3.1 million of dividends paid-in-kind included under the Preferred Unit commitment fees and dividends paid-in-kind line item in the condensed consolidated statements of changes in stockholders' equity and noncontrolling interest.

Note 12—Earnings (Loss) Per Share

Basic earnings per share ("EPS") includes no dilution and is computed by dividing net income (loss) available to common shareholders by the weighted average number of shares outstanding during the period. Diluted EPS reflects the potential dilution of securities that could share in the earnings of the Company.

The Company uses the "if-converted" method to determine potential dilutive effects of the Company's outstanding Series A Preferred Stock and the treasury method to determine the potential dilutive effects of outstanding

restricted stock awards and stock options. The basic weighted average shares outstanding calculation is based on the actual days in which the shares were outstanding for the three months ended March 31, 2020 and 2019.

The components of basic and diluted EPS were as follows (in thousands, except per share data):

	For the Three Months Ended March 31,	
	2020	2019
Basic and Diluted Income (Loss) Per Share		
Net income (loss)	$ 9,037	$ (94,032)
Less: Noncontrolling interest	(6,160)	(3,975)
Less: Adjustment to reflect Series A Preferred Stock dividends	(4,748)	(2,721)
Less: Adjustment to reflect accretion of Series A Preferred Stock discount	(1,770)	(1,596)
Adjusted net loss available to common shareholders, basic and diluted	$ (3,641)	$ (102,324)
Denominator:		
Weighted average common shares outstanding, basic and diluted [1] [2]	137,726	170,702
Loss Per Common Share		
Basic and diluted	$ (0.03)	$ (0.60)

(1) For the three months ended March 31, 2020, 8,339,698 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

(2) For the three months ended March 31, 2019, 8,017,004 potentially dilutive shares, including restricted stock awards and stock options outstanding, were not included in the calculation above, as they had an anti-dilutive effect on EPS. Additionally, 11,472,445 common shares associated with the assumed conversion of Series A Preferred Stock were also excluded, as they would have had an anti-dilutive effect on EPS.

Note 13—Commitments and Contingencies

General

As is customary in the oil and gas industry, the Company may at times have commitments in place to reserve or earn certain acreage positions or wells. If the Company does not meet such commitments, the acreage positions or wells may be lost, or the Company may be required to pay damages if certain performance conditions are not met.

Leases

The Company has entered into operating leases for certain office facilities, compressors and office equipment. Maturities of operating lease liabilities associated with right-of-use assets and including imputed interest were as follows (in thousands):

	As of March 31, 2020		As of December 31, 2019
2020 - remaining	13,653	2020	19,040
2021	5,247	2021	5,247
2022	2,211	2022	2,211
2023	2,246	2023	2,246
2024	2,301	2024	2,301
Thereafter	8,273	Thereafter	8,273
Total lease payments	33,931	Total lease payments	39,318
Less imputed interest [1]	(4,264)	Less imputed interest [1]	(4,735)
Present value of lease liabilities [2]	$ 29,667	Present value of lease liabilities [2]	$ 34,583

(1) Calculated using the estimated interest rate for each lease.

(2) Of the total present value of lease liabilities as of March 31, 2020 and December 31, 2019, $15.2 million and $17.4 thousand, respectively, were recorded in accounts payable and accrued liabilities and $14.5 million and $17.2 thousand, respectively, were recorded in other non-current liabilities on the condensed consolidated balance sheets.

Drilling Rigs

As of March 31, 2020, the Company was subject to commitments on two drilling rigs contracted through May 2020 and February 2021. These costs are capitalized within proved oil and gas properties on the condensed consolidated balance sheets and are included as short-term lease costs. In the event of early termination of these contracts, the Company would be obligated to pay an aggregate amount of approximately $9.0 million as of March 31, 2020, as required under the terms of the contracts. Subsequent to March 31, 2020, the Company renegotiated the terms of the drilling rig contracts. After the modifications, in the event of early termination, the Company would be obligated to pay an aggregate amount of approximately $8.0 million as of May 6, 2020.

Delivery Commitments

As of March 31, 2020, the Company's oil marketer is subject to a firm transportation agreement that commenced in November 2016 and has a ten-year term with a monthly minimum delivery commitment of 45,000 Bbl/d in year one, 55,800 Bbl/d in year two, 61,800 Bbl/d in years three through seven and 58,000 Bbl/d in years eight through ten. In May 2017, the Company amended its agreement with its oil marketer that requires it to sell all of its crude oil from an area of mutual interest in exchange for a make-whole provision that allows the Company to satisfy any minimum volume commitment deficiencies incurred by its oil marketer with future barrels of crude oil in excess of their minimum volume commitment during the contract term. In May 2019, the Company extended the term of this agreement through October 31, 2020 subject to an evergreen provision thereafter where either party can provide a six month notice of termination beginning November 1, 2020. Due to the contract termination date, the amount of consideration recognized in revenue is reduced. Please see *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements — Revenue — Contract Balances*. The Company has posted a letter of credit for this agreement in the amount of $40.0 million. The Company may be required to pay a shortfall fee for any volume deficiencies under these commitments. The aggregate remaining amount of estimated payments under these agreements is approximately $655.8 million.

The Company has two long-term crude oil gathering commitments with a unconsolidated subsidiary, in which the Company had a minority ownership interest. Please see *Note 1—Business and Organization* for information related to the deconsolidation of Elevation Midstream, LLC. The first agreement commenced in November 2016 and has a term of ten years with a minimum volume commitment of an average of 9,167 Bbl/d in year one, 17,967 Bbl/d in year two, 18,800 Bbl/d for years three through five and 10,000 Bbl/d for years six through ten. The Company may be required to pay a shortfall fee for any volume deficiencies under this commitment. The second agreement commenced in July 2019 and has a term of ten years for an average of 3,200 Bbl/d in year one, 8,000 Bbl/d in year two, 14,000 Bbl/d in year three, 16,000 Bbl/d in years four through eight, 12,000 Bbl/d in year nine and 10,000 Bbl/d in year ten. The Company may be

required to pay a shortfall fee for any volume deficiencies under this commitment. The aggregate remaining amount of estimated payments under these agreements is approximately $117.7 million.

In February 2019, the Company entered into two long-term gas gathering and processing agreements with third-party midstream providers. One of the agreements additionally includes a long-term NGL sales commitment for take-in-kind NGLs from other processing agreements. The first agreement commenced in November 2019 and has a term of twenty years with a minimum volume commitment of 251 Bcf to be delivered within the first seven years. The annual commitments over seven years are to be delivered on an average 85,000 Mcf/d in year one, 125,000 Mcf/d in year two, 140,000 Mcf/d in year three, 118,000 Mcf/d in year four, 98,000 Mcf/d in year five, 70,000 Mcf/d in year six and 52,000 Mcf/d in year seven. The aggregate remaining amount of estimated payments under this agreement is approximately $299.3 million. The second agreement commenced on January 2020 and has a term of ten years with an annual minimum volume commitment of 13.0 Bcf in years one through ten. The second agreement also includes a commitment to sell take-in-kind NGLs of 4,000 Bbl/d in year one and 7,500 Bbl/d in years two through seven with the ability to roll up to a 10% shortfall in a given month to the subsequent month. The Company may be required to pay a shortfall fee for any volume deficiencies under these commitments, calculated based on the applicable gathering and processing fees and/or, with respect to the NGL commitment, the NGL transport cost. Under its current drilling plans, the Company expects to meet these volume commitments.

The summary of these minimum volume commitments as of March 31, 2020, was as follows:

	Oil (MBbl)	Gas (MMcf)	Total (MBOE)
2020 - remaining	6,492	25,815	10,794
2021	9,797	46,540	17,554
2022	8,944	49,758	17,237
2023	9,490	41,850	16,465
2024	9,516	34,160	15,209
Thereafter	29,860	40,260	36,570
Total	74,099	238,383	113,829

In collaboration with several other producers and a midstream provider, on December 15, 2016 and August 7, 2017, the Company agreed to participate in expansions of natural gas gathering and processing capacity in the DJ Basin. The plan includes two new processing plants as well as the expansion of related gathering systems. The first plant commenced operations in August 2018 and the second plant commenced operations in July 2019. The Company's share of these commitments will require an incremental 51.5 and 20.6 MMcf per day, respectively, over a baseline volume of 65 MMcf per day to be delivered after the plants' in-service dates for a period of seven years thereafter. The Company may be required to pay a shortfall fee for any incremental volume deficiency under these commitments. These contractual obligations can be reduced by the Company's proportionate share of the collective volumes delivered to the plants by other third-party incremental volumes available to the midstream provider at the new facilities that are in excess of the total commitments. The Company is also required for the first three years of each contract to guarantee a certain target profit margin on these volumes sold.

In July 2019, the Company entered into three long-term contracts to supply 125,000 dekatherms of residue gas per day for five years to a transportation company. While our production is expected to satisfy these contracts, the aggregate remaining amount of estimated commitment assuming no production is $31.0 million. The Company has posted a letter of credit for this agreement in the amount of $8.7 million.

The aggregate remaining amount of estimated remaining payments under these agreements is $1,103.8 million.

Elevation Gathering Agreements

In November 2018, the Company entered into three long-term gathering agreements (the "Elevation Gathering Agreements") for gas, crude oil and produced water with Elevation. Under the agreements, the Company agreed to drill 100 wells in Broomfield and 325 wells in Hawkeye by December 31, 2023 if both facilities are to be built. Elevation has alleged that if the Company fails to complete the wells by the commitment deadline, then it would be in breach of the agreement and Elevation could attempt to assert damages against Extraction and its affiliates. During the first quarter of 2020, Elevation postponed indefinitely further development of gathering systems and facilities that were to be constructed to service the Company's acreage in Hawkeye and another project in the Southwest Wattenberg area. Due to the decision to not complete the Hawkeye facilities and based on the amount of capital invested, the drilling commitment now consists of 297 wells in the Broomfield area of operations.

In April 2019, the Elevation Gathering Agreements were amended to provide for, among other amendments, the inclusion of additional gathering facilities in Elevation’s Badger facility. Pursuant to this amendment, Elevation has asserted that the additional gathering facilities were required to be completed by April 1, 2020 or, within 30 days of such date, Elevation could assert that Extraction must make a payment to Elevation in the amount of 135% of all costs incurred by Elevation as of such date for the development and construction of such additional gathering facilities. As of March 31, 2020, the costs incurred by Elevation for these additional gathering facilities totaled $34.7 million. The Company did not complete these additional gathering facilities by April 1, 2020, and Elevation has alleged that Extraction is in breach of the Elevation Gathering Agreements. On April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under *ASC Topic 450 - Contingencies*, the Company recorded the amount in accounts payable and accrued liabilities, related party on the condensed consolidated balance sheet as of March 31, 2020 and in other operating expenses on the condensed consolidated statements of operations.

In December 2019, the Elevation Gathering Agreements were further amended to provide Elevation additional connection fees that are consistent with market terms (the "Connect Fees"). In the fourth quarter of 2019, the Company incurred $19.5 million for Connect Fees pursuant to the Elevation Gathering Agreements, and in the first quarter of 2020 the Company incurred and paid $23.5 million. The Company does not expect to incur additional Connect Fees for the year ending December 31, 2020.

In March 2020, the Elevation Gathering Agreements were further amended to reset all gathering rates and eliminate existing minimum drilling commitment. This amendment will not become effective until after all Elevation Preferred Units have been redeemed in full or are otherwise no longer outstanding.

Litigation and Legal Items

The Company is involved in various legal proceedings and reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the Company’s best interests. The Company has provided the necessary estimated accruals in the condensed consolidated balance sheets where deemed appropriate for litigation and legal related items that are ongoing and not yet concluded. Although the results cannot be known with certainty, the Company currently believes that the ultimate results of such proceedings will not have a material adverse effect on our business, financial position, results of operations or liquidity.

Environmental. Due to the nature of the natural gas and oil industry, the Company is exposed to environmental risks. The Company has various policies and procedures to minimize and mitigate the risks from environmental contamination or with respect to environmental compliance issues. Liabilities are recorded when environmental damages resulting from past events are probable and the costs can be reasonably estimated. Except as discussed herein, the Company is not aware of any material environmental claims existing as of March 31, 2020 which have not been provided for or would otherwise have a material impact on our financial statements; however, there can be no assurance that current regulatory requirements will not change or that unknown potential past non-compliance with environmental laws, compliance matters or other environmental liabilities will not be discovered on our properties. Accrued environmental liabilities are recorded in accounts payable and accrued liabilities on the condensed consolidated balance sheets. The liability ultimately incurred with respect to a matter may exceed the related accrual.

COGCC Notices of Alleged Violations ("NOAVs"). The Company has received NOAVs from the COGCC for alleged compliance violations that the Company has responded to. At this time, the COGCC has not alleged any specific penalty amounts in these matters. The Company does not believe that any penalties that could result from these NOAVs will have a material effect on our business, financial condition, results of operations or liquidity, but they may exceed $100,000.

Midstream Connections. The Company had dedicated the production from some acreage to a certain midstream service provider. However, the Company was unable to connect well pads to the provider due to the inability to secure right of way access for building the connection pipeline. Because the acreage's production was dedicated to the midstream provider, they have invoiced the Company for oil and gas handled by other midstream providers. The Company disputes these invoices based on force majeure and may have other contractual or legal defenses. The Company's maximum exposure as of March 31, 2020 was $15.7 million. As of March 31, 2020, no contingent liability has been recorded as the amount of the loss cannot be reasonably estimated.

Elevation Matador Facility. Under the Elevation LLC Agreement, the Company is required to complete the gathering facilities in Elevation's Matador facility servicing the Company's Hawkeye area by August 1, 2020. As part of the Company's abandonment of further developing this Matador gathering system and facilities that were being constructed, Elevation has alleged that Extraction will be required to reimburse Elevation for all such expenditures on this project. Elevation is currently disputing certain costs related to this project with a third-party contractor that was working on the project. The Company's maximum exposure as of March 31, 2020 was $20.7 million. As of March 31, 2020, no contingent liability has been recorded as the amount of the loss cannot be reasonably estimated.

Elevation Gathering. As discussed above under *Elevation Gathering Agreements*, on April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under *ASC Topic 450 - Contingencies*, the Company recorded the amount in accounts payable and accrued liabilities, related party on the condensed consolidated balance sheet as of March 31, 2020 and in other operating expenses on the condensed consolidated statements of operations.

Note 14—Related Party Transactions

2024 Senior Notes

Several 5% stockholders of the Company were also holders of the 2024 Senior Notes. As of the initial issuance in August 2017 of the $400.0 million principal amount on the 2024 Senior Notes, such stockholders held $54.9 million.

2026 Senior Notes

Several holders of the 2026 Senior Notes are also 5% stockholders of the Company. As of the initial issuance in January 2018 of the $750.0 million principal amount on the 2026 Senior Notes, such stockholders held $56.2 million.

Elevation Midstream, LLC

As discussed in *Note 13—Commitments and Contingencies*, on April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under *ASC Topic 450 - Contingencies*, the Company recorded the amount in accounts payable and accrued liabilities, related party on the condensed consolidated balance sheet as of March 31, 2020 and in other operating expenses on the condensed consolidated statements of operations.

Note 15—Segment Information

Beginning in the fourth quarter of 2018, the Company had two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction of and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Elevation Midstream, LLC comprised the gathering and facilities segment. During the three months ending March 31, 2019, the Company's gathering and facilities segment was in the construction phase and no revenue generating activities had commenced. Through March 16, 2020, the results of Elevation were included in the consolidated financial statements of Extraction. Effective March 17, 2020, the results of Elevation Midstream, LLC are no longer consolidated in Extraction's results; however, the Company's segment disclosures include the gathering and facilities segment because it was consolidated through March 16, 2020. Please see *Note 1—Business and Organization* for further information related to the deconsolidation of Elevation Midstream, LLC. After March 31, 2020, Extraction will report as a single operating segment.

The following table presents a reconciliation of Adjusted EBITDAX by segment to the GAAP financial measure of income (loss) before income taxes for the three months ended March 31, 2020 and 2019 (in thousands).

	For the Three Months Ended March 31,	
	2020	2019
Reconciliation of Adjusted EBITDAX to Income (Loss) Before Income Taxes		
Exploration and production segment EBITDAX	$ 122,639	$ 138,339
Gathering and facilities segment EBITDAX	1,256	(152)
Subtotal of Reportable Segments	$ 123,895	$ 138,187
Less:		
Depletion, depreciation, amortization and accretion	$ (76,051)	$ (118,770)
Impairment of long lived assets	(775)	(8,248)
Other operating expenses	(52,575)	—
Exploration and abandonment expenses	(112,480)	(6,194)
Gain on sale of property and equipment	—	222
Gain (loss) on commodity derivatives	263,015	(122,091)
Settlements on commodity derivative instruments	(39,295)	10,329
Premiums paid for derivatives that settled during the period	—	9,549
Stock-based compensation expense	—	(13,008)
Amortization of debt issuance costs	(1,242)	(1,497)
Gain on repurchase of 2026 Senior Notes	—	7,317
Interest expense	(20,116)	(18,828)
Loss on deconsolidation of Elevation Midstream, LLC	(73,139)	—
Income (Loss) Before Income Taxes	$ 11,237	$ (123,032)

Financial information of the Company's reportable segments was as follows for the three months ended March 31, 2020 and 2019 (in thousands).

