UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K

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

For the fiscal year ended December 31, 2021

or

o **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: 001-35666

Summit Midstream Partners, LP

(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)

910 Louisiana Street, Suite 4200
Houston, TX
(Address of principal executive offices)
45-5200503
(I.R.S. Employer
Identification No.)

77002
(Zip Code)
(832) 413-4770
(Registrant's telephone number, including area code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units	SMLP	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. o Yes x No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Act. o Yes x No

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. x Yes o 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).x Yes o 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	o	Accelerated filer	x
Non-accelerated filer	o	Smaller reporting company	x
Emerging growth company	o		

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. o

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes x No

The aggregate market value of the common units held by non-affiliates of the registrant as of June 30, 2021 was $204,910,000.

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

Class	As of February 15, 2022
Common Units	10,023,709

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement relating to its 2022 Annual Meeting of Limited Partners, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2021, are incorporated by reference into Part III of this Annual Report on Form 10-K where indicated.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Investors are cautioned that certain statements contained in this report as well as in periodic press releases and certain oral statements made by our officers and employees during our presentations are “forward-looking” statements. Forward-looking statements include, without limitation, any statement that may project, indicate or imply future results, events, performance or achievements and may contain the words “expect,” “intend,” “plan,” “anticipate,” “estimate,” “believe,” “will be,” “will continue,” “will likely result,” and similar expressions, or future conditional verbs such as “may,” “will,” “should,” “would,” and “could.” In addition, any statement concerning future financial performance (including future revenues, earnings or growth rates), ongoing business strategies or prospects, and possible actions taken by us or our subsidiaries are also forward-looking statements. These forward-looking statements involve various risks and uncertainties, including, but not limited to, those described in Item 1A. Risk Factors included in this Annual Report on Form 10-K (this “Annual Report”).

Forward-looking statements are based on current expectations and projections about future events and are inherently subject to a variety of risks and uncertainties, many of which are beyond the control of our management team. All forward-looking statements in this report and subsequent written and oral forward-looking statements attributable to us, or to persons acting on our behalf, are expressly qualified in their entirety by the cautionary statements in this paragraph. These risks and uncertainties include, among others:

- our decision whether to pay, or our ability to grow, our cash distributions;
- fluctuations in natural gas, NGLs and crude oil prices, including as a result of political or economic measures taken by various countries or OPEC;
- the extent and success of our customers' drilling and completion efforts, as well as the quantity of natural gas, crude oil and produced water volumes produced within proximity of our assets;
- the current and potential future impact of the COVID-19 pandemic on our business, results of operations, financial position or cash flows;
- failure or delays by our customers in achieving expected production in their natural gas, crude oil and produced water projects;
- competitive conditions in our industry and their impact on our ability to connect hydrocarbon supplies to our gathering and processing assets or systems;
- actions or inactions taken or nonperformance by third parties, including suppliers, contractors, operators, processors, transporters and customers, including the inability or failure of our shipper customers to meet their financial obligations under our gathering agreements and our ability to enforce the terms and conditions of certain of our gathering agreements in the event of a bankruptcy of one or more of our customers;
- our ability to divest of certain of our assets to third parties on attractive terms, which is subject to a number of factors, including prevailing conditions and outlook in the natural gas, NGL and crude oil industries and markets;
- the ability to attract and retain key management personnel;
- commercial bank and capital market conditions and the potential impact of changes or disruptions in the credit and/or capital markets;
- changes in the availability and cost of capital and the results of our financing efforts, including availability of funds in the credit and/or capital markets;
- restrictions placed on us by the agreements governing our debt and preferred equity instruments;
- the availability, terms and cost of downstream transportation and processing services;
- natural disasters, accidents, weather-related delays, casualty losses and other matters beyond our control;
- operational risks and hazards inherent in the gathering, compression, treating and/or processing of natural gas, crude oil and produced water;
- our ability to comply with the terms of the agreements comprising the Global Settlement;
- weather conditions and terrain in certain areas in which we operate;
- physical and financial risks associated with climate change;
- any other issues that can result in deficiencies in the design, installation or operation of our gathering, compression, treating and processing facilities;