	For the Three Months Ended March 31, 2020			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from third parties	$ 163,714	$ 1,473	$ —	$ 165,187
Revenues from Extraction	—	4,513	(4,513)	—
Total Revenues	$ 163,714	$ 5,986	$ (4,513)	$ 165,187
Operating Expenses and Other Income (Expense):				
Direct operating expenses	$ (70,924)	$ (3,935)	$ 4,294	$ (70,565)
Depletion, depreciation, amortization and accretion	(74,952)	(1,099)	—	(76,051)
Interest income	61	29	—	90
Interest expense	(21,358)	—	—	(21,358)
Earnings in unconsolidated subsidiaries	—	480	—	480
Subtotal Operating Expenses and Other Income (Expense):	$ (167,173)	$ (4,525)	$ 4,294	$ (167,404)
Segment Assets	$ 2,703,388	$ —	$ —	$ 2,703,388
Capital Expenditures	155,441	(6,311)	—	149,130
Investment in Equity Method Investees	—	—	—	—
Segment EBITDAX	122,639	1,256	—	123,895

	For the Three Months Ended March 31, 2019			
	Exploration and Production	Gathering and Facilities	Elimination of Intersegment Transactions	Consolidated Total
Revenues:				
Revenues from third parties	$ 221,917	$ —	$ —	$ 221,917
Revenues from Extraction	—	—	—	—
Total Revenues	$ 221,917	$ —	$ —	$ 221,917
Operating Expenses and Other Income (Expense):				
Direct operating expenses	$ —	$ —	$ —	$ —
Depletion, depreciation, amortization and accretion	(118,751)	(19)	—	(118,770)
Interest income	154	625	—	779
Interest expense	(13,008)	—	—	(13,008)
Earnings in unconsolidated subsidiaries	—	338	—	338
Subtotal Operating Expenses and Other Income (Expense):	$ (131,605)	$ 944	$ —	$ (130,661)
Segment Assets	$ 3,813,513	$ 284,200	$ (714)	$ 4,096,999
Capital Expenditures	158,622	58,863	—	217,485
Investment in Equity Method Investees	—	17,555	—	17,555
Segment EBITDAX	138,339	(152)	—	138,187

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ("Quarterly Report") contains "forward-looking statements." All statements, other than statements of historical facts, included or incorporated by reference herein concerning, among other things, planned capital expenditures, increases in oil and gas production, the number of anticipated wells to be drilled or completed after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. For such statements, we claim the protection of the safe harbor for forward-looking statements contained in the Private Securities Litigation Reform Act of 1995. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- our ability to meet the financial covenants in our debt agreements and continue as a going concern;
- the success of our ongoing efforts to develop and implement a restructuring of our capital structure;
- federal and state regulations and laws;
- capital requirements and uncertainty of obtaining additional funding on terms acceptable to us;
- risks and restrictions related to our debt agreements;
- our ability to use derivative instruments to manage commodity price risk;
- realized oil, natural gas and NGL prices;
- a decline in oil, natural gas and NGL production, and the impact of general economic conditions on the demand for oil, natural gas and NGL and the availability of capital to oil and natural gas producers;
- asset impairments from commodity price declines;
- the outbreak of communicable diseases such as coronavirus;
- the willingness of the Organization of Petroleum Exporting Countries ("OPEC") and certain other oil and natural gas producing countries to set and maintain production levels;
- unsuccessful drilling and completion activities and the possibility of resulting write-downs;
- geographical concentration of our operations;
- constraints in the DJ Basin of Colorado with respect to gathering, transportation and processing facilities and marketing;
- lack of U.S. domestic storage;
- our ability to meet our proposed drilling schedule and to successfully drill wells that produce oil or natural gas in commercially viable quantities;
- shortages of oilfield equipment, supplies, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;
- adverse variations from estimates of reserves, production, production prices and expenditure requirements, and our inability to replace our reserves through exploration and development activities;
- incorrect estimates associated with properties we acquire relating to estimated proved reserves, the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs of such acquired properties;

- drilling operations associated with the employment of horizontal drilling techniques, and adverse weather and environmental conditions;
- limited control over non-operated properties;
- title defects to our properties and inability to retain our leases;
- our ability to successfully develop our large inventory of undeveloped operated and non-operated acreage;
- our ability to retain key members of our senior management and key technical employees;
- risks relating to managing our growth, particularly in connection with the integration of significant acquisitions;
- impact of environmental, health and safety, and other governmental regulations, and of current or pending legislation;
- risks associated with a material weakness in our internal control over financial reporting;
- changes in tax laws;
- effects of competition; and
- seasonal weather conditions.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas, and NGL that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers and management. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil, natural gas and NGL that are ultimately recovered.

In addition to the other information and risk factors set forth in this Quarterly Report, you should carefully consider the risk factors and other cautionary statements described under the heading “Risk Factors” included in our Annual Report on Form 10-K for the year ended December 31, 2019 (our “Annual Report”) and in our other filings with the Securities and Exchange Commission, which could materially affect our business, financial condition or future results. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. Other than as set forth in this Quarterly Report, there have been no material changes in our risk factors from those described in our Annual Report.

All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Quarterly Report. Except as required by law, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Management’s Discussion and Analysis of Financial Condition and Results of Operations (“MD&A”) is intended to provide the reader of the financial statements with a narrative from the perspective of management on the financial condition, results of operations, liquidity and certain other factors that may affect the Company’s operating results. MD&A should be read in conjunction with the Condensed Consolidated Financial Statements and related Notes included in Part I, Item 1 of this Quarterly Report. The following information updates the discussion of the Company’s financial condition provided in our Annual Report and analyzes the changes in the results of operations between the three months ended March 31, 2020 and 2019.

EXECUTIVE SUMMARY

We are an independent oil and gas company focused on the acquisition, development and production of oil, natural gas and NGL reserves, as well as the construction and support of midstream assets to gather and process crude oil and gas production in the Rocky Mountain region, primarily in the Wattenberg Field of the Denver-Julesburg Basin of Colorado. We have developed an oil, natural gas and NGL asset base of proved reserves, as well as a portfolio of development drilling opportunities on high resource-potential leasehold on contiguous acreage blocks in some of the

most productive areas of what we consider to be the core of the DJ Basin. We are focused on improving cash flow and our liquidity while reducing debt.

Financial Results

For the three months ended March 31, 2020, crude oil, natural gas and NGL sales, coupled with the impact of settled derivatives, increased to $204.5 million as compared to $202.0 million in the same prior year period due to an increase in sales volumes of approximately 1,341 MBoe, partially offset by a decrease of $4.25 in realized price per BOE, including settled derivatives.

For the three months ended March 31, 2020, we had net income of $9.0 million as compared to a net loss of $94.0 million for the three months ended March 31, 2019. The change to net income for the three months ended March 31, 2020 from net loss for the three months ended March 31, 2019 was primarily driven by an increase in commodity derivative gain of $385.1 million, partially offset by an increase in operating expenses of $112.0 million and a decrease in sales revenue of $56.7 million.

Adjusted EBITDAX was $123.9 million for the three months ended March 31, 2020 as compared to $138.2 million for the three months ended March 31, 2019, reflecting a 10.3% decrease. Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation to our most directly comparable financial measure calculated and presented in accordance with GAAP, please read "—Adjusted EBITDAX."

Operational Results

During the three months ended March 31, 2020, we focused on improving free cash flow and implemented operational efficiencies to reduce drilling and completion costs. We incurred approximately $146.6 million in drilling 34 gross (24.5 net) wells with an average lateral length of 2.3 miles and completing 28 gross (22.7 net) wells with an average lateral length of 2.3 miles, all of which were horizontal wells in the DJ Basin. In addition, we incurred approximately $8.8 million of leasehold and surface acreage additions.

Recent Developments

COVID-19 Outbreak and Global Industry Downturn

The recent worldwide outbreak in several countries, including the United States, of a highly transmissible and pathogenic coronavirus ("COVID-19") and the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19 have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. Decreased demand from much of the United States being on lockdown to prevent the spread of COVID-19 caused domestic storage capacity to begin to fill up during March and April causing further price declines and ultimately causing oil prices to plummet. We expect the excess supply of oil and natural gas in the United States to continue for a sustained period.

The COVID-19 outbreak and its development into a pandemic in March 2020 have required that we take precautionary measures intended to help minimize the risk to our business, employees, customers, suppliers and the communities in which we operate. Our operational employees are currently still able to work on site. However, we have taken various precautionary measures with respect to such operational employees such as requiring them to verify they have not experienced any symptoms consistent with COVID-19, or been in close contact with someone showing such symptoms, before reporting to the work site, quarantining any operational employees who have shown signs of COVID-19 (regardless of whether such employee has been confirmed to be infected) and imposing social distancing requirements on work sites, all in accordance with the guidelines released by the Center for Disease Control. In addition, most of our non-operational employees are now working remotely. We have not yet experienced any material operational disruptions (including disruptions from our suppliers and service providers) as a result of the COVID-19 outbreak, nor have we had any confirmed cases of COVID-19 on any of our work sites.

Due to the decline in crude oil prices and ongoing uncertainty regarding the oil supply-demand macro environment, we have recently reduced our operations in order to preserve capital. Specifically, we have renegotiated the terms of our drilling rig contracts as discussed in *Note 13—Commitments and Contingencies* in Part I, Item 1. Financial Information of this Quarterly Report.

In addition, given the weakness in realized oil prices, we are actively evaluating whether to voluntarily curtail or shut-in a substantial portion of our current production volumes and will continue to evaluate such a measure on a regular basis in response to market conditions and contractual obligations. As substantially all of our revenues are generated by the production and sale of hydrocarbons, the curtailment or shut-in of our production could adversely affect our business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures.

Please also see Part II, Item 1A in our Annual Report and in this Quarterly Report for further information related to these matters.

Deconsolidation of Elevation Midstream, LLC

Please see *Note 1—Business and Organization* in Part I, Item 1. Financial Information of this Quarterly Report for information related to the deconsolidation of Elevation Midstream, LLC.

Reduction in Workforce

We recorded involuntary termination charges of $5.8 million in the first quarter of 2020 primarily related to one-time involuntary termination benefits, office closure and relocation benefits communicated to our workforce in February 2020. This plan was initiated to align the size and composition of our workforce with our expected future operating and capital plans.

February 2020 Divestiture

In February 2020, we completed the sale of certain non-operated producing properties for aggregate sales proceeds of approximately $12.2 million, subject to customary purchase price adjustments. No gain or loss was recognized for the February 2020 Divestiture. We continue to explore divestitures as part of our ongoing initiative to divest non-strategic assets.

Elevation Common Units

On May 1, 2020, Elevation's board of managers issued 1,530,000,000 common units at a price of $0.01 per unit to certain of Elevation's members other than Extraction (the "Capital Raise"). The Capital Raise caused our ownership of Elevation to be diluted to less than 0.01%. As a result of the Capital Raise, beginning in May 2020 Extraction will account for Elevation under the cost method of accounting. We reserve all rights related to actions taken by Elevation’s board of managers.

Midstream Projects

Primarily due to the significant decrease in oil and gas prices during March 2020, Elevation postponed indefinitely further development of gathering systems and facilities that were to be constructed to service our acreage in Hawkeye and another project in the Southwest Wattenberg area.

Senate Bill 19-181 "Protect Public Welfare Oil and Gas Operations"

In April 2019, Senate Bill 19-181 ("SB181") became law, increasing the regulatory authority of local governments in Colorado over the surface impacts of oil and gas development in a reasonable manner, and in December 2019, Colorado's Air Quality Control Commission ("AQCC") adopted new rules targeting air emissions from upstream oil and gas operation. Among other things, SB181 (i) repeals a prior law restricting local government land use authority over oil and gas mineral extraction areas to areas designated by the COGCC, (ii) directs the AQCC to review its leak detection and repair rules and to adopt rules to minimize emissions of certain air pollutants, (iii) clarifies that local governments have authority to regulate the siting of oil and gas locations in a reasonable manner, including the ability to inspect oil and gas facilities, impose fines for leaks, spills, and emissions, and impose fees on operators or owners to cover regulation and enforcement costs, (iv) allows local governments or oil and gas operators to request a technical review board to evaluate the effect of the local government's preliminary or final determination on the operator's application, (v) repeals an exemption for oil and gas production from counties' authority to regulate noise, (vi) alters forced pooling requirements by increasing the threshold to compel non-consenting individuals into statutory pooling agreements and (vii) elevates the protection of public health, safety, and welfare, the environment, and wildlife resources in the regulation of oil and gas development. Although industry trade associations opposed SB181, management believes that Extraction can continue to successfully operate our business. However, the enactment of SB181 and the development and implementation of related rules and regulations, which is under way, could lead to delays and additional costs to our business. For example, COGCC rulemaking on flowline safety (completed on November 21, 2019) and the Colorado AQCC and Air Pollution Control Division ("APCD") rulemaking on air quality standards (completed December 20, 2019) – both pursuant to SB181 – could lead to such delays or costs. Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various alternatives for ballot initiatives which would result in significantly limiting or preventing oil and natural gas development in the state. Proponents of such initiatives have begun the process of attempting to qualify several initiatives to appear on the ballot in November 2020.

Going Concern

Please see *Note 4—Going Concern* in Part I, Item 1. Financial Information and "Risk Factors" in Part II, Item 1A of this Quarterly Report, as well as "—Liquidity and Capital Resources" below.

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and gas operations, including:

- Sources of revenue;
- Sales volumes;
- Realized prices on the sale of oil, natural gas and NGL, including the effect of our commodity derivative contracts;
- Lease operating expenses ("LOE");
- Capital expenditures;
- Adjusted EBITDAX (a Non-GAAP measure); and
- Free cash flow (a Non-GAAP measure).

Sources of Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil, natural gas and NGL revenues do not include the effects of derivatives. For the three months ended March 31, 2020, our revenues were derived 75% from oil sales, 14% from natural gas sales and 11% from NGL sales. For the three months ended March 31, 2019, our revenues were derived 75% from oil sales, 16% from natural gas sales and 9% from NGL sales. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Sales Volumes

The following table presents historical sales volumes for the periods indicated:

	For the Three Months Ended March 31,	
	2020	**2019**
Oil (MBbl)	3,504	3,583
Natural gas (MMcf)	19,003	13,959
NGL (MBbl)	1,906	1,327
Total (MBoe)	8,576	7,236
Average net sales (BOE/d)	94,247	80,401

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add or develop proved reserves in excess of our production. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including takeaway capacity in our areas of operation and our ability to raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read "Risks Related to the Oil, Natural Gas and NGL Industry and Our Business" in Item 1A. of our Annual Report for a further description of the risks that affect us.

Realized Prices on the Sale of Oil, Natural Gas and NGL

Our results of operations depend upon many factors, particularly the price of oil, natural gas and NGL and our ability to market our production effectively. Oil, natural gas and NGL prices are among the most volatile of all commodity prices. For example, during the period from January 1, 2014 to March 31, 2020, NYMEX West Texas Intermediate oil prices ranged from a high of $107.26 per Bbl to a low of $20.09 per Bbl. Average daily prices for NYMEX Henry Hub gas ranged from a high of $6.15 per MMBtu to a low of $1.60 per MMBtu during the same period. Declines in, and continued depression of, the price of oil and natural gas occurring during 2015, 2019 and 2020 are due to a combination of factors including increased U.S. supply, global economic concerns stemming from COVID-19 and the price war between Russia and Saudi Arabia. These price variations can have a material impact on our financial results and capital expenditures.

Oil pricing is predominantly driven by the physical market, supply and demand, financial markets and national and international politics. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. In the DJ Basin, oil is sold under various purchase contracts with monthly pricing provisions based on NYMEX pricing, adjusted for differentials.

Natural gas prices vary by region and locality, depending upon the distance to markets, availability of pipeline capacity and supply and demand relationships in that region or locality. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, wet natural gas with a high Btu content sells at a premium to low Btu content dry natural gas because it yields a greater quantity of NGL. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant, generally in the form of percentage of proceeds. The price we receive for our natural gas produced in the DJ Basin is based on CIG prices, adjusted for certain deductions.

Our price for NGL produced in the DJ Basin is based on a combination of prices from the Conway hub in Kansas and Mont Belvieu in Texas where this production is marketed.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil, natural gas and NGL normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, as applicable.

	For the Three Months Ended March 31,	
	2020	2019
Oil		
NYMEX WTI High ($/Bbl)	$ 63.27	$ 60.14
NYMEX WTI Low ($/Bbl)	$ 20.09	$ 46.54
NYMEX WTI Average ($/Bbl)	$ 45.78	$ 54.90
Average Realized Price ($/Bbl)[1]	$ 35.45	$ 46.17
Average Realized Price, with derivative settlements ($/Bbl)[1]	$ 45.50	$ 41.89
Average Realized Price as a % of Average NYMEX WTI	77.4 %	84.1 %
Differential ($/Bbl) to Average NYMEX WTI[2]	$ (7.91)	$ (8.73)
Natural Gas		
NYMEX Henry Hub High ($/MMBtu)	$ 2.20	$ 3.59
NYMEX Henry Hub Low ($/MMBtu)	$ 1.60	$ 2.55
NYMEX Henry Hub Average ($/MMBtu)	$ 1.87	$ 2.87
NYMEX Henry Hub Average converted to a $/Mcf basis[3]	$ 2.06	$ 3.16
Average Realized Price ($/Mcf)	$ 1.17	$ 2.57
Average Realized Price, with derivative settlements ($/Mcf)	$ 1.39	$ 2.25
Average Realized Price as a % of Average NYMEX Henry Hub[3]	56.8 %	81.3 %
Differential ($/Mcf) to Average NYMEX Henry Hub[3]	$ (0.89)	$ (0.59)
NGL		
Average Realized Price ($/Bbl)[4]	$ 9.02	$ 15.53
Average Realized Price as a % of Average NYMEX WTI	19.7 %	28.3 %
BOE		
Average Realized Price per BOE	$ 19.09	$ 30.67
Average Realized Price per BOE with derivative settlements	$ 23.67	$ 27.92

(1) Includes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the three months ended March 31, 2020, pursuant to ASC 606, Revenue Recognition.
(2) Excludes non-cash amounts allocated to a satisfied performance obligation, recognized within oil sales for the three months ended March 31, 2020, pursuant to ASC 606, Revenue Recognition.
(3) Based on the difference between our average realized price and the NYMEX Henry Hub Average as converted into Mcf using a conversion factor of 1.1 to 1.
(4) The decrease year over year is primarily due to capacity constraints in transporting the wet gas associated with our production coupled with negative market conditions surrounding limited export capacity.