- timely receipt of necessary government approvals and permits, our ability to control the costs of construction, including costs of materials, labor and rights-of-way and other factors that may impact our ability to complete projects within budget and on schedule;
- our ability to finance our obligations related to capital expenditures, including through opportunistic asset divestitures or joint ventures and the impact any such divestitures or joint ventures could have on our results;
- the effects of existing and future laws and governmental regulations, including environmental, safety and climate change requirements and federal, state and local restrictions or requirements applicable to oil and/or gas drilling, production or transportation;
- changes in tax status;
- the effects of litigation;
- changes in general economic conditions; and
- certain factors discussed elsewhere in this report.

Developments in any of these areas could cause actual results to differ materially from those anticipated or projected or cause a significant reduction in the market price of our common units, preferred units and senior notes.

The foregoing list of risks and uncertainties may not contain all of the risks and uncertainties that could affect us. In addition, in light of these risks and uncertainties, the matters referred to in the forward-looking statements contained in this document may not in fact occur. Accordingly, undue reliance should not be placed on these statements. We undertake no obligation to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise, except as otherwise required by law.

Risk Factors Summary

This summary briefly lists the principal risks and uncertainties facing our business, which are only a select portion of those risks. A more complete discussion of those risks and uncertainties is set forth in Part I, Item 1A of this Annual Report. Additional risks not presently known to us or that we currently deem immaterial may also affect us. If any of these risks occur, our business, financial condition or results of operations could be materially and adversely affected.

Our business is subject to the following principal risks and uncertainties:

Risks Related to COVID-19

- The COVID-19 pandemic, coupled with other pressures on oil and gas prices has had, and is expected to continue to have, an adverse impact on our business, results of operations, financial position and cash flows.

Risks Related to Our Operations

- We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses to enable us to pay distributions to holders of our preferred units and common units.
- We depend on a relatively small number of customers for a significant portion of our revenues.
- We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties and any material nonpayment or nonperformance by one or more of these parties could materially adversely affect our financial and operating results.
- Adverse developments in our areas of operation could materially adversely impact our financial condition, results of operations, cash flows and ability to make cash distributions to our unitholders.
- Significant prolonged weakness in natural gas, NGL and crude oil prices could reduce throughput on our systems and materially adversely affect our revenues and ability to make cash distributions to our unitholders.
- Because of the natural decline in production from our customers' existing wells, our success depends in part on our customers replacing declining production and also on our ability to maintain levels of throughput on our systems.
- Customers may not drill and complete wells on the acreage behind our systems, which could adversely impact the levels of throughput on our systems.
- Any significant decrease in the demand for natural gas and crude oil, including de-carbonization initiatives, could reduce the volumes of natural gas and crude oil that we gather and process, which could adversely affect our business and operating results.

- We may not be able to renew or replace expiring contracts at favorable rates or on a long term basis.
- Our ability to operate our business effectively could be impaired if we fail to attract and retain key personnel.

Risks Related to Our Finances

- Limited access to and/or availability of the commercial bank market, debt and equity capital markets could impair our ability to grow or cause us to be unable to meet future capital requirements.
- Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects, and may limit our flexibility to obtain financing and to pursue other business opportunities.
- We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness or to refinance, which may not be successful.
- Restrictions in our debt instruments could materially adversely affect our business, financial condition, results of operations, our ability to make cash distributions to unitholders and the value of our common units.
- Inflation could have adverse effects on our results of operation.
- An increase in interest rates will cause our debt service obligations to increase.
- A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.
- We have in the past and may in the future incur losses due to impairment in the carrying value of our long-lived assets or equity method investments.