Derivative Arrangements

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in commodity prices, from time to time, we enter into derivative arrangements for our oil and natural gas production. By removing a significant portion of price volatility associated with our oil and natural gas production, we believe we will mitigate, but not eliminate, the potential negative effects of reductions in oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, our hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our derivative portfolio, we may choose to restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. See "—Quantitative and Qualitative Disclosure About Market

Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. As a result of recent volatility in the price of oil and natural gas, we have relied on a variety of hedging strategies and instruments to hedge our future price risk. We have utilized swaps, put options and call options, which in some instances require the payment of a premium, to reduce the effect of price changes on a portion of our future oil and natural gas production. We expect to continue to use a variety of hedging strategies and instruments for the foreseeable future.

A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

A put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless. Some of our purchased put options have deferred premiums. For the deferred premium puts, we agreed to pay a premium to the counterparty at the time of settlement.

A call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

We combine swaps, purchased put options, sold put options, and sold call options in order to achieve various hedging strategies. Some examples of our hedging strategies are collars which include purchased put options and sold call options, three-way collars which include purchased put options, sold put options, and sold call options, and enhanced swaps, which include either sold put options or sold call options with the associated premiums rolled into an enhanced fixed price swap. We have historically relied on commodity derivative contracts to mitigate our exposure to lower commodity prices.

We have historically been able to hedge our oil and natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements at favorable prices may be limited, and, we are not obligated to hedge a specific portion of our oil or natural gas production.

For a description of our derivative instruments that we utilize and a summary of our commodity derivative contracts as of March 31, 2020, please see *Note 6—Commodity Derivative Instruments* in Part I, Item 1. Financial Information of this Quarterly Report.

The following table summarizes our historical derivative positions and the settlement amounts for each of the periods indicated.

	For the Three Months Ended March 31,	
	2020	**2019**
NYMEX WTI Crude Swaps:		
Notional volume (Bbl)	225,000	1,350,000
Weighted average fixed price ($/Bbl)	$ 60.13	$ 54.58
NYMEX WTI Crude Purchased Puts:		
Notional volume (Bbl)	3,650,000	4,725,000
Weighted average purchased put price ($/Bbl)	$ 54.79	$ 46.05
NYMEX WTI Crude Purchased Calls:		
Notional volume (Bbl)	600,000	5,100,000
Weighted average purchased call price ($/Bbl)	$ 68.05	$ 63.40
NYMEX WTI Crude Sold Calls:		
Notional volume (Bbl)	3,650,000	6,600,000

Weighted average sold call price ($/Bbl)	$	63.34	$	62.17
NYMEX WTI Crude Sold Puts:				
Notional volume (Bbl)		3,700,000		4,200,000
Weighted average sold put price ($/Bbl)	$	44.01	$	43.35
NYMEX HH Natural Gas Swaps:				
Notional volume (MMBtu)		8,400,000		5,400,000
Weighted average fixed price ($/MMBtu)	$	2.76	$	3.11
NYMEX HH Natural Gas Purchased Puts:				
Notional volume (MMBtu)		600,000		3,600,000
Weighted average purchased put price ($/MMBtu)	$	2.90	$	3.04
NYMEX HH Natural Gas Sold Calls:				
Notional volume (MMBtu)		600,000		3,600,000
Weighted average sold call price ($/MMBtu)	$	3.48	$	3.46
NYMEX HH Natural Gas Sold Puts:				
Notional volume (MMBtu)		—		3,000,000
Weighted average sold put price ($/MMBtu)	$	—	$	2.50
CIG Basis Gas Swaps:				
Notional volume (MMBtu)		11,400,000		9,400,000
Weighted average fixed basis price ($/MMBtu)	$	(0.61)	$	(0.75)
Total Amounts Received/(Paid) from Settlement (in thousands)	$	39,295	$	(10,329)
Cash provided by changes in Accounts Receivable and Accounts Payable related to Commodity Derivatives	$	(14,363)	$	6,791
Cash Settlements on Commodity Derivatives per Condensed Consolidated Statements of Cash Flows	$	24,932	$	(3,538)

Lease Operating Expenses

All direct and allocated indirect costs of lifting hydrocarbons from a producing formation to the surface constitutes part of the current operating expenses of a working interest. Such costs include labor, superintendence, supplies, repairs, maintenance, water injection and disposal costs, allocated overhead charges, workover, insurance and other expenses incidental to production, but exclude lease acquisition or drilling or completion expenses.

Capital Expenditures

For the three months ended March 31, 2020, we incurred approximately $146.6 million in drilling and completion capital expenditures. For the three months ended March 31, 2020, we drilled 34 gross (24.5 net) wells with an average lateral length of approximately 2.3 miles and completed 28 gross (22.7 net) wells with an average lateral length of approximately 2.3 miles. We turned to sales 13 gross (12 net) wells with an average lateral length of approximately 2.1 miles. In addition, we incurred approximately $8.8 million of leasehold and surface acreage additions.

The amount and timing of these capital expenditures is within our control and subject to our management's discretion. We retain the flexibility to defer a portion of these planned capital expenditures depending on a variety of factors, including but not limited to the success of our drilling activities, prevailing and anticipated prices for oil, natural gas and NGL, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other interest owners. Any postponement or elimination of our development drilling program could result in a reduction of proved reserve volumes and related standardized measure. These risks could materially affect our business, financial condition and results of operations.

Adjusted EBITDAX

Adjusted EBITDAX is not a measure of net income (loss) as determined by United States GAAP. Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We define Adjusted EBITDAX as net income (loss) adjusted for certain cash and non-cash items, including depletion, depreciation, amortization and

accretion (DD&A), impairment of long lived assets, non-recurring charges in other operating expenses, exploration and abandonment expenses, gain on sale of property and equipment, (gain) loss on commodity derivatives, settlements on commodity derivative instruments, premiums paid for derivatives that settled during the period, stock-based compensation expense, amortization of debt issuance costs, gain on repurchase of senior notes, interest expense, income tax expense (benefit) and loss on deconsolidation of Elevation Midstream, LLC. Adjusted EBITDAX is also used to evaluate the performance of reportable segments. Please see *Note 15—Segment Information* in Part I, Item 1. Financial Information of this Quarterly Report for more information regarding the EBITDAX of reportable segments.

Management believes Adjusted EBITDAX is useful because it allows us to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income (loss) as determined in accordance with GAAP or as an indicator of our operating performance. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital, hedging strategy and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measure of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance. Additionally, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure (i) is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, among other factors; (ii) helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and (iii) is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting.

The following table presents a reconciliation of Adjusted EBITDAX to the GAAP financial measure of net income (loss) for each of the periods indicated (in thousands).

	For the Three Months Ended March 31,	
	2020	2019
Reconciliation of Net Income (Loss) to Adjusted EBITDAX:		
Net income (loss)	$ 9,037	$ (94,032)
Add back:		
Depletion, depreciation, amortization and accretion	76,051	118,770
Impairment of long lived assets	775	8,248
Other operating expenses	52,575	—
Exploration and abandonment expenses	112,480	6,194
Gain on sale of property and equipment	—	(222)
(Gain) loss on commodity derivatives	(263,015)	122,091
Settlements on commodity derivative instruments	39,295	(10,329)
Premiums paid for derivatives that settled during the period	—	(9,549)
Stock-based compensation expense	—	13,008
Amortization of debt issuance costs	1,242	1,497
Gain on repurchase of 2026 Senior Notes	—	(7,317)
Interest expense	20,116	18,828
Income tax expense (benefit)	2,200	(29,000)
Loss on deconsolidation of Elevation Midstream, LLC	73,139	—
Adjusted EBITDAX	$ 123,895	$ 138,187

Free Cash Flow

Our Free Cash Flow is not a measure of net income (loss) as determined by GAAP. We define Free Cash Flow as Discretionary Cash Flow (non-GAAP) less Adjusted Cash Flow used in Investing (non-GAAP) adjusted for Other Non-Recurring Adjustments (non-GAAP). Discretionary Cash Flow is defined as net cash provided by operating activities (GAAP) less changes in working capital (current assets and liabilities). Adjusted Cash Flow used in Investing is defined as cash flow used in investing activities (GAAP) adjusted for changes in accounts payable and accrued liabilities related to capital expenditures.

Free Cash Flow is used by management and external users of our financial statements, such as industry analysts, investors, lenders and rating agencies. We believe Free Cash Flow can provide additional transparency into the drivers of trends in our operating cash flows, such as production, realized sales prices and operating costs, as it disregards the timing of settlement of operating assets and liabilities. We believe Free Cash Flow provides additional information that may be useful in an analysis of our ability to generate cash to fund exploration and development activities, construct and support midstream assets, and to return capital to stockholders.

The following tables present a reconciliation of Discretionary Cash Flow and Free Cash Flow to the GAAP financial measure of net cash provided by operating activities for each of the periods indicated.

	Upstream	Midstream	Consolidated
	For the Three Months Ended March 31, 2020		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 144,219	$ 2,880	$ 147,099
Changes in current assets and liabilities	(101,047)	(1,907)	(102,954)
Discretionary Cash Flow	43,172	973	44,145
Cash Flow from Investing Activities			
Net cash used in investing activities	(133,863)	(5,840)	(139,703)
Change in accounts payable and accrued liabilities related to capital expenditures	(10,477)	2,210	(8,267)
Adjusted Cash Flow used in Investing	(144,340)	(3,630)	(147,970)
Other Non-Recurring Adjustments[1]	1,170	—	1,170
Free Cash Flow	$ (99,998)	$ (2,657)	$ (102,655)

	Upstream	Midstream	Consolidated
	For the Three Months Ended March 31, 2019		
Cash Flow from Operating Activities			
Net cash provided by operating activities	$ 131,121	$ 2,990	$ 134,111
Changes in current assets and liabilities	3,634	(447)	3,187
Discretionary Cash Flow	134,755	2,543	137,298
Cash Flow from Investing Activities			
Net cash used in investing activities	(184,719)	(47,656)	(232,375)
Change in accounts payable and accrued liabilities related to capital expenditures	8,350	(9,566)	(1,216)
Adjusted Cash Flow used in Investing	(176,369)	(57,222)	(233,591)
Other Non-Recurring Adjustments[1]	1,582	—	1,582
Free Cash Flow	$ (40,032)	$ (54,679)	$ (94,711)

(1) Amount incurred for the construction of our field office that is included in other property and equipment in our condensed consolidated statements of cash flows.

Items Affecting the Comparability of Our Financial Results

Our historical results of operations for the periods presented may not be comparable, either to each other or to our future results of operations, for the reasons described below:

- For the three months ended March 31, 2020 and 2019, respectively, exploration and abandonment expenses increased primarily due to the abandonment of $106.9 million and $3.9 million of unproved properties.
- Elevation Midstream, LLC was deconsolidated as of March 16, 2020 and accounted for as an equity method investment. We elected the fair value option to remeasure the Elevation Midstream, LLC equity method investment and determined it had no fair value. We recorded a $73.1 million loss on deconsolidation of Elevation Midstream, LLC in the condensed consolidated statements of operations for the three months ended March 31, 2020. Please see *Note 1—Business and Organization* in Part I, Item 1. Financial Information of this Quarterly Report for information related to the deconsolidation of Elevation Midstream, LLC.
- On April 2, 2020, Elevation demanded payment of $46.8 million due to an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering facility prior to April 1, 2020. While the Company disputes that these amounts are due to Elevation, under ASC *Topic 450 - Contingencies*, we recorded the amount in other operating expenses on the condensed consolidated statements of operations for the three months ended March 31, 2020.

Historical Results of Operations and Operating Expenses

Oil, Natural Gas and NGL Sales Revenues, Operating Expenses and Other Income (Expense).

For components of our revenues, operating expenses, other income (expense) and net income (loss), please see our condensed consolidated statements of operations in Part I, Item 1. Financial Information of this Quarterly Report.

The following table provides a summary of our sales volumes, average prices and operating expenses on a per BOE basis for the periods indicated:

	For the Three Months Ended March 31,	
	2020	**2019**
Sales (MBoe)[1]:	8,576	7,236
Oil sales (MBbl)	3,504	3,583
Natural gas sales (MMcf)	19,003	13,959
NGL sales (MBbl)	1,906	1,327
Sales (BOE/d)[1]:	94,247	80,401
Oil sales (Bbl/d)	38,502	39,809
Natural gas sales (Mcf/d)	208,819	155,103
NGL sales (Bbl/d)	20,942	14,742
Average sales prices[2]:		
Oil sales (per Bbl)[3]	$ 35.45	$ 46.17
Oil sales with derivative settlements (per Bbl)[3]	45.50	41.89
Natural gas sales (per Mcf)	1.17	2.57
Natural gas sales with derivative settlements (per Mcf)	1.39	2.25
NGL sales (per Bbl)	9.02	15.53
Average price (per BOE)[3]	19.09	30.67
Average price with derivative settlements (per BOE)[3]	23.67	27.92
Expense per BOE:		
Lease operating expenses	$ 3.54	$ 3.02
Transportation and gathering	2.66	1.43
Production taxes	1.57	2.51
Exploration and abandonment expenses	13.11	0.86
Depletion, depreciation, amortization and accretion	8.87	16.41
General and administrative expenses	1.24	3.82
Cash general and administrative expenses[4]	1.24	2.02
Stock-based compensation	—	1.80
Total operating expenses per BOE[5]	$ 30.99	$ 28.05
Production taxes as a percentage of revenue	8.1 %	8.2 %

(1) One BOE is equal to six Mcf of natural gas or one Bbl of oil or NGL based on an approximate energy equivalency. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

(2) Average prices shown in the table reflect prices both before and after the effects of our settlements of commodity derivative contracts. Our calculation of such effects includes both gains and losses on settlements for commodity derivatives and amortization of premiums paid or received on options that settled during the period.

(3) Includes amounts allocated to a satisfied performance obligation, recognized within oil sales for the three months ended March 31, 2020, pursuant to ASC 606, Revenue Recognition.

(4) Cash general and administrative expenses for the three months ended March 31, 2020 includes expense of $2.2 million related to the terms of a separation agreement with a former executive officer. Excluding this one-time expense results in cash general and administrative expense per BOE of $0.97 for the three months ended March 31, 2020.

(5) Excludes midstream operating expenses, impairment of long lived assets, gain on sale of property and equipment, and other operating expenses.

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019

Oil sales revenues. Crude oil sales revenues decreased by $41.2 million to $124.2 million for the three months ended March 31, 2020 as compared to crude oil sales of $165.4 million for the three months ended March 31, 2019. A decrease in sales volumes between these periods contributed a $3.7 million negative impact, and a decrease in crude oil prices contributed a $37.5 million negative impact. For the three months ended March 31, 2020, crude oil revenue decreased by approximately $8.5 million due to the impact of the increase in the forecasted deferral balance on one of our revenue contracts. Pursuant to ASC 606, the contract term impacts the amount of consideration that can be included in the transaction price, which reduced oil sales revenue.

For the three months ended March 31, 2020, our crude oil sales averaged 38.5 MBbl/d. Our crude oil sales volume decreased by 0.1 to 3.5 MBbl for the three months ended March 31, 2020 compared to 3.6 MBbl for the three months ended March 31, 2019. The volume decrease is primarily due to the natural decline of our existing properties, partially offset by an increase in production from the completion of 28 gross wells from January 1, 2020 to March 31, 2020.

The average price we realized on the sale of crude oil was $35.45 per Bbl for the three months ended March 31, 2020 compared to $46.17 per Bbl for the three months ended March 31, 2019, primarily due to changes in market prices for crude oil and the $8.5 million decrease of crude oil revenue explained above.

Natural gas sales revenues. Natural gas sales revenues decreased by $13.6 million to $22.3 million for the three months ended March 31, 2020 as compared to natural gas sales revenues of $35.9 million for the three months ended March 31, 2019. An increase in sales volumes between these periods contributed a $13.0 million positive impact, while a decrease in natural gas prices contributed a $26.6 million negative impact.

For the three months ended March 31, 2020, our natural gas sales averaged 208.8 MMcf/d. Natural gas sales volumes increased by 5.0 to 19.0 MMcf for the three months ended March 31, 2020 as compared to 14.0 MMcf for the three months ended March 31, 2019. The volume increase is primarily due to the completion of 28 gross wells from January 1, 2020 to March 31, 2020, partially offset by the natural decline on existing producing properties.