Regulatory and Environmental Policy Risks

- A change in laws and regulations applicable to our assets or services, or the interpretation or implementation of existing laws and regulations may cause our revenues to decline or our operation and maintenance expenses to increase.
- Increased regulation of hydraulic fracturing could result in reductions or delays in customer production, which could materially adversely impact our revenues.
- We are subject to FERC jurisdiction, federal anti-market manipulation laws and regulations, potentially other federal regulatory requirements and state and local regulation, and could be materially affected by changes in such laws and regulations, or in the way they are interpreted and enforced.
- We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.
- Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the services we provide.
- We may face opposition to the development, permitting, construction or operation of our pipelines and facilities from various groups.
- Our business is subject to complex and evolving U.S. and international laws and regulations regarding privacy and data protection.

Risks Inherent in an Investment in Us

- Because our common units are yield-oriented securities, increases in interest rates could materially adversely impact our unit price, ability to issue equity or incur debt and ability to make cash distributions to unitholders.
- Our Partnership Agreement replaces our General Partner’s fiduciary duties to unitholders and those of our officers and directors with contractual standards governing their duties.
- We may issue additional units without unitholder approval, which would dilute existing ownership interests.

Tax Risks

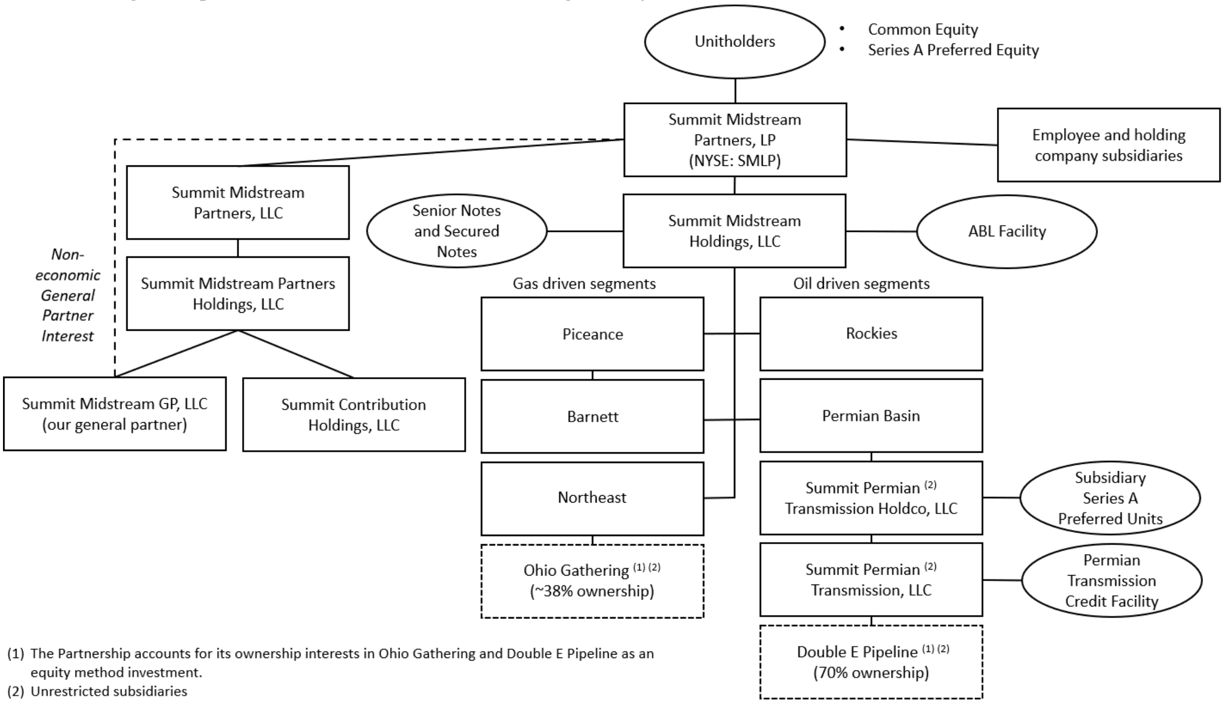
- If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.
- If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.
- Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us.
- We have engaged in recent transactions that generated substantial cancellation of debt (“COD”) income on a per unit basis relative to the trading price of our common units. We may engage in other transactions that result in substantial COD income or other gains in the future, and such events may cause a unitholder to be allocated income with respect to our units with no corresponding distribution of cash to fund the payment of the resulting tax liability to the unitholder.