The average price we realized on the sale of our natural gas was $1.17 per Mcf for the three months ended March 31, 2020 compared to $2.57 per Mcf for the three months ended March 31, 2019, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

NGL sales revenues. NGL sales revenues decreased by $3.4 million to $17.2 million for the three months ended March 31, 2020 as compared to NGL sales revenues of $20.6 million for the three months ended March 31, 2019. An increase in sales volumes between these periods contributed a $8.9 million positive impact, while a decrease in price contributed a $12.3 million negative impact.

For the three months ended March 31, 2020, our NGL sales averaged 20.9 MBbl/d. NGL sales volumes increased by 0.6 to 1.9 MBbl for the three months ended March 31, 2020 as compared to 1.3 MBbl for the three months ended March 31, 2019. The volume increase is primarily due to the completion of 28 gross wells during the three months ended March 31, 2020, partially offset by the natural decline on existing producing properties. Our NGL sales are directly associated with our natural gas sales because our natural gas volumes are processed by third parties for both residue natural gas sales and NGL sales.

The average price we realized on the sale of our NGL was $9.02 per Bbl for the three months ended March 31, 2020 compared to $15.53 per Bbl for the three months ended March 31, 2019, primarily due to capacity constraints in transporting the wet gas associated with crude oil production coupled with negative market conditions surrounding limited export capacity.

Lease operating expenses. Our LOE increased by $8.5 million to $30.4 million for the three months ended March 31, 2020, from $21.9 million for the three months ended March 31, 2019. The increase in LOE was primarily the result of an increase in producing wells and an increase in workover repairs, partially offset by optimization of our field cost structure during the three months ended March 31, 2020. On a per unit basis, LOE increased to $3.54 per BOE sold for the three months ended March 31, 2020 from $3.02 per BOE for the three months ended March 31, 2019.

Transportation and gathering ("T&G"). Our T&G expense increased by $12.4 million to $22.8 million for the three months ended March 31, 2020, from $10.4 million for the three months ended March 31, 2019. The increase in T&G was primarily due to an increase of volumes on a certain gathering system during the three months ended March 31, 2020 compared to the three months ended March 31, 2019. On a per unit basis, T&G increased to $2.66 per BOE sold for the three months ended March 31, 2020 compared to $1.43 per BOE sold for the three months ended March 31, 2019.

Production taxes. Our production taxes decreased by $4.6 million to $13.5 million for the three months ended March 31, 2020 as compared to $18.1 million for the three months ended March 31, 2019. The decrease is primarily attributable to decreased revenue as production taxes are calculated as a percentage of sales revenue. Production taxes as a percentage of sales revenue was 8.1% for the three months ended March 31, 2020 as compared to 8.2% for the three months ended March 31, 2019. The consistency in production taxes as a percentage of sales revenue relates to comparatively constant estimated ad valorem and severance tax rates for the three months ended March 31, 2020.

Exploration and abandonment expenses. Our exploration and abandonment expenses were $112.5 million for the three months ended March 31, 2020, of which $106.9 million was lease abandonment expense. Due to the decrease in pricing, all of the unproved property in our northern field was abandoned and impaired. For the three months ended March 31, 2019, we recognized $6.2 million in exploration and abandonment expenses.

Depletion, depreciation, amortization and accretion expense. Our DD&A expense decreased $42.7 million to $76.1 million for the three months ended March 31, 2020 as compared to $118.8 million for the three months ended March 31, 2019. On a per unit basis, DD&A expense decreased to $8.87 per BOE for the three months ended March 31, 2020 from $16.41 per BOE for the three months ended March 31, 2019. This decrease is due to an impairment of $1.3 billion of proved oil and gas properties that occurred during the fourth quarter of 2019.

Impairment of long lived assets. For the three months ended March 31, 2020 and 2019, impairment expense was $0.8 million and $8.2 million, respectively, related to impairment of the proved oil and gas properties in our northern field as the fair value did not exceed the carrying amount associated with the properties.

General and administrative expenses ("G&A"). General and administrative expenses decreased by $17.1 million to $10.6 million for the three months ended March 31, 2020 as compared to $27.7 million for the three months ended March 31, 2019. This decrease is primarily due to a one-time reduction of workforce during the first quarter of 2020, and a decrease in stock-based compensation expense recognized for the three months ended March 31, 2020 compared to the three months ended March 31, 2019. On a per unit basis, G&A expense decreased to $1.24 per BOE sold for the three months ended March 31, 2020 from $3.82 per BOE sold for the three months ended March 31, 2019.

Our G&A expenses for the three months ended March 31, 2020 includes $2.2 million related to the terms of a separation agreement with a former executive officer. No expenses of this nature were incurred during the three months ended March 31, 2019.

Our G&A expenses include the non-cash expense for stock-based compensation for equity awards granted to our employees and directors. For the three months ended March 31, 2020, there was no stock-based compensation expense primarily as a result of a true-up related to forfeitures in connection with the workforce reduction in February 2020. For the three months ended March 31, 2019, stock-based compensation expense was $13.0 million.

Other operating expenses. Other operating expenses were $52.6 million for the three months ended March 31, 2020. This amount is primarily made up of a $46.8 million loss contingency from an alleged breach in contract stemming from a purported failure to complete the pipeline extensions connecting certain wells to the Badger central gathering

facility prior to April 1, 2020. Also included in this amount is a $5.8 million charge to income for expenses related to a workforce reduction in February 2020.

Commodity derivative gain (loss). Primarily due to the decrease in NYMEX crude oil futures prices at March 31, 2020 as compared to December 31, 2019 and change in fair value from the execution of new positions, we incurred a net gain on our commodity derivatives of $263.0 million for the three months ended March 31, 2020. Primarily due to the increase in NYMEX crude oil futures prices at March 31, 2019 as compared to December 31, 2018 and change in fair value from the execution of new positions, we incurred a net loss on our commodity derivatives of $122.1 million for the three months ended March 31, 2019, including the amortization of premiums. These gains and losses are a result of our hedging program, which is used to mitigate our exposure to commodity price fluctuations. The fair value of the open commodity derivative instruments will continue to change in value until the transactions are settled and we will likely add to our hedging program in the future. Therefore, we expect our net income (loss) to reflect the volatility of commodity price forward markets. Our cash flow will only be affected upon settlement of the transactions at the current market prices at that time. During the three months ended March 31, 2020, we received cash settlements of commodity derivatives totaling $39.3 million. During the three months ended March 31, 2019, we paid settlements of commodity derivatives totaling $10.3 million.

Loss on deconsolidation of Elevation Midstream, LLC. On March 16, 2020, we deconsolidated Elevation Midstream, LLC. Upon deconsolidation, we elected the fair value option to remeasure the Elevation equity method investment and determined it had no fair value. The Company recorded a $73.1 million loss on deconsolidation of Elevation Midstream, LLC in the condensed consolidated statements of operations for the three months ended March 31, 2020.

Interest expense. Interest expense consists of interest expense on our long-term debt and amortization of debt issuance costs, net of capitalized interest. For the three months ended March 31, 2020, we recognized interest expense of $21.4 million as compared to $13.0 million for the three months ended March 31, 2019, as a result of borrowings under our revolving credit facility, our 2024 Senior Notes, our 2026 Senior Notes and the amortization of debt issuance costs.

We incurred interest expense for the three months ended March 31, 2020 of $22.3 million related to our 2024 Senior Notes, 2026 Senior Notes, and revolving credit facility. We incurred interest expense for the three months ended March 31, 2019 of approximately $20.8 million related to our revolving credit facility, our 2024 Senior Notes, and our 2026 Senior Notes. Also included in interest expense for the three months ended March 31, 2020 and 2019 was the amortization of debt issuance costs of $1.2 million and $1.5 million, respectively. For the three months ended March 31, 2020 and 2019, we capitalized interest expense of $2.1 million and $2.0 million, respectively. Interest expense for the three months ended March 31, 2019 also includes $7.3 million of gain on debt extinguishment upon the repurchase of our 2026 Senior Notes.

Income tax (expense) benefit. We recorded an income tax expense and benefit of $2.2 million and $29.0 million, respectively, for the three months ended March 31, 2020 and 2019, respectively. This resulted in an effective tax rate of approximately 19.6% and 23.6% for the three months ended March 31, 2020 and 2019, respectively. Our effective tax rate for the three months ended March 31, 2020 and 2019 differs from the U.S. statutory income tax rates of 21.0% primarily due to the effects of state income taxes, estimated taxable permanent differences, and valuation allowance.

Gathering and facilities segment. Prior to March 31, 2020, we had two operating segments, (i) the exploration, development and production of oil, natural gas and NGL (the "exploration and production segment") and (ii) the construction, operation and support of midstream assets to gather and process crude oil and gas production (the "gathering and facilities segment"). Please see *Note 1—Business and Organization* in Part I, Item I, Financial Information of this Quarterly Report for further information related to the deconsolidation of Elevation Midstream, LLC. After March 31, 2020, Extraction will report as a single operating segment.

In October 2019, Elevation commenced moving crude oil, natural gas and water through its Badger central gathering facility. Because Elevation had no revenue and insignificant operating expenses for the three months ended March 31, 2019, comparison to the three months ended March 31, 2020 is not relevant. For the three months ending March 31, 2020, our gathering and facilities segment had revenues of $5.9 million and direct operating expenses of $3.9

million. General and administrative expenses were $1.1 million for both of the three months ended March 31, 2020 and 2019. For the three months ended March 31, 2020, depreciation expense was $1.1 million as the gathering facility was placed into service during the fourth quarter of 2019. Please see *Note 15—Segments* in Part I, Item I, Financial Information of this Quarterly Report.

Liquidity and Capital Resources

Current Financial Condition and Liquidity

The market price for oil, natural gas and NGLs decreased significantly beginning in the first quarter of 2020, continuing into the second quarter of 2020. The decrease in the market price for our production directly reduces our cash flow from operations and indirectly impacts other potential sources of funds described above. Our ability to continue as a going concern is dependent upon attaining and maintaining profitable operations and, until that time, raising additional capital as needed, but there can be no assurance that we will be able to raise sufficient financing on terms that are acceptable to us, or at all. As discussed in *Note 4—Going Concern* in Part I, Item I, Financial Information of this Quarterly Report, on April 27, 2020 the lenders under the revolving credit facility elected to reduce the borrowing base and elected commitments to $650.0 million from $950.0 million, and we borrowed all of the remaining available capacity under the revolving credit facility. As a result of the reduction of the borrowing base and elected commitments, it is probable that we will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 when assuming our current financial forecast.

We may seek covenant relief from the lenders under the revolving credit facility, and if we do not obtain a waiver of financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to declare all outstanding principal and interest to be due and payable, and the lenders under the credit agreement could terminate their commitments to loan money and could foreclose against the assets collateralizing their borrowings. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of our other outstanding long-term debt. These potential defaults create uncertainty associated with our ability to repay outstanding long-term debt obligations as they become due and creates a substantial doubt over our ability to continue as a going concern.

As a result of the impacts to our financial position resulting from declining commodity price conditions and in consideration of the substantial amount of long-term debt and preferred stock outstanding, we have engaged advisors to assist with the evaluation of strategic alternatives, which may include, but not be limited to, seeking a restructuring, amendment or refinancing of existing debt through a private restructuring or reorganization under Chapter 11 of the Bankruptcy Code. However, there can be no assurances that we will be able to successfully restructure our indebtedness, improve our financial position or complete any strategic transactions. As a result of these uncertainties and the likelihood of a restructuring or reorganization, management has concluded that there is substantial doubt regarding our ability to continue as a going concern.

Sources of Liquidity and Capital Resources

Historically, our primary sources of liquidity have been borrowings under our revolving credit facility, proceeds from notes offerings and preferred stock offerings, equity provided by investors, including our management team, cash from issuance of preferred stock, and cash flows from divestitures and from the sale of oil, gas and NGL production. Our primary uses of capital have been for the acquisition of oil and gas properties to increase our acreage position, as well as development and exploration of oil and gas properties. Our borrowings, net of unamortized debt issuance costs, were approximately $1,556.3 million and $1,555.8 million at March 31, 2020, and December 31, 2019, respectively. We also have other contractual commitments, which are described in *Note 13—Commitments and Contingencies* in Part I, Item 1, Financial Information of this Quarterly Report.

We may from time to time seek to retire or purchase our outstanding notes through cash purchases and/or exchanges (including for equity securities), in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we intend to enter into commodity derivative contracts at times and on terms desired to maintain a portfolio of commodity derivative contracts covering approximately 50% to 70% of our projected oil and natural gas production over a one to two year period at a given point in time, although we may from time to time hedge more or less than this approximate range.

If cash flow from operations does not meet our expectations, we may further reduce our expected level of capital expenditures and/or fund a portion of our capital expenditures using borrowings under our revolving credit facility, issuances of debt and equity securities or from other sources, such as asset sales. We cannot assure you that necessary capital will be available on acceptable terms or at all. Our ability to raise funds through the incurrence of additional indebtedness could be limited by the covenants in our debt arrangements. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

We had a Stock Repurchase Program that ended in 2019. During the three months ended March 31, 2019. Spending under this program was $60.0 million. We also have a Senior Notes Repurchase Program in place. Spending under this program during the three months ended March 31, 2019 was $28.5 million. No Senior Notes were repurchased during the three months ended March 31, 2020. We are authorized to repurchase up to $100.0 million of our Senior Notes.

Cash Flows

The following table summarizes our cash flows for the periods indicated (in thousands):

	For the Three Months Ended March 31,	
	2020	**2019**
Net cash provided by operating activities	$ 147,099	$ 134,111
Net cash used in investing activities	$ (139,703)	$ (232,375)
Net cash used in financing activities	$ (57)	$ (23,951)

Three Months Ended March 31, 2020 Compared to Three Months Ended March 31, 2019

Net cash provided by operating activities. For the three months ended March 31, 2020 as compared to the three months ended March 31, 2019, our net cash provided by operating activities increased by $13.0 million, primarily due to an increase of $59.4 million related to changes in working capital and an increase of $28.5 million in commodity derivative settlement payments offset by a decrease in operating revenues net of expenses of $76.9 million primarily as a result of a decrease in commodity prices.

Net cash used in investing activities. For the three months ended March 31, 2020, net cash used in investing activities decreased by $92.7 million compared to the three months ended March 31, 2019 primarily as a result of $45.0 million less spent on oil and gas property additions, $53.4 million less spent on gathering systems and facilities and $5.2 million less spent on other property and equipment offset by $5.1 million more spent on our investment in unconsolidated subsidiaries. Also, the proceeds from the sale of assets were $4.4 million less during the first quarter of 2020 than during the same period in 2019.

Net cash used in financing activities. For the three months ended March 31, 2020, net cash used in financing activities was $23.9 million less than for the three months ended March 31, 2019 primarily as a result of $28.5 million spent to repurchase 2026 Senior Notes and $32.2 million spent to repurchase of common stock during the first quarter of 2019 which were not spent during first quarter of 2020. Also, net borrowings on the credit facility during the first quarter of 2019 were $40.0 million compared to none during the first quarter of 2020.

Working Capital

Our working capital deficit was $144.6 million and $240.8 million at March 31, 2020 and December 31, 2019, respectively. Our cash balances totaled $32.0 million and $32.4 million at March 31, 2020 and December 31, 2019, respectively.

Due to the amounts that we incur related to our drilling and completion program and the timing of such expenditures, we may incur working capital deficits in the future. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, natural gas and NGL production will be the largest variables affecting our working capital. Due to the oil, natural gas and NGL price declines during the first and second quarter of 2020, we modified our drilling rig contracts to have minimal drilling activity for the remainder of the year. Please see *Note 13—Commitments and Contingencies* and *Note 4—Going Concern* in Part 1, Item 1. Financial Information of this Quarterly Report.

Debt Arrangements

For details of our debt arrangements including our credit facility, 2024 Senior Notes and 2026 Senior Notes, please see *Note 5—Long-Term Debt* in Part I, Item 1. Financial Information of this Quarterly Report. Additional debt disclosures specific to this *Management Discussion and Analysis* section are as follows.

If we experience certain kinds of changes of control, holders of our 2024 and 2026 Senior Notes may have the right to require us to repurchase their notes at 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of purchase.

Equity Arrangements

For details of our equity arrangements including our Series A Preferred Stock and Elevation Preferred Units, please see *Note 11—Equity* in Part I, Item 1. Financial Information of this Quarterly Report.

Critical Accounting Policies and Estimates

There were no material changes to our critical accounting policies and estimates from those disclosed in our Annual Report on Form 10-K for the year ended December 31, 2019 other than the deconsolidation of Elevation Midstream, LLC discussed in *Note 1—Business and Organization* in Part I, Item 1. Financial Information of this Quarterly Report.

Recent Accounting Pronouncements

Please see *Note 2—Basis of Presentation, Significant Accounting Policies and Recent Accounting Pronouncements* in Part 1, Item 1 of this Quarterly Report for a detailed list of recent accounting pronouncements.

Impact of Inflation/Deflation and Pricing

All of our transactions are denominated in U.S. dollars. Typically, as prices for oil and natural gas increase, associated costs rise. Conversely, as prices for oil and natural gas decrease, costs decline. Cost declines tend to lag and may not adjust downward in proportion to declining commodity prices. Historically, field-level prices received for our oil and natural gas production have been volatile. During the year ended December 31, 2019, commodity prices increased during the first, second and third quarter, and subsequently decreased in the fourth quarter. During the three months ended March 31, 2020, commodity prices decreased compared to the same period in 2019. Changes in commodity prices impact our revenues, estimates of reserves, assessments of any impairment of oil and natural gas properties, as well as values of properties being acquired or sold. Price changes have the potential to affect our ability to raise capital, borrow money, and retain personnel.

Off-Balance Sheet Arrangements

As of March 31, 2020, we did not have material off-balance sheet arrangements.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil, natural gas and NGL prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. LIBOR is used as a reference rate for certain of our financial instruments, such as our revolving credit facility. LIBOR is set to be phased out at the end of 2021. We are currently reviewing how the LIBOR phase-out will affect the Company, but we do not expect the impact to be material.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGL has been volatile and unpredictable for several years and this volatility is expected to continue in the future. The prices we receive for our oil, natural gas and NGL production depend on many factors outside of our control, such as the strength of the global economy and global supply and demand for the commodities we produce.

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we have periodically entered into commodity derivative contracts with respect to certain of our oil and natural gas production through various transactions that limit the downside of future prices received. We plan to continue our practice of entering into such transactions to reduce the impact of commodity price volatility on our cash flow from operations. Future transactions may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. These hedging activities are intended to support oil prices at targeted levels and to manage our exposure to oil price fluctuations.

For a summary of the Company's commodity derivative contracts as of March 31, 2020, please see *Note 6—Commodity Derivative Instruments* in Part 1, Item 1 of this Quarterly Report.

As of March 31, 2020, the fair market value of our oil derivative contracts was a net asset of $236.4 million. Based on our open oil derivative positions at March 31, 2020, a 10% increase in the NYMEX WTI price would decrease our net oil derivative asset by approximately $34.2 million, while a 10% decrease in the NYMEX WTI price would increase our net oil derivative asset by approximately $30.6 million. As of March 31, 2020, the fair market value of our natural gas derivative contracts was a net asset of $16.0 million. Based upon our open commodity derivative positions at March 31, 2020, a 10% increase in the NYMEX Henry Hub price would decrease our net natural gas derivative asset by approximately $3.8 million, while a 10% decrease in the NYMEX Henry Hub price would increase our net natural gas derivative asset by approximately $3.9 million. Please see "—How We Evaluate Our Operations—Derivative Arrangements."

Counterparty and Customer Credit Risk

Our cash and cash equivalents are exposed to concentrations of credit risk. We manage and control this risk by investing these funds with major financial institutions. We often have balances in excess of the federally insured limits.

We sell oil, natural gas and NGL to various types of customers, including pipelines and refineries. Credit is extended based on an evaluation of the customer's financial conditions and historical payment record. The future availability of a ready market for oil, natural gas and NGL depends on numerous factors outside of our control, none of

which can be predicted with certainty. For the three months ended March 31, 2020, we had certain major customers that exceeded 10% of total oil, natural gas and NGL revenues. We do not believe the loss of any single purchaser would materially impact our operating results because oil, natural gas and NGL are fungible products with well-established markets and numerous purchasers.

At March 31, 2020, we had commodity derivative contracts with nine counterparties. We do not require collateral or other security from counterparties to support derivative instruments; however, to minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. Additionally, we use master netting agreements to minimize credit risk exposure. The creditworthiness of our counterparties is subject to periodic review. For the three months ended March 31, 2020 and 2019, we did not incur any losses with respect to counterparty contracts. None of our existing derivative instrument contracts contain credit risk related contingent features.

Interest Rate Risk

At March 31, 2020, we had $470.0 million variable-rate debt outstanding. The impact on interest expense of a 1% increase or decrease in the average interest rate would be approximately $4.7 million per year. We may begin entering into interest rate swap arrangements on a portion of our outstanding debt to mitigate the risk of fluctuations in LIBOR if we have variable-rate debt outstanding in the future. Please see "—Liquidity and Capital Resources—Debt Arrangements."

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of our disclosure controls and procedures to ensure that the information required to be disclosed by us in the reports that we file or submit under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms and to ensure that such information is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure. Based upon that evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective as of March 31, 2020, due to the material weakness in internal control over financial reporting as described below.

Management's Material Weakness Remediation Plan

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Management determined that the Company did not design and maintain effective controls to determine the appropriate contract termination date and evaluate the potential accounting implications of changes in termination dates of contracts with customers. This material weakness resulted in a restatement of the Company's condensed consolidated financial statements as of and for the three and nine month periods ended September 30, 2019 and immaterial errors to the consolidated financial statements for the periods ended December 31, 2018, March 31, 2019 and June 30, 2019. The line items affected were oil sales, accounts payable and accrued liabilities, other non-current liabilities, inventory, prepaid expenses and other, and other non-current assets. Additionally, this material weakness could result in a misstatement of the aforementioned financial statement line items or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected.

The Company and its Board of Directors are committed to maintaining a strong internal control environment. Management has evaluated the material weakness described above and developed a remediation plan to address the material weakness. The remediation plan includes additional procedures around determining the contract termination date pursuant to the accounting treatment under ASC 606 - Revenue from Contracts with Customers. Management is committed to successfully implementing the remediation plan and plans to commence the evaluation of its updated design of internal controls for implementation expeditiously.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the three months ended March 31, 2020 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II—OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Information regarding our legal proceedings can found in *Note 13—Commitments and Contingencies — Litigation and Legal Items* in Part I, Item 1. Financial Information in this Quarterly Report.

ITEM 1A. RISK FACTORS

Factors that could materially adversely affect our business, financial condition, operating results or liquidity and the trading price of our common stock are described below and under Item 1A "Risk Factors", included in our Annual Report on Form 10-K filed with the SEC on March 12, 2020. The risks described below and in our annual report are not the only risks facing us. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition or future results. This information should be considered carefully, together with other information in this report and other reports and materials we file with the SEC.

We have no additional borrowing capacity under our revolving credit facility. Unless we are able to successfully restructure our existing indebtedness, obtain further waivers or forbearance from our existing lenders or otherwise raise significant capital, it is unlikely that we will be able to meet our obligations as they become due, and we may not be able to continue as a going concern.

Our working capital deficit was $144.6 million and $240.8 million at March 31, 2020 and December 31, 2019, respectively, and our cash balances totaled $32.0 million and $32.4 million at March 31, 2020 and December 31, 2019, respectively. For the year ended December 31, 2019, the Company incurred net losses of approximately $1.4 billion. Our continuation as a going concern is dependent upon attaining and maintaining profitable operations and, until that time, raising additional capital as needed, but there can be no assurance that we will be able to obtain sufficient financing. Our ability to generate positive cash flow from operations is dependent upon generating sufficient revenues. To date, our operations have been funded by the sale of oil, gas and NGL production based on prevailing market prices, which decreased significantly in March and April 2020. Our operations have also been funded through availability on our credit facility. As discussed in *Note 4—Going Concern* in Part I, Item I, Financial Information of this Quarterly Report, on April 27, 2020 the lenders under the revolving credit facility elected to reduce the borrowing base and elected commitments to $650.0 million from $950.0 million, and we borrowed all of the remaining available capacity under the revolving credit facility. As a result of the reduction of the borrowing base and elected commitments, it is probable that the Company will not meet the financial covenants under the revolving credit facility for the three months ended June 30, 2020 when assuming the Company’s current financial forecast.

If the Company does not obtain a waiver of its financial covenants for the three months ended June 30, 2020, the lenders under the revolving credit facility will be able to accelerate maturity of the debt. Any acceleration of the obligations under the revolving credit facility would result in a cross-default and potential acceleration of the maturity of the Company’s other outstanding long-term debt. These defaults create uncertainty associated with the Company’s ability to repay its outstanding long-term debt obligations as they become due and creates a substantial doubt over the Company’s ability to continue as a going concern.

The accompanying Consolidated Financial Statements have been prepared on a going concern basis which contemplates continuity of operations, realization of assets and liquidation of liabilities in the ordinary course of business. The accompanying condensed consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern. Our substantial indebtedness, liquidity issues and efforts to negotiate restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees;

- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

These events may have a material adverse effect on our business and operations.

The excess supply of oil and natural gas resulting from the reduced demand caused by the COVID-19 pandemic and the effects of actions by, or disputes among or between, oil and natural gas producing countries may result in transportation and storage constraints, reduced production and shut-in of our wells, any of which would adversely affect our business, financial condition and results of operations.

The recent worldwide outbreak of COVID-19, the uncertainty regarding the impact of COVID-19 and various governmental actions taken to mitigate the impact of COVID-19, have resulted in an unprecedented decline in demand for oil and natural gas. At the same time, the decision by Saudi Arabia in March 2020 to drastically reduce export prices and increase oil production followed by curtailment agreements among OPEC and other countries such as Russia further increased uncertainty and volatility around global oil supply-demand dynamics. To the extent that the outbreak of COVID-19 continues to negatively impact demand and OPEC members and other oil exporting nations fail to implement production cuts or other actions that are sufficient to support and stabilize commodity prices, we expect there to be excess supply of oil and natural gas for a sustained period. This excess supply could, in turn, result in transportation and storage capacity constraints in the United States, including in the DJ Basin. If, in the future, our transportation or storage arrangements become constrained, we may incur significant operational costs if there is an increase in price for services or we may be required to shut-in or curtail production or flare our natural gas. If we were required to shut-in wells, we might also be obligated to pay certain demand charges for gathering and processing services and firm transportation charges for pipeline capacity we have reserved. Further, any prolonged shut-in of our wells may result in decreased well productivity once we are able to resume operations, and any cessation of drilling and development of our acreage could result in the expiration, in whole or in part, of our leases. All of these impacts resulting from the confluence of the COVID-19 pandemic and the price war between Saudi Arabia and Russia may adversely affect our business, financial condition and results of operations.

Due to the commodity price environment, we have postponed or eliminated a portion of our developmental drilling. A sustained period of weakness in oil, natural gas and NGLs prices, and the resultant effects of such prices on our drilling economics and ability to raise capital, will require us to reevaluate and further postpone or eliminate additional drilling. Such actions would likely result in the reduction of our PUDs and related PV-10 and a reduction in our ability to service our debt obligations. If we are required to further curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, if oil, natural gas and/or NGLs prices experience a sustained period of weakness, our future business, financial condition, results of operations, liquidity, and ability to finance planned capital expenditures may be materially and adversely affected.

The inability to renegotiate our transportation and marketing contracts may adversely affect our business and financial condition.

We enter into firm transportation, gas processing, gathering and compression service, water handling and treatment, or other agreements that require minimum volume delivery commitments in the normal course of our business. During the spring of 2020, in light of market conditions, we began renegotiating our transportation, gathering and marketing contracts to reduce, restructure or eliminate our minimum volume commitments to our transportation, gas processing and gathering and compression service providers. Any inability to renegotiate transportation and marketing contracts to reflect current market conditions increases our marketing and transportation costs, inclusive of costs related to unutilized transportation and/or processing capacity for previously planned volumes. Such increased costs decrease realized revenue at any notional commodity value, negatively impacting financial results, competitiveness, and our overall financial condition. If we are unable to modify our minimum volume commitments, we may not have sufficient production to fulfill them which would have an adverse effect on our business and financial condition.

Failure to maintain the continued listing standards of NASDAQ could result in delisting of our common stock, which could negatively impact the market price and liquidity of our common stock and our ability to access the capital markets.

Our shares are listed on the NASDAQ Global Market ("NASDAQ") and the continued listing of our shares on NASDAQ is subject to our ability to comply with NASDAQ's continued listing requirements, including, among other things, a minimum closing bid price requirement of $1.00 per shares. On March 30, 2020, we received a letter from the Listing Qualifications Department of NASDAQ notifying us that our shares closed below the $1.00 per unit minimum bid price required by NASDAQ Listing Rule 5450(a)(1) for 30 consecutive business days and that we have a period of 180 calendar days in which to regain compliance.

We are considering options to regain compliance. If we are unable to regain compliance, however, any delisting from NASDAQ could result in even further reductions in our price per share, substantially limit the liquidity of our common stock, and materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NASDAQ could also have other negative results, including the potential loss of institutional investor interest and fewer business development opportunities.

There is no assurance that we will continue to maintain compliance with NASDAQ continued listing standards. Our business has been and may continue to be affected by worldwide macroeconomic factors, which include uncertainties in the credit and capital markets as well as with respect to commodity prices. External factors that affect our share price, such as liquidity requirements of our investors, as well as our performance, could impact our market capitalization, revenue and operating results, which, in turn, affect our ability to comply with the NASDAQ's listing standards. The NASDAQ has the ability to suspend trading in our shares or remove our shares from listing on the NASDAQ if in the opinion of the exchange: (a) the financial condition and/or operating results of the Company appear to be unsatisfactory; (b) it appears that the extent of public distribution or the aggregate market value of our units has become so reduced as to make further dealings on the exchange inadvisable; (c) we have sold or otherwise disposed of our principal operating assets, or have ceased to be an operating company; (d) we have failed to comply with our listing agreements with the exchange; or (e) any other event shall occur or any condition shall exist which makes further dealings on the exchange unwarranted.

There is substantial risk that it may be necessary for us to seek protection under Chapter 11 of the United States Bankruptcy Code, which may have a material adverse impact on our business, financial condition, results of operations, and cash flows, would have a material adverse impact on the trading price of our securities, and could place our shareholders at significant risk of losing all of their investment in our shares.

We have engaged financial and legal advisors to assist us in, among other things, analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives to restructure our indebtedness in private transactions. Due to our current financial constraints, there is a substantial risk that it may be necessary for us to seek protection under Chapter 11.

Seeking bankruptcy court protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. As long as a Chapter 11 proceeding continues, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing on our business operations. Bankruptcy court protection also may make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, during the period of time we are involved in a bankruptcy proceeding, our customers and suppliers might lose confidence in our ability to reorganize our business successfully and may seek to establish alternative commercial relationships.

Additionally, all of our indebtedness is senior to the existing common stock and preferred stock in our capital structure. As a result, we believe that seeking bankruptcy court protection under a Chapter 11 proceeding could cause the shares of our existing common stock to be canceled, result in a limited recovery, if any, for shareholders of our common stock, and would place shareholders of our common stock at significant risk of losing all of their investment in our shares.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

ITEM 5. OTHER INFORMATION

We are providing the following disclosure in lieu of filing a Current Report on Form 8-K relating to "Item 5.02 Departure of Directors or Certain Officers; Election of Directors; Appointment of Certain Officers; Compensatory Arrangements" of Form 8-K.

On May 8, 2020, the Company entered into an Indemnification Agreement (the "Indemnification Agreement") with Marianella Foschi. The Indemnification Agreement requires the Company to indemnify Ms. Foschi to the fullest extent permitted under Delaware law against liability that may arise by reason of her service to the Company, and to advance certain expenses incurred as a result of any proceeding against her as to which she could be indemnified.

The foregoing description of the Indemnification Agreement is not complete and is qualified in its entirety by reference to the full text of the Indemnification Agreement, which is attached as Exhibit 10.10 to this Current Report on Form 10-Q and incorporated into this Item 5 by reference.

ITEM 6. EXHIBITS

(a) Exhibits:

The exhibits listed on the accompanying Exhibit Index are filed, furnished or incorporated by reference as part of this report, and such Exhibit Index is incorporated herein by reference.

INDEX TO EXHIBITS

Exhibit Number	Description
3.1	Certificate of Incorporation of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
3.2	Certificate of Designations of Series A Preferred Stock of Extraction Oil & Gas, Inc., filed with the Secretary of State of the State of Delaware on October 17, 2016 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 21, 2016).
3.3	Bylaws of Extraction Oil & Gas, Inc., dated October 11, 2016 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on October 14, 2016).
†10.1	Restricted Stock Unit Award Agreement (Thomas B. Tyree) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.2	Employment Agreement dated as of March 4, 2020, between the Company and Thomas B. Tyree (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.3	Indemnification Agreement (Thomas B. Tyree) (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.4	Amended and Restated Employment Agreement effective as of March 4, 2020, between the Company and Matt Owens (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.5	Extraction Oil & Gas, Inc. Executive Severance Plan (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.6	Form of Participation Agreement (Executive Severance Plan) (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 5, 2020).
†10.7	Employment Transition Agreement, dated March 18, 2020, between Extraction Oil & Gas, Inc., XOG Services, LLC. and Mark A. Erickson (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 20, 2020).
†10.8	Form of Restricted Stock Unit Award Agreement (Performance-Vesting, Share-Settled) (for Officers) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-37907) filed with the Commission on March 20, 2020).
†10.9	Form of Restricted Cash Award Agreement (Employees) (incorporated by reference to Exhibit 10.3 to the Company's 8-K (File No. 001-37907) filed with the Commission on March 20, 2020).
*†10.10	Indemnification Agreement (Marianella Foschi)
*31.1	Certification of Chief Executive Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
*31.2	Certification of Chief Financial Officer required by Rules 13a-14 and 15d-14 under the Securities Exchange Act of 1934.
**32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
**32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
*101	Interactive Data Files

†	Management contract or compensatory plan or agreement.
*	Filed herewith.
**	Furnished herewith.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: May 11, 2020.

Extraction Oil & Gas, Inc.

By: /S/ MATTHEW R. OWENS
Matthew R. Owens
President and Chief Executive Officer
(principal executive officer)

By: /S/ TOM L. BROCK
Tom L. Brock
Vice President and Chief Accounting Officer
(principal financial officer)

EXHIBIT L

EXPERT REPORT OF
DAVID J. HAAG

I. INTRODUCTION AND SUMMARY

1. My name is David J. Haag and my business address is 1155 15th Street, N.W., Suite 1004, Washington, D.C. 20005. I am President and Chief Executive Officer of Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"), a nationally recognized energy consulting firm based in Washington, D.C. BWMQ offers technical, economic, and policy assistance to the various segments of the oil pipeline industry, natural gas pipeline industry, and electric utility industry on business and regulatory matters.