Risks Related to Terrorism and Cyberterrorism

- Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.
- Our operations depend on the use of information technology systems that could be the target of a cyberattack.

ORGANIZATIONAL CHART

The following chart provides a summarized view of our legal entity structure at December 31, 2021:



(1) The Partnership accounts for its ownership interests in Ohio Gathering and Double E Pipeline as an equity method investment.
(2) Unrestricted subsidiaries

COMMONLY USED OR DEFINED TERMS

2015 Blacktail Release	a 2015 rupture of our four-inch produced water gathering pipeline near Williston, North Dakota
2022 Senior Notes	Summit Holdings' and Finance Corp.’s 5.5% senior unsecured notes due August 2022
2025 Senior Notes	Summit Holdings' and Finance Corp.’s 5.75% senior unsecured notes due April 2025
2026 Secured Notes	Summit Holdings' and Finance Corp.’s 8.500% senior secured second lien notes due 2026
2026 Secured Notes Indenture	Indenture, dated as of November 2, 2021, by and among Summit Holdings, Finance Corp., the guarantors party thereto and Regions Bank, as trustee
ABL Facility	the asset-based lending credit facility governed by the ABL Agreement
ABL Agreement	Loan and Security Agreement, dated as of November 2, 2021, among Summit Holdings, as borrower, SMLP and certain subsidiaries from time to time party thereto, as guarantors, Bank of America, N.A., as agent, ING Capital LLC, Royal Bank of Canada and Regions Bank, as co-syndication agents, and Bank of America, N.A., ING Capital LLC, RBC Capital Markets and Regions Capital Markets, as joint lead arrangers and joint bookrunners
AMI	area of mutual interest; AMIs require that any production from wells drilled by our customers within the AMI be shipped on and/or processed by our gathering systems
associated natural gas	a form of natural gas which is found with deposits of petroleum, either dissolved in the crude oil or as a free gas cap above the crude oil in the reservoir
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
Audit Committee	the audit committee of the Board of Directors
Bbl	one barrel; used for crude oil and produced water and equivalent to 42 U.S. gallons
Bcf	one billion cubic feet
Bcfe/d	the equivalent of one billion cubic feet per day; generally calculated when liquids are converted into natural gas; determined using a ratio of six thousand cubic feet of natural gas to one barrel of liquids
Bison Midstream	Bison Midstream, LLC
Board of Directors	the board of directors of our General Partner
CAA	Clean Air Act
CEA	Commodity Exchange Act
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFTC	Commodity Futures Trading Commission
COD	cancellation of debt
Collateral Agreement	Collateral Agreement, dated as of November 2, 2021, by and among SMLP, as a pledgor, Summit Holdings and Finance Corp., as pledgors and grantors, the subsidiary guarantors party therein, and Regions Bank, as collateral agent
Compensation Committee	the compensation committee of the Board of Directors
condensate	a natural gas liquid with a low vapor pressure, mainly composed of propane, butane, pentane and heavier hydrocarbon fractions
Conflicts Committee	the conflicts committee of the Board of Directors
Co-Issuers	Summit Holdings and Finance Corp.
CWA	Clean Water Act
Debt Tender Offers	the September 2020 cash tender offers by the Co-Issuers to purchase a portion of their 2022 Senior Notes and 2025 Senior Notes
DFW Midstream	DFW Midstream Services LLC
DJ Basin	Denver-Julesburg Basin
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
DOT	U.S. Department of Transportation
Double E	Double E Pipeline, LLC