2. I have been retained by the law firm of Morris, Nichols, Arsht & Tunnell LLP, counsel in this proceeding to Platte River Midstream, LLC ("PRM"), DJ South Gathering, LLC ("DJS"), and Platte River Holdings, LLC, to provide my expert opinion regarding the impacts to the public interest if Extraction Oil & Gas, Inc. ("XOG" or "Shipper"), who is the debtor in this proceeding, was to reject its currently effective pipeline transportation service agreements with PRM and DJS (collectively the "TSAs").[1]

3. In general terms, an assessment of the "public interest" seeks to measure the overall impacts to the welfare of the public resulting from a specific action or proposed action, focusing particularly on the impacts to public safety, health, and welfare concerns.

4. My analysis begins with a detailed review of the TSAs to understand and establish a baseline starting point from which to measure the impacts to the public interest resulting from a number of likely potential actions should the TSAs in fact be rejected by XOG.

[1] For clarity, I also refer to the subject transportation service agreements individually where necessary as the "PRM TSA" and "DJS TSA" respectively.

5. My review of the impacts of the proposed rejections focuses on the impacts to public safety, health, and welfare concerns under the likely crude oil delivery alternatives that would be available to XOG in lieu of utilizing PRM and DJS. I also examine the likely impacts that the proposed rejections would have on the availability of supply to other pipelines and therefore ultimately to consumers.

4. The results of my review indicate that the proposed rejections of the PRM TSA and the DJS TSA are likely to cause harm to the health, safety, and welfare of the public, particularly in the jurisdictions where XOG operates. In addition, the evidence shows that the proposed rejections will cause a disruption in the supply of crude oil available to some pipelines, as well as a potential reduction in the amount of crude oil delivered to the major crude oil hub located at Cushing, Oklahoma.

5. In the formation of my opinions, I have reviewed and relied upon the following documents and internet websites:

- XOG Motion for Rejection of Contracts dated August 11, 2020
- Overview Map of ARB Platte River Holdings
- http://www.arbmidstream.com/Operation/platte-river-gathering-system
- http://www.grandmesapipeline.com/
- Grand Mesa Pipeline Tariff
- PRM First Amended and Restated Transportation Services Agreement
- PRM PDO
- FERC Order on PRM PDO
- PRM Tariff
- http://www.arbmidstream.com/Operation/dj-south-gathering-system
- DJS Open Season dated December 2018
- 2020-09-12 XOG Supplemental Responses to Platte River Interrogatories
- [redacted]
- Axis Exploration LLC_ FINAL Oil and Gas Agreement - City of Aurora
- Extraction CDP July 27, 2018 – Broomfield
- Extraction Form 10-K – 2019
- DJ South 2019 FERC Form 6
- DJ South FERC Form 6Q – June 2020
- Platte River 2019 FERC Form 6

- DJ South FERC Form 6Q – June 2020
- White Cliffs Pipeline Tariff
- Saddlehorn Pipeline Tariff
- Tallgrass Pony Express Pipeline Tariff
- [redacted]
- XOG Motion for Rejection of Contracts dated June 15, 2020
- Opinion Authorizing Rejection of Rockies Express by Ultra dated August 21, 2020
- ARB Fact Sheet
- [redacted]
- Verified Complaint of Extraction Oil & Gas, Inc. dated September 14, 2020

I have also reviewed the production of the Debtors dated September 12 and 13, 2020[2] and spoken to representatives of PRM and DJS.

Finally, several other internet websites which I have reviewed in the preparation of this report are also footnoted within this report.

II. EDUCATIONAL AND PROFESSIONAL BACKGROUND

6. My personal curriculum vitae, which is attached hereto, details my career and work experience in the oil and natural gas pipeline industry, as summarized below.

7. I graduated from the University of Calgary, Canada with a B.A. Degree (with Honors), majoring in Economics and minoring in Management. I am currently completing my Master's Degree in Economics with a Concentration in Public Utility Policy and Regulation at New Mexico State University. In addition, since 2013, I have instructed a Seminar for the Center for Public Utilities at New Mexico State University on the proper determination of an interstate natural gas pipeline's regulated cost of service.

8. Over the course of my career, I have participated in numerous rate case and certificate proceedings at the Federal Energy Regulatory Commission ("Commission" or "FERC") on behalf of multiple interstate FERC regulated pipelines. I have filed expert testimony

[2] My understanding is that documents continue to be produced by XOG and, therefore, I reserve the right to amend my report based on new documents received.

and/or submitted affidavits on numerous topics, including rate design, pipeline proxy groups, business risk assessment, capital structure, cost classification, cost allocation, billing determinants, discount adjustments, market power, and other rate and tariff related issues.

9. I became the Chief Executive Officer of BWMQ in September 2019. Prior to this position, I was employed at a number of pipeline companies in roles of increasing responsibility. Most recently, I served as Vice President, Regulatory and Chief Compliance Officer for Tallgrass Energy, LP ("Tallgrass"), where I was primarily responsible for identifying, overseeing, and implementing regulatory strategies across each pipeline entity, including crude oil pipelines, natural gas transmission pipelines, and storage facilities; overseeing the management of all Tallgrass rate and cost of service related filings, including Natural Gas Act Section 4 rate case and tariff filings, as well as the development of complex financial modeling for strategic analysis.

10. Prior to joining Tallgrass, I served as the Director of Rates for Boardwalk Pipeline Partners, L.P. ("Boardwalk"), where I was accountable for the various rate and cost of service matters across all regulated Boardwalk entities, including the provision of testimony and preparation of financial models and strategic analysis.

11. I was previously employed as Manager, Rates and Regulatory Affairs for Portland Natural Gas Transmission System ("PNGTS"), where I prepared, filed, and managed all PNGTS regulatory filings; major PNGTS filings included multiple rate case filings, Commission certificate applications, NAESB compliance filings, federal district court matters, as well as the bankruptcy of a major shipper. At PNGTS, I filed testimony with the Commission

on various rate and regulatory matters involving cost of service issues, rate levelization, and pipeline transportation values.

12. Early in my career, I worked in Sales and Marketing for TransCanada Pipelines Ltd. (now TC Energy Corporation) in Calgary, Canada, and as such I am also familiar with Canadian pipeline operations and regulations.

III. BACKGROUND AND BASELINE ANALYSIS

13. On August 11, 2020, XOG filed a Motion to reject both the PRM TSA and DJS TSA in this proceeding (the "Motion"). In the Motion, XOG stated that it had determined, in the exercise of its business judgment, that the costs incurred under the TSAs constituted an unnecessary drain on XOG's resources and / or that more cost-efficient alternatives existed. Consequently, XOG proposed that both these contracts be rejected effective August 11, 2020. (See Paragraph 8 of the Motion).

14. XOG's Motion further stated that it believed that rejection of the PRM TSA and the DJS TSA was in the best interests of the Debtors, their estates, and all parties in interest. (See Paragraph 8 of the Motion) In addition, XOG stated that they had determined that both the PRM TSA and DJS TSA were neither compatible with their ongoing business needs nor a source of potential value for their future operations, creditors, or other parties in interest. (See Paragraph 10 of the Motion). I examine these claims in detail below, following a review of the PRM and DJS systems and the TSAs.

15. The PRM TSA provides for pipeline transportation service on Platte River Midstream, LLC. PRM operates a crude oil gathering pipeline system located in the Denver-Julesburg Basin in Weld County, Colorado. PRM is regulated by the Federal Energy Regulatory Commission ("FERC") pursuant to the Interstate Commerce Act ("ICA"), *49 U.S.C. App.*

§ 1 et seq. The system is capable of moving up to 157,000 barrels per day and currently includes over 95 miles of crude oil gathering lines as well as truck unloading at the Lucerne Hub (located near Lucerne, Colorado). At Lucerne, PRM delivers to the Grand Mesa Pipeline, LLC ("Grand Mesa"), an unaffiliated FERC jurisdictional pipeline which delivers barrels in interstate commerce to Cushing, Oklahoma.

16. Grand Mesa extends approximately 550 miles southeast from Lucerne, Colorado to the Cushing Hub in Cushing, Oklahoma. The pipeline is capable of transporting up to 150,000 barrels per day for delivery to Cushing. The Cushing Hub is one of the world's largest oil-storage hubs, with approximately 73 million barrels of working capacity, representing approximately 13 percent of total U.S. oil storage.[3] Numerous oil pipeline systems converge at Cushing, Oklahoma. The Cushing Hub is a major trading hub for crude oil and a price settlement point for West Texas Intermediate production on the New York Mercantile Exchange.

17. In December 2015, prior to being constructed, the PRM system conducted an "open season"[4] wherein interested shippers were provided the opportunity to execute a transportation services agreement and become a Committed Shipper on the system. As specified in the open season, Committed Shippers were required, for an initial period of five (5) years to either (a) dedicate for transportation on the PRM pipeline all (or a portion, as the case may be) of the crude oil that is produced from certain, specified acreage ("Acreage Dedication") and to pay PRM for any Acreage Dedication volumes not shipped

[3] See: https://oilprice.com/Energy/Energy-General/The-US-Still-Dominates-World-Oil-Prices.html
[4] An "open season" is utilized by pipelines to obtain binding commitments from shippers for pipeline transportation. An open season outlines the terms and conditions under which the service is being offered by the pipeline to interested shippers.

or (b) commit to ship a specified volume of crude oil ("Committed Volume") on the pipeline and pay PRM for any such Committed Volumes not shipped.

The proposed pipeline service was also conditioned on PRM receiving the various regulatory approvals it required, including approval of the terms and conditions of service offered during the open season process and reflected in the TSA which was part of the open season.

18. The TSA, [redacted]

19. On April 28, 2016, the FERC issued an Order in Docket No. OR16-11, finding that the provisions of the TSA (which included the Acreage Dedication) as explained in the Petition appeared consistent with Commission precedent under the Interstate Commerce Act.

20. In April 2017, PRM and XOG entered into the currently effective PRM TSA that continues through October 31, 2026. The agreement sets forth the various terms and conditions governing the transportation of XOG's crude petroleum on the PRM system and reflects that XOG is an Acreage Dedication shipper. The transportation service, including the underlying rates charged, is provided pursuant to the PRM TSA and the PRM Tariff, which is on file with, and approved by the FERC.

21. As an Acreage Dedication shipper, under Section 2.1 of the PRM TSA, XOG [redacted] (defined in the TSA and reproduced below) to PRM.

The PRM TSA defines Interests as follows:

[redacted]

The PRM TSA further defines "Dedication Area" as:

[redacted]

In addition, Section 13.9 of the PRM TSA expressly provides that the agreement,

[redacted].

22. Section 11 of the PRM TSA deals with events of default under the agreement. Section 11.3(b) provides that, if XOG is the defaulting party, PRM may [redacted] Therefore, if the PRM TSA were to be rejected, and thus breached, by XOG, PRM would not be obligated to accept XOG's production for transportation as an uncommitted or "walk-up" shipper.

23. The executed PRM TSA was relied upon by PRM to provide the levels of financial and throughput commitment needed to construct the PRM system. The acreage dedication

further required PRM to directly connect the pipeline system to Extraction's well pads within the defined Dedication Area.

24. The DJS TSA provides for pipeline transportation service on DJ South Gathering, LLC. DJS operates a crude oil gathering pipeline system which is also regulated by the FERC pursuant to the ICA. The DJS system consists of three distinct pipeline segments; an approximately 29 mile pipeline from the Badger receipt point in Weld County, Colorado to Platteville (the "Badger Pipeline") with a design capacity of 56,000 barrels per day, an approximately 41 mile pipeline from the Bennett/Matador receipt point in Adams County, Colorado to Platteville (the "Matador Pipeline") with a design capacity of 150,000 barrels per day, and a 23 mile pipeline from Platteville to Lucerne (the "Freedom Pipeline") with a design capacity of 50,000 barrels per day.

25. At Lucerne, DJS delivers to Grand Mesa. At Platteville, DJS shippers can access three unaffiliated FERC jurisdictional pipelines for further deliveries in interstate commerce to Cushing, Oklahoma. These three pipelines are: (1) Saddlehorn Pipeline Company, LLC ("Saddlehorn"), (2) White Cliffs Pipeline, LLC ("White Cliffs"), and (3) Tallgrass Pony Express Pipeline, LLC ("Pony Express").

26. The Saddlehorn pipeline is currently capable of transporting 190,000 barrels per day of crude oil from Platteville to Cushing. White Cliffs is capable of delivering 215,000 barrels per day to Cushing. Finally, Pony Express is currently capable of transporting approximately 90,000 barrels per day from Colorado to Cushing.

27. In May 2018, DJS and XOG entered into the DJS TSA. The DJS TSA sets forth the various terms and conditions for the transportation of XOG's crude petroleum through the DJS system, reflecting that XOG is an acreage dedication shipper with a minimum volume

commitment as reflected in the agreement, consistent with what was presented in the December 2018 DJS open season. The transportation service, including the underlying rates charged, are also provided pursuant to the DJS Tariff on file with, and approved by the FERC.

28. In December 2018, prior to being constructed, the DJS system conducted a binding open season wherein all interested shippers were provided the opportunity to execute a transportation services agreement and become a Committed Shipper on the to-be constructed pipeline system. As specified in the open season, interested shippers were provided with the opportunity to make long-term acreage dedications either with or without minimum volume commitments for transportation service on the system in exchange for access to priority capacity for up to 90 percent of the pipeline's capacity. All Committed Shippers were required to make an acreage dedication; however, the specific terms and conditions of service that a Committed Shipper received was dependent on whether or not the Committed Shipper also elected to make a minimum volume commitment. As part of the open season, DJS provided two separate pro forma transportation service agreements, one with and one without minimum volume commitments.

29. As an acreage dedication shipper with a minimum volume commitment, under Section 2.1 of the DJS TSA, [redacted] (as explicitly defined in the DJS TSA) to DJS.

The DJS TSA defines Interests as follows:

[redacted]

[redacted]

The DJS TSA further defines the "Dedication Area" as:

[redacted]

30. The dedications and commitments are characterized as covenants running with the land in section 2.5 of the DJS TSA. Section 2.5 further provides that XOG [redacted].

31. Article XII of the DJS TSA deals with events of default under the agreement. Section 12.3(b) further provides that, if XOG is the defaulting party, DJS may [redacted]. Therefore, if the DJS TSA were to be rejected by XOG, as with

the PRM TSA, they would not be entitled to become an uncommitted or "walk-up" shipper and continue to use DJS prior to curing the event of default.

32. As reported on the XOG website, XOG's operations focus "entirely on the Wattenberg Field of the Denver-Julesburg Basin" https://extractionog.com The bulk of the Wattenberg Field lies in Weld County, but it also extends into Adams, Boulder, Broomfield, Denver, and Larimer Counties. https://www.shaleexperts.com/plays/niobrara-shale/Overview Accordingly, under the acreage dedications contained in the PRM TSA and the DJS TSA, a large portion of XOG's production is dedicated and committed to utilizing either the PRM or DJS pipeline systems as applicable.

33. Notwithstanding these acreage dedication provisions contained in the PRM TSA and the DJS TSA, the Motion to reject filed by XOG claims that these agreements are neither compatible with their ongoing business needs nor a source of potential value for their future operations, creditors, or other parties in interest.

34. My analysis does not seek to opine on the merits of the acreage dedications. Rather, my analysis is focused on the statement made by XOG that these agreements are neither compatible or valuable to their future operations, and that more cost-efficient alternatives are available; therefore, it appears certain that XOG intends to pursue alternative transportation arrangements for its crude oil production. My conclusions relate to the impact of the potential alternative arrangements as further discussed in Section IV of my report.

IV. IMPACTS OF THE PROPOSED REJECTION ON THE PUBLIC INTEREST

35. As previously stated, the main of objective of my analysis is to identify and assess the impacts to the public interest resulting from the proposed rejection by XOG of the TSAs.

36. To undertake this assessment, I have examined the two alternatives to the continued use of the TSAs that XOG has identified in discovery, namely the use of two alternate pipeline systems as well as the use of trucks to transport their production. I also analyze two other potential alternatives. I then compare the impacts of each of these alternatives on the public safety, health, and welfare with the pre-rejection status quo in order to determine if the public interest is enhanced or harmed by the alternative.

37. In addition, the next section of my report evaluates whether the proposed rejections will cause disruptions in the supply of crude oil available to other pipelines and / or to consumers.

Potential Alternative Analysis – Shut-In of Production

38. The identification and examination of potential alternatives available to XOG (in lieu of continuing with the two TSAs in question) is necessary in order to assess the impacts to the public interest of each potential course of action compared to the pre-rejection status quo to determine if the public interest is served or disserved.

39. As discussed previously, both of the TSAs [redacted] Further, both of the TSAs also state that this dedication and commitment language applies to all of XOG's successors and assigns.

40. This shut-in of production alternative examines the public interest impacts if XOG's production were cut-off from all markets, that is that the production were shut-in consistent

with the acreage dedication language (i.e. no other alternative transportation methods were found to be permissible) and the public interest impacts of this course of action. This alternative also reflects that XOG cannot elect to ship on PRM or DJS as an uncommitted or "walk-up" shipper after defaulting (as a consequence of rejection of) the TSAs.

41. To examine the impacts of this alternative, I have reviewed XOG's June 2020 actual gross production data, as reported by Enverus, sorted by Lease location (i.e. township and range) in order to identify the levels of XOG production that are currently utilizing the PRM and DJS systems, and utilize this as a proxy for the amount of production that would be shut-in.

42. [redacted] See Appendix A attached hereto.

43. [redacted] See Appendix B attached hereto.

44. [redacted]

45. There are a number of public interest implications that would arise from a shut-in of the XOG production. First and foremost, shutting in the production would have an immediate financial impact not on just XOG and its partners and affiliates, but to numerous other stakeholders as well.

46. The E.I.A. reports that the Crude Oil First Purchase Price (in Dollars per Barrel) for Colorado in June 2020 was $30.77 per barrel. See https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=pet&s=f004008__3&f=m Therefore, shutting

[redacted]

47. The loss of these revenues adversely impacts numerous stakeholders. From these revenues royalty payments are made, corporate and personal income taxes are paid to multiple governments, property and school taxes are paid, employees and contractors wages are paid, charitable contributions are made, amongst numerous other benefits.

48. The production also helps to meet local and national demand for energy and petroleum related end-use products - crude oil is used to make the petroleum products used to fuel airplanes, cars, and trucks; to heat homes; and to make a wide array of products ranging from medicines to plastics.

49. Arguments can be made that shutting-in crude oil production and instead encouraging and developing broader reliance on "greener" sources of energy are a benefit the public interest, particularly in the long-run. However, given that the XOG production has already been discovered, drilled, and connected, it is most reasonable to conclude that the *current* public interest is better served by continued production from these existing wells. When compared to the pre-rejection status quo, continued production does not further adversely impact the health, safety, and welfare of the public and is more beneficial than the shut-in of this production.

50. While it is possible that the XOG production could be shut-in upon rejection, a reorganized XOG will obviously seek to avoid a production shut-in post rejection to remain a going concern. Thus, for the continued assessment of likely potential alternatives, I will assume that the XOG production is not ultimately shut-in.

Continued Production – Potential Alternatives

51. Crude oil producers, including XOG, are faced with the daily need to move their product from the oil well to a market, be it a refinery or to a storage tank for future refining. Once the crude oil reaches a refinery, it is then processed into various end-use products for ultimate sale to end users and consumers. All crude oil needs to be transported in one way or another to ultimately become an end use product needed by the market.

52. Accordingly, after a producer successfully extracts crude oil from the ground, they must consider the infrastructure, geography and cost implications to determine the best mode of transportation. Economics dictates that the best option will be the one that minimizes costs while still moving the product safely and reliably.

53. There are currently four primary modes by which crude oil is transported to refineries in the United States. These four modes are: (1) pipeline, (2) marine vessel, (3) rail, and (4) trucks. The U.S. Energy and Information Administration tracks the utilization of these transport modes and reports that in 2019, pipelines delivered approximately 84.4% of all the domestic crude oil production received by U.S. refineries. Marine vessels delivered approximately 10.4% of domestic crude production, while trucks delivered approximately 2.8%, with rail cars delivering the remaining 2.4% of domestic production. See https://www.eia.gov/dnav/pet/pet_pnp_caprec_dcu_nus_a.htm

54. Given that it is a land-locked state, it is not possible for producers in Colorado to utilize marine vessels to transport crude oil. Of the remaining three transportation modes available to Colorado producers, pipelines are normally the most economic as well as the safest means of transportation, reflecting why pipelines transport the overwhelming majority of crude oil to U.S. refineries. A general rule of thumb used in the industry to value long haul transportation options is that it costs $20 per barrel to move crude oil by

truck, $10 by rail and $5 by pipeline, although these cost vary by geography. (For example see: https://fas.org/sgp/crs/misc/R43390.pdf and https://www.mysanantonio.com/news/local/article/Crude-oil-will-continue-rolling-by-train-4689871.php) The availability of pipeline capacity has a determinative effect on the price and availability of crude oil to the market.

55. While this general "rule of thumb" provides a high-level, relative magnitude of transportation prices, I have investigated the current market prices faced by producers in northeast Colorado for both pipeline and truck transportation options, as discussed further below.

Potential Transportation Alternatives – New Pipeline Construction

56. A potential alternative available to XOG in lieu of utilizing the PRM or DJS systems is that XOG could construct, or cause to be constructed, new pipeline connections to gather their production for delivery to either Lucerne or Platteville in lieu of using their existing TSAs. XOG has stated in its response to Interrogatory 16, dated September 12, 2020, that:

> *For those well sites where the use of pipelines for oil is required, and where other pipeline gathering systems are available, Debtors believe that they would have alternative oil gatherers that would be able to gather the oil from such pads.*

These "alternative gatherers" which XOG has identified are the [redacted] and / or the [redacted], would, in many instances, need to construct new (and duplicative) pipelines to connect the XOG pads, which are already connected to PRM or DJS.

57. The [redacted] consists of approximately [redacted] The [redacted]

connects with each of the four large interstate crude oil pipelines that traverse the Denver Julesburg Basin.

See [redacted]

58. The [redacted] consists of approximately [redacted] Colorado, in addition to some local markets. See [redacted]

59. XOG's preference for the continued use of pipelines is reflective of the provisions contained in XOG's operator agreements which are currently in place with various local jurisdictions, which require much of the production to be shipped from the well via a pipeline only. For example, XOG's Comprehensive Drilling Plan with the City and County of Broomfield requires that XOG transport their crude oil by pipeline to delivery points outside of the city limits of Broomfield. XOG's Operator Agreements with the City of Aurora and the City of Commerce City have similar provisions that also require them in many instances to use pipelines to transport their crude oil.

60. Local governments negotiate these agreements on behalf of their citizens and are tasked with representing the underlying public interest concerns of the citizens of these jurisdictions. A reflection of this representation in action is the requirement for XOG to utilize pipelines, which serves to reduce truck traffic, noise, and vehicle emissions, reducing the potential for harm to the public.

61. Any assumption that these carefully negotiated and agreed-upon contractual requirements (which were negotiated with the public interest in mind) can be easily amended should not

be made in a cavalier manner, as there would be further implications to the public interest that would require assessment, including such matters as potential impacts on property valuations as an example, as well as the health and safety of residents. Indeed, under a recently enacted law in Colorado, SB 19-181, local governments have new authority to regulate oil and gas development. Under this law, cities have the ability to enact municipal ordinances that can restrict of limit oil and gas production and development. Indeed, new restrictions appear to have already been implemented with respect to Extraction's drilling activities, leading to lawsuits filed by Extraction against the City of Broomfield.[5]

62. In addition, new pipeline construction, should it be required, is a large and capital-intensive undertaking. Any new pipelines or segments that would need to be constructed to connect to the XOG production would first need to be permitted and approved by each local jurisdiction that the new lines would traverse. While each jurisdiction in Colorado has its own processes and set of requirements that must be satisfied to obtain a permit, each jurisdiction generally requires a detailed application package that includes the proposed routing, right-of-way and easement information, stormwater plans, and other project-specific details be submitted for consideration and review prior to approval.[6]

63. The permitting of new pipelines in Colorado can be a time-consuming process. Depending upon the complexity of the project, permitting can often take from three to eighteen or

[5] See Extraction Oil and Gas, Inc. vs. the City and Country of Broomfield, U.S. District Court for the District of Colorado, Civil Action No. 20-2779.

[6] An example highlighting the difficulties of obtaining new permits is the lawsuit filed by XOG against the City of Broomfield September 14, 2020, referenced in footnote 5 above. In this suit, XOG seeks a declaration that the City of Broomfield's regulations violate XOG's contractual and constitutional rights. In this action, XOG emphasizes the importance of the use of its pipelines to minimizing the adverse impacts of its oil production on city residents.

more months. In addition to permitting requirements, the project(s) would also need time to negotiate for land and rights-of-way, materials procurement, and construction activities.

64. Some jurisdictions in Colorado, including Adams County (where DJS has facilities) and the town of Kersey (where PRM) has facilities, also require the entity to first obtain a Conditional Use Permit ("CUP"). A typical CUP application can be hundreds or more pages and must satisfactorily address numerous public interest issues such as the need for the project, anticipated impacts on existing infrastructure, public safety impacts, descriptions of alternatives, benefits to the local economy, financial burdens to residents, as well as an environmental impacts analysis. Obtaining a CUP can take several months to well over a year, depending on the complexity of the project and the amount of input received from the public.

65. Similar to a CUP, Weld County (where much of the PRM and DJS systems are located) requires pipelines to obtain a land use permit for facilities in residential, commercial, estate, and Planned Unit Development zone districts, as well as in the city of Greeley. Weld County also requires a Location Assessment for Pipelines ("LAP") for the construction of any pipeline 12 inches or greater in diameter. Obtaining an LAP in Weld County can take several months. The permitting and related procurement and construction activities required for new gathering pipeline construction require the input from, and draw on the resources of, numerous stakeholders including local governments, private landowners and other private citizens who participate in these important processes.

66. Much of XOG's production is near populated areas, which presents additional challenges in acquiring the necessary permits. On page 35 of XOG's 2019 Form 10-K, XOG warns investors of this fact, stating:

> *Much of our operations are within the city limits of various municipalities in northeastern Colorado. In such urban and other populated areas, we may incur additional expenses, including expenses relating to mitigation of noise, odor and light that may be emitted in our operations, expenses related to the appearance of our facilities and limitations regarding when and how we can operate. The process of obtaining permits for drilling or for gathering lines to move our production to market in such areas may be more time consuming and costly than in more rural areas.*

67. In light of the fact that XOG's production is already connected to functional oil gathering pipeline systems, any strategy to pursue the constructing of alternative pipeline connections will be severely challenged to be found to be beneficial to the public interest as compared to maintaining the pre-rejection status-quo. In addition to the long lead times to obtain required permits, the additional costs (both financial and human capital costs) which would be borne by the public related to processing the applications, impacts of construction and reclamation, are not off-set by any new public benefits when an existing pipeline is being duplicated. Furthermore, XOG would also need to utilize other alternatives to continue producing their crude oil while the new pipelines and connections were being constructed, potentially creating other public interest concerns. All of the risks to the public health, safety, and welfare that arise from the construction of duplicative pipelines and pipeline connections are wholly avoidable. This fact alone may put the receipt of many of these permits in jeopardy.

68. Although the direct costs of any new pipeline construction would be borne by the entity completing the project, it is still important to understand the magnitude of these avoidable costs in order to assess the impacts to the public interest. As such, I have utilized the FERC Form 6 filings of PRM and DJS to estimate of the costs of replacement pipeline construction on a per mile basis.

69. PRM has spent approximately $140.8 million to build the PRM system, with a total of 95 miles of pipeline. Using this information, the estimated cost of replicating the PRM system, in whole or in part, is approximately $1.5 MM per mile.

70. DJS has spent approximately $128.5 million to build the DJS system, with a total of 123 miles of pipeline. Using this information, the estimated cost of replicating the DJS system, in whole or in part, is approximately $1.1 MM per mile.

71. It is clear that even the partial duplication of the PRM or DJS systems will be an expensive undertaking, which can be avoided. The public interest, including public safety, health, and welfare concerns, are not enhanced by the duplication of the PRM and DJS pipeline assets that would likely occur if the PRM TSA and DJS TSA are rejected.

Potential Alternatives – Transportation by Truck

72. The second alternative identified by XOG is to transport their crude production by truck to [redacted] Truck transportation is commonly used by the industry to move smaller quantities of oil over shorter distances. An average truck holds approximately 200 barrels of oil, which is about one-third of the capacity of the average railcar. (See https://www.forbes.com/sites/jamesconca/2014/04/26/pick-your-poison-for-crude-pipeline-rail-truck-or-boat/#d8faa8717ac8) Trucking is primarily used to move oil from production sites to pipelines and or rail terminals, and also across areas where such infrastructure does not exist.

73. From a public interest perspective, statistics show that the transport of crude oil by truck is the most risky form of transport from both an accident standpoint and also from a spill standpoint. Transport of crude by truck represents the highest incident rates per billion ton-miles when compared to rail, marine vessels and pipelines. (See https://fas.org/sgp/crs/misc/R43390.pdf)

74. XOG has stated in its response to Interrogatory 3, dated September 12, 2020, that in addition to considering the use of the [redacted] and / or [redacted] the other option that it is considering (in lieu of continuing the TSAs) is trucking, which XOG states is a cost efficient option given the flexibility they would have to get to "lower cost downstream markets" presumably meaning [redacted]

Accordingly, in its interrogatory response, XOG claims that it would realize "tens of millions" of dollars in savings annually by rejecting the TSAs and contracting for an alternative transportation mechanism, such as trucking, to provide it with alternative downstream pipeline transportation options.

75. Trucking is not currently an option for all of XOG's production. As discussed above, XOG's existing Operator Agreements with the City and County of Broomfield, the City of Aurora, and the City of Commerce City all require that XOG transport the majority of their crude oil by pipeline within much of these jurisdictions. XOG's production in discovery states that trucking is not an available alternative for all pads on DJS and at least 19 pads on PRM. (See 1_XOG_PRM0000498663 and 3_XOG_PRM0000498676). Thus, even if XOG were to only truck half of their June 2020 production on PRM (approximately 16,250 barrels), it would take at least 80 trucks per day, causing increased traffic congestion and increasing overall safety risks to the public.

76. Although the DJS TSA is included in the proposed rejection motion, the DJS TSA and the DJS tariff currently include rights to deliver volumes at [redacted] there is no

reason to reject its DJS TSA. For this reason, the public interest is not, and cannot be served, through the rejection of the DJS TSA given that the production dedicated to and transported on the DJ South Gathering system would instead need to be transported by a duplicative pipeline, as XOG has stated that that trucking is not an option for their DJS dedicated production.

77. I have analyzed the costs of trucking the XOG production that is dedicated to PRM. According to documents provided in discovery by XOG, the anticipated cost of trucking is $2.25 per barrel [redacted] See XOG_PRM0000498663. This anticipated cost exceeds the current committed shipper rate on the PRM system which is $1.4732 per barrel. If we continue to assume that XOG were to truck half of their June 2020 production on PRM (approximately 16,250 barrels per day), this would result in a financial loss of nearly $400,000 per month compared to utilizing the PRM system.

78. It is clear that much of the savings that XOG is attempting to garner come at the expense of the public interest. XOG's proposed rejection of the TSAs does not consider the numerous negative impacts to the public interest resulting from the potential use of trucks instead of pipelines, nor is it clear that the rejection decision reflects the fact that XOG has agreed with several local jurisdictions that trucks would not be utilized. Based on the documents provided by XOG in discovery, they have clearly not considered the heightened potential for harm to the public interest from the use of trucks instead of pipelines. Additionally, XOG's production in discovery states that trucking is not even an available alternative for all pads on DJS and at least 19 pads on PRM. (See 1_XOG_PRM0000498663 and 3_XOG_PRM0000498676).

Potential Alternatives – Transportation by Rail

79. Another potential alternative to utilizing the PRM or DJS systems is to transport the XOG production by rail. Transportation by rail is at times used as an alternative to pipeline transportation, particularly in areas where sufficient pipeline capacity is unavailable and with long-distances between production and refineries. The construction of large new crude oil pipelines can take multiple years, whereas rail transportation is readily available in most areas of the lower 48 states.

80. The E.I.A. reports that the use of rail to transport domestic crude oil to refineries grew dramatically in the years leading up to its peak in 2014, when 133,321,000 barrels of domestic crude oil were transported by rail in the United States. Since 2014, the use of rail has been slowly declining, with 92,617,000 barrels transported by rail across the United States in 2019. See https://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=8_NA_8RCD_NUS_MBBL&f=A

81. The main competitive advantage offered by rail versus pipelines is in access to regions not served by sufficient pipeline capacity. However, long-haul transportation of crude oil by rail is more expensive than pipeline transportation on a barrel per mile basis.

82. Firstly, the existence of a crude oil rail terminal (for the loading and / or unloading of crude oil) is required for rail to be an option for producers. The price of these rail terminals can be considerable. For example, in 2014, Enbridge planned to construct an oil loading facility that was projected to cost upwards of $150 million. See https://www.wsj.com/articles/enbridge-plans-u-s-rail-loading-facility-for-crude-1406908778

83. There are four major crude oil rail terminals currently in service in Colorado, all in Weld County. These terminals are located in the towns of Hudson, Tampa, Windsor, and Carr,

respectively. See https://data.colorado.gov/Energy/Crude-Oil-Rail-Terminals-in-Colorado-2014/hb4b-8v4q

84. While these rail facilities are relatively proximate to XOG's production, there is no economic incentive for XOG to utilize these rail terminals, for two main reasons. Firstly, there are already four large competing interstate crude oil pipelines just as easily accessible to XOG at either Lucerne or Platteville. As shown in Table 1 below, all four of these pipelines offer uncommitted walk-up transportation to the major refineries and storage facilities at Cushing, Oklahoma at a cost lower than long-haul rail delivery, which is typically in the range of $10 per barrel. In comparison the current tariff rates for walk-up pipeline transportation to Cushing from Platteville to move 53,099 barrels per day are currently:

Table 1 – Interstate Pipeline Uncommitted Shipper Tariff Rates

Pipeline	Origin Point	Destination Point	Uncommitted Shipper Rate ($ per Barrel)
Grand Mesa	Lucerne, CO	Cushing, Oklahoma	$4.3861
Saddlehorn	Platteville, CO	Cushing, Oklahoma	$4.0491
White Cliffs	Platteville, CO	Cushing, Oklahoma	$3.0600
Pony Express	Platteville, CO	Cushing, Oklahoma	$4.8484

85. Secondly, in order for XOG to access the rail facilities, they would need to first truck their production from the well-pad to the rail terminal, which is not permitted from all wells. Even ignoring this prohibition, if XOG would have to truck their production, they would be better off economically by trucking to Lucerne or Platteville than to a rail terminal. Thus, there would be no net cost savings or netback improvement for XOG resulting from the utilization of rail as an alternative to its TSAs.