Double E Pipeline	a 1.35 Bcf per day, FERC-regulated interstate natural gas transmission pipeline that commenced operations in November 2021 and provides transportation service from multiple receipt points in the Delaware Basin to various delivery points in and around the Waha hub in Texas
Double E Project	the development and construction of the Double E Pipeline
dry gas	natural gas primarily composed of methane where heavy hydrocarbons and water either do not exist or have been removed through processing or treating
Dth/d	one million British Thermal Units per day
ECP	Energy Capital Partners II, LLC and its parallel and co-investment funds
EPA	Environmental Protection Agency
Epping	Epping Transmission Company, LLC
Epping Pipeline	an interstate crude oil pipeline in North Dakota, owned and operated by Epping
Equity Restructuring	a series of transactions consummated on March 22, 2019, pursuant to which the Partnership cancelled its IDRs and converted its 2% economic GP interest to a non-economic GP interest in exchange for 8,750,000 SMLP common units, which were issued to SMP Holdings
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Finance Corp.	Summit Midstream Finance Corp.
FTC	Federal Trade Commission
GAAP	accounting principles generally accepted in the United States of America
General Partner	Summit Midstream GP, LLC
GHG	greenhouse gas(es)
GP	general partner
GP Buy-In Transaction	the transactions contemplated by the Purchase Agreement dated May 3, 2020, between the Partnership and the affiliates of its then private equity sponsor, ECP, to acquire Summit Investments
GP interest	2.0% general partner interest of GP in the Partnership prior to the Equity Restructuring and a non-economic general partner interest after the Equity Restructuring
Grand River	Grand River Gathering, LLC
Guarantor Subsidiaries	Bison Midstream and its subsidiaries, Grand River and its subsidiaries, DFW Midstream, Summit Marketing, Summit Permian, Permian Finance, OpCo, Summit Utica, Meadowlark Midstream, Summit Permian II, Mountaineer Midstream, Epping, Red Rock, Polar Midstream and Summit Niobrara
Hub	geographic location of a storage facility and multiple pipeline interconnections
ICA	Interstate Commerce Act
IDRs	incentive distribution rights
Intercreditor Agreement	Intercreditor Agreement, dated as of November 2, 2021, by and among Bank of America, N.A., as first lien representative and collateral agent for the initial first lien claimholders, Regions Bank, as second lien representative for the initial second lien claimholders and as collateral agent for the initial second lien claimholders, acknowledged and agreed to by Summit Holdings and the other grantors referred to therein
IRS	Internal Revenue Service
LIBOR	London Interbank Offered Rate
Mbbl/d	one thousand barrels per day
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Meadowlark Midstream	Meadowlark Midstream Company, LLC
MMBtu	one million British Thermal Units
MMcf	one million cubic feet
MMcf/d	one million cubic feet per day
MMcfe/d	the equivalent of one million cubic feet per day; determined using a ratio of six thousand cubic feet of natural gas to one barrel of liquids
Mountaineer Midstream	Mountaineer Midstream Company, LLC

MVC	minimum volume commitment
NAAQS	national ambient air quality standard
NEPA	National Environmental Policy Act
NDIC	North Dakota Industrial Commission
NGA	Natural Gas Act
NGLs	natural gas liquids; the combination of ethane, propane, normal butane, iso-butane and natural gasolines that when removed from unprocessed natural gas streams become liquid under various levels of higher pressure and lower temperature
NGPA	Natural Gas Policy Act of 1978
Niobrara G&P	Niobrara Gathering and Processing system
Non-Guarantor Subsidiaries	Permian Holdco and Summit Permian Transmission
NYSE	New York Stock Exchange
Obligor Group	the Co-Issuers and the Guarantor Subsidiaries
OCC	Ohio Condensate Company, L.L.C.
OGC	Ohio Gathering Company, L.L.C.
Ohio Gathering	Ohio Gathering Company, L.L.C. and Ohio Condensate Company, L.L.C.
OPA	Oil Pollution Control Act
OpCo	Summit Midstream OpCo, LP
Open Market Repurchases	the open market repurchases of the 2022 Senior Notes and the 2025 Senior Notes
PHMSA	Pipeline and Hazardous Materials Safety Administration
play	a proven geological formation that contains commercial amounts of hydrocarbons
Permian Finance	Summit Midstream Permian Finance, LLC
Permian Holdco	Summit Permian Transmission Holdco, LLC
Permian Transmission Credit Facility	the credit facility governed by the Credit Agreement, dated as of March 8, 2021, among Summit Permian Transmission, LLC, as borrower, MUFG Bank Ltd., as administrative agent, Mizuho Bank (USA), as collateral agent, ING Capital LLC, Mizuho Bank, Ltd. and MUFG Union Bank, N.A., as L/C issuers, coordinating lead arrangers and joint bookrunners, and the lenders from time-to-time party thereto
Polar and Divide	the Polar and Divide system; collectively Polar Midstream and Epping
Polar Midstream	Polar Midstream, LLC
produced water	water from underground geologic formations that is a by-product of natural gas and crude oil production
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
Red Rock Gathering	Red Rock Gathering Company, LLC
Revolving Credit Facility	the senior secured revolving credit facility governed by the Fourth Amended and Restated Credit Agreement dated as of December 18,2020, as amended by the Third Amended and Restated Credit Agreement dated as of May 26, 2017, as amended by the First Amendment to Third Amended and Restated Credit Agreement dated as of September 22, 2017, the Second Amendment to Third Amended and Restated Credit Agreement dated as of June 26, 2019 and the Third Amendment to Third Amended and Restated Credit Agreement dated as of December 24, 2019
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
segment adjusted EBITDA	total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) our proportional adjusted EBITDA for equity method investees, (iii) depreciation and amortization, (iv) adjustments related to MVC shortfall payments, (v) adjustments related to capital reimbursement activity, (vi) unit- based and noncash compensation, (vii) impairments and (viii) other noncash expenses or losses, less other noncash income or gains
Series A Preferred Units	Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units