86. The public interest would be harmed if a crude by rail arrangement were to be made by XOG in lieu of the continued utilization of PRM and DJS. A Fraser Institute study

confirms that there are likely to be more spills when transporting a given quantity of oil over a given distance by rail than by pipeline, and there will be an even greater probability of spills if that volume is moved that same distance by truck. See https://www.fraserinstitute.org/sites/default/files/safety-in-the-transportation-of-oil-and-gas-pipelines-or-rail-rev2.pdf The National Bureau of Economic Research has also found that both air pollution and greenhouse gas costs are substantially larger for rail than for pipelines. (See https://www.nber.org/papers/w23852.pdf).

87. Thus, when compared with train (and also truck) transportation, pipelines are the preferred method of transporting oil, particularly when considering the public interest. The increased risks to public safety of a transport by rail arrangement, coupled with the decreased netbacks that would be received by XOG clearly indicate that the public interest would be harmed if XOG were to utilize a rail delivery alternative instead of a pipeline.

V. IMPLICATIONS TO PIPELINES AND DOWNSTREAM MARKETS

Financial Implications to PRM and DJS

88. The rates to utilize the PRM system and the DJS system are regulated by the FERC. The FERC requires that the transportation rates for all FERC jurisdictional crude oil pipelines be stated in each pipeline's approved tariff. Furthermore, FERC regulated crude oil pipelines are only permitted to charge shippers the filed tariff rate for transportation.

89. The currently approved tariff rate for transportation on PRM for a committed shipper is $1.4732 per barrel for deliveries from Weld County to Lucerne. The currently approved committed shipper rates for transportation on the DJS system are dependent on the receipt and delivery points utilized, as well as the number of barrels tendered. The tariff rate for a committed shipper tendering less than 25,000 barrels per day ranges from $0.95 per barrel

for deliveries to Platteville using the Matador Pipeline, to $1.7342 per barrel for deliveries using the Badger Pipeline to Lucerne.

90. Unlike a typical provider of goods or services, neither PRM nor DJS have the unilateral flexibility to lower their transportation rates at any time to meet market demands. Rather, FERC regulations required that any discounted rate offered to any shipper must also be charged to all shippers being provided the same service.

91. [redacted]

92. XOG's proposed rejection of the PRM TSA and the DJS TSA along with their plan to utilize alternative pipelines and / or trucking in lieu of PRM and DJS would cause significant financial harm to PRM and DJS. As reported on the relevant FERC Form 6Qs, total year to date revenues from crude transportation on DJS are $4.6 MM. Total year to date revenues for crude transportation on PRM are $11.6 MM, for a grand total of $16.2 MM between the two entities, an average of $2.7 MM per month, year to date. [redacted] Therefore, the rejection of these contracts, coupled with the potential by-pass of both systems will cause insurmountable financial distress and will lead PRM and DJS into insolvency. An insolvent pipeline company is not able to maintain its pipeline system or reclaim its right-

of-ways. Proactive pipeline maintenance is critical to the health and safety of the public. Without proper maintenance, underground pipelines may become subject to corrosion, which can cause the steel to lose its strength and possibly render it unable to contain the fluid in the pipeline at its operating pressure.[7] Similarly, landowner agreements may call for the reclamation of the pipeline right-of-way on private property. Reclamation may include pipe removal and the replanting of trees. Therefore, risks to the public safety would be significantly increased if PRM and DJS are driven into insolvency.

Supply Impacts to Other Pipelines

93. XOG's proposed rejection of the TSAs would potentially increase the level of available supplies to competing gathering pipeline systems located in the vicinity of PRM and / or DJS, such as the [redacted]. However, any increase would be delayed until new (and duplicative) pipelines were completed and in the interim, as discussed above, all of XOG's production on DJS would be shut in and a material portion of XOG's production on PRM would also be shut in.

94. The majority of crude oil produced in Colorado is delivered via pipeline to the Cushing Hub. As I have discussed above, in addition to Grand Mesa there are three other large interstate crude oil pipelines that deliver Colorado production to Cushing. Under each of the alternatives that I have discussed (with the exception of a shut-in of production) it is possible that XOG's production could eventually become available to one or more of these other pipelines (ultimately depending on the availability of capacity and economics). However, in the event that duplicative pipelines could not be constructed, due to permitting

[7] https://primis.phmsa.dot.gov/comm/FactSheets/FSInternalCorrosion.htm

or other economic reasons, a proportional reduction in the amount of total deliveries destined for Cushing is a possibility. Decreased availabilities of the supplies of a commodity valued by the market will cause prices to rise (all else being equal), which does not benefit the public interest.

VI. CONCLUSIONS

95. In sum, my analysis concludes that the rejection of the PRM TSA and DJS TSA will adversely impact the safety, health, and welfare of the public. These adverse impacts arise primarily from the utilization of less efficient alternatives, including (a) the shutting in of all of XOG's production that would otherwise be transported on the DJS system and a large percentage of XOG's production that would otherwise be transported on the PRM system until XOG were able to construct alternative pipelines or build the infrastructure necessary to truck its production, and (b) construction of duplicative pipelines and the transportation of crude oil by truck for some of the XOG production. Constructing duplicative pipelines consumes significant resources, including human and financial capital, while providing only limited benefit to the public. Similarly, numerous studies have shown that, when compared to pipelines, the transportation of crude oil by truck is significantly more dangerous. XOG may also face heavy resistance from cities and local communities, including through their utilization of SB 19-181, that could materially delay or prevent XOG's ability to utilize these alternatives.

96. The PRM and DJS systems have provided safe and reliable transportation to XOG and are able to continue to do so for many years to come. The continued use of PRM and DJS systems are significantly more favorable to the public interest when compared to XOG's identified alternatives.

Respectfully submitted,

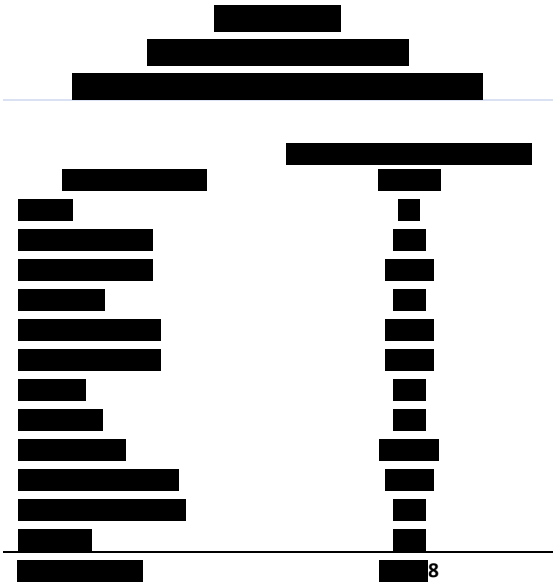


David J. Haag

September 18, 2020



Source: Enverus



Source: Enverus

Brown, Williams, Moorhead & Quinn, Inc.
Energy Consultants

CURRICULUM VITAE

NAME	David J. Haag
BUSINESS ADDRESS	1155 15th Street N.W., Suite 1004 Washington, DC 20005
PRESENT POSITION	Chief Executive Officer Brown, Williams, Moorhead & Quinn, Inc. 1155 15th Street N.W., Suite 1004 Washington, DC 20005
EDUCATION	B.A. (with Honors) in Economics with Management Minor University of Calgary, Canada
CONTINUING EDUCATION	Graduate Level Courses Public Utility Regulation and Economics New Mexico State University
TEACHING EXPERIENCE	Seminar Instructor (2013 – Present) Center for Public Utilities New Mexico State University Pipeline Ratemaking Course Seminars Taught: • Determination of a Pipeline's Cost of Service
NATURE OF WORK PERFORMED WITH FIRM	Mr. Haag joined BWMQ in September 2019 as Chief Executive Officer. Brown Williams provides thorough analytical expertise and advocacy on behalf of clients across a wide range of energy issues, including pipeline Cost of Service and Rate Design, Certificate Applications, Depreciation, and Economic Analysis. Mr. Haag is highly regarded in the natural gas pipeline industry as a pipeline cost of service, rate design, tariff, and regulatory expert, bringing to the role of CEO his extensive experience dealing with the Federal Energy Regulatory Commission, including the filing of expert testimony, management of numerous complex rate case

filings, market-based rate studies, certificate filings, compliance filings, as well as gas pipeline and storage tariff filings.

Mr. Haag has filed expert testimony and / or affidavits on various rate and regulatory matters including business risk assessment, proxy groups, capital structure, cost of service issues, rate design, cost classification, cost allocation, billing determinants, discount adjustments, market power tariffs, rate levelization, pipeline transportation values, and other rate-related issues.

Mr. Haag is well versed in Government, Public, and Stakeholder Relations, and maintains established relationships with FERC Staff as well as various industry trade associations, including the Interstate Natural Gas Association of America and the Association of Oil Pipelines.

Mr. Haag is also seasoned in the analysis of complex commercial, financial, and regulatory matters related to pipelines and storage, and is able to assist with regulatory oversight for ongoing operations, new projects, acquisitions, mergers, and divestitures.

Finally, Mr. Haag is experienced in the management of oil pipeline tariffs under the Interstate Commerce Act, including the requisite depreciation and underlying cost of service issues pertaining to oil and products pipelines.

PREVIOUS EMPLOYMENT

Prior to joining BWMQ, Mr. Haag served as Vice President, Regulatory and Chief Compliance Officer for Tallgrass Energy, LP, where he was responsible for identifying, overseeing, and implementing regulatory strategies across each Tallgrass pipeline entity, including natural gas transmission pipelines, storage facilities, and crude oil pipelines. Mr. Haag was accountable for both the management of all rate and cost of service related filings (including Section 4 Rate Case filings, FERC Form 501-G filings, expert testimony, tariff filings, and the development of complex financial modeling for strategic analysis), as well as all Tallgrass FERC Certificate matters (including filings for the construction, modification, replacement, and abandonment of pipeline facilities).

As Chief Compliance Officer, Mr. Haag was responsible for ensuring that all Tallgrass regulated business was conducted in compliance and adherence with the FERC Standards of Conduct and other applicable regulations.

In addition, Mr. Haag also served at Tallgrass as Vice President of Commercial Operations, managing the Trailblazer and Tallgrass Interstate Pipeline Systems. In this role, Mr. Haag was responsible to manage all commercial aspects of the business, including contracting, business development, and customer relationships across the two major pipelines.

Prior to joining Tallgrass, Mr. Haag served as Director of Rates for Boardwalk Pipeline Partners, L.P. where he was accountable for the various rate and cost of service matters across all regulated Boardwalk entities, including the provision of expert testimony and preparation of financial models and strategic analysis.

Mr. Haag was also previously employed as Manager, Rates and Regulatory Affairs for Portland Natural Gas Transmission, where he prepared, filed and managed all Portland regulatory filings; major filings included multiple Section 4 FERC rate case filings, FERC certificate applications, NAESB compliance filings, District Court matters, as well as the bankruptcy of a major shipper.

Earlier in his career, Mr. Haag also worked in Sales and Marketing for TransCanada Pipelines and is therefore also familiar with Canadian pipeline operations and regulations.

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	SUBJECT MATTER
			SECTION 4 RATE CASE FILINGS	
9	FERC	RP20-921	MARITIMES & NORTHEAST PIPELINE, L.L.C.	Business Risk / Proxy Group / Capital Structure
8	FERC	RP20-908	ALLIANCE PIPELINE L.P.	Business Risk / Proxy Group / Capital Structure
7	FERC	RP20-467	DOMINION ENERGY COVE POINT LNG, LP	Business Risk / Proxy Group
6	FERC	RP20-131	ENABLE MISSISSIPPI RIVER TRANSMISSION	Discount Adjustment
5	FERC	RP18-923	TRAILBLAZER PIPELINE COMPANY, LLC	Section 4 Rate Case
4	FERC	RP16-137	TALLGRASS INTERSTATE GAS TRANSMISSION, LLC	Section 4 Rate Case
3	FERC	RP15-65	GULF SOUTH PIPELINE COMPANY, LP	Section 4 Rate Case
2	FERC	RP10-729-000	PORTLAND NATURAL GAS TRANSMISSION SYSTEM	Section 4 Rate Case
1	FERC	RP08-306-000	PORTLAND NATURAL GAS TRANSMISSION SYSTEM	Section 4 Rate Case
			SECTION 7 CERTIFICATE FILINGS	
4	FERC	CP18-103	ROCKIES EXPRESS PIPELINE, LLC	Installation of 6 new compressor units
3	FERC	CP18-102	CHEYENNE CONNECTOR, LLC	70 mile large-diameter greenfield pipeline
2	FERC	CP17-485	TALLGRASS INTERSTATE GAS TRANSMISSION, LLC	Partial facility abandonment application
1	FERC	CP15-137	ROCKIES EXPRESS PIPELINE, LLC	Capacity Enhancement Project – 800,000 Dth/d pipeline system expansion

EXHIBIT M

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF DELAWARE

In re EXTRACTION OIL & GAS, INC., *et al.*, Debtors.	Bankruptcy Case No. 20-11548 (CSS) (Jointly Administered)
PLATTE RIVER MIDSTREAM, LLC AND DJ SOUTH GATHERING, LLC, Appellant, v. EXTRACTION OIL & GAS, INC., Appellee.	Civil Action No. 20-1532 (CFC)

DECLARATION OF MATTHEW B. HARVEY IN SUPPORT OF *EMERGENCY* MOTION TO STAY PENDING APPEAL

I, Matthew B. Harvey, hereby declare under penalty of perjury as follows:

1. I am a partner at the law firm of Morris, Nichols, Arsht & Tunnell LLP, co-counsel to Appellants Platte River Midstream, LLC ("PRM"), DJ South Gathering, LLC ("DJS"), and Platte River Holdings, LLC ("PRH").

2. I respectfully submit this declaration in support of the Emergency *Motion to Stay Pending Appeal* (the "Motion"), filed contemporaneously with this declaration (the "Declaration").

3. This is an emergency motion pursuant to Bankruptcy Rule 8013(d). As set out in the Motion, an oral motion for the relief requested in the Motion was made before the Bankruptcy Court and denied without the opportunity for argument, therefore remand is not required under Bankruptcy Rule 8013(d)(2)(B).

4. Pursuant to Bankruptcy Rule 8013(d)(2)(D) and Bankruptcy Rule 8011, a copy of the Motion is being served by email upon the following counsel of record to Appellee substantially contemporaneously with filing:

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5. On November 17, 2020, counsel for Appellants requested that Appellee consent to a stay pending appeal. On November 19, 2020, counsel to Appellees informed Appellant's counsel that Appellee does not consent to a stay pending appeal. Pursuant to Bankruptcy Rule 8013(d)(3), and in addition to the foregoing request, Appellants' counsel notified Appellee's counsel on November 19, 2020, of the filing of the Motion prior to filing.

I declare under penalty of perjury under that the foregoing is true and correct.

Executed on November 19, 2020
Wilmington, Delaware

/s/ Matthew B. Harvey
Matthew B. Harvey (No. 5186)
Morris, Nichols, Arsht & Tunnell LLP

EXHIBIT N

IN THE UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF DELAWARE

In re: EXTRACTION OIL & GAS, INC., *et al.*, Debtors.	Bankruptcy Case No. 20-11548 (CSS) (Jointly Administered)
PLATTE RIVER MIDSTREAM, LLC, DJ SOUTH GATHERING, LLC, AND PLATTE RIVER HOLDINGS, LLC, Appellants, v. EXTRACTION OIL & GAS, INC., Appellee.	Civil Action No. 20-1532 (CFC)

ORDER

THIS MATTER comes before the Court on Appellants Platte River Midstream, LLC ("PRM"), DJ South Gathering, LLC ("DJ South"), and Platte River Holdings, LLC's ("PRH") Emergency Motion to Stay Pending Appeal (the "Motion"). Having reviewed the parties' briefs and arguments, and the Court having found that all of the requirements for a stay pending appeal have been met, it is hereby:

ORDERED that the Motion is GRANTED; and it is further

ORDERED, that the *Order* [D.I. 1038] entered by the United States Bankruptcy Court for the District of Delaware (the "Bankruptcy Court") in Bankruptcy Case No. 20-11548 granting the motion by Appellee Extraction Oil & Gas, Inc. ("Extraction") to reject the parties' contracts under 11 U.S.C. § 365 is STAYED pending the entry of a final judgment in the above-captioned appeal.

Dated: November 19, 2020

UNITED STATES DISTRICT JUDGE

CERTIFICATE OF SERVICE

I, Brett S. Turlington, hereby certify that I am not less than 18 years of age, and that service of the foregoing Emergency *Motion to Stay Pending Appeal* was caused to be made on November 19, 2020, as indicated, on service list below.

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Date: November 19, 2020

/s/ Brett S. Turlington
Brett S. Turlington (No. 6705)