shortfall payment	the payment received from a counterparty when its volume throughput does not meet its MVC for the applicable period
SMLP	Summit Midstream Partners, LP
SMLP Holdings	SMLP Holdings, LLC
SMLP LTIP	SMLP Long-Term Incentive Plan
SMP Holdings	Summit Midstream Partners Holdings, LLC, also known as SMPH
SMPH Term Loan	SMPH Holdings’ term loan, governed by the Term Loan Agreement, dated as of March 21, 2017, among SMP Holdings, as borrower, the lenders party thereto and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent and Collateral Agent
SPCC	Spill Prevention Control and Countermeasure
Subsidiary Series A Preferred Units	Series A Fixed Rate Cumulative Redeemable Preferred Units issued by Permian Holdco
Summit Holdings	Summit Midstream Holdings, LLC
Summit Investments	Summit Midstream Partners, LLC
Summit Niobrara	Summit Midstream Niobrara, LLC
Summit Marketing	Summit Midstream Marketing, LLC
Summit Permian	Summit Midstream Permian, LLC
Summit Permian II	Summit Midstream Permian II, LLC
Summit Permian Transmission	Summit Permian Transmission, LLC
Summit Utica	Summit Midstream Utica, LLC
Tax Reform Legislation	the Tax Cuts and Jobs Act of 2017
Tcfe	the equivalent of one trillion cubic feet
the Partnership	Summit Midstream Partners, LP and its subsidiaries
the Partnership Agreement	the Fourth Amended and Restated Agreement of Limited Partnership of the Partnership dated May 28, 2020
throughput volume	the volume of natural gas, crude oil or produced water gathered, transported or passing through a pipeline, plant or other facility during a particular period; also referred to as volume throughput
Tioga Midstream	Tioga Midstream, LLC
TL Restructuring	the November 2020 consensual debt discharge and restructuring of the SMPH Term Loan
unconventional resource basin	a basin where natural gas or crude oil production is developed from unconventional sources that require hydraulic fracturing as part of the completion process, for instance, natural gas produced from shale formations and coalbeds; also referred to as an unconventional resource play
VOC	volatile organic compound(s)
wellhead	the equipment at the surface of a well, used to control the well's pressure; also, the point at which the hydrocarbons and water exit the ground

PART I

The GP Buy-In Transaction (as defined below) occurred in May 2020, whereby the Partnership acquired Summit Investments, the privately-held parent company of the General Partner, and the General Partner became a wholly-owned subsidiary of the Partnership. Under GAAP, the GP Buy-In Transaction was deemed a transaction between entities under common control with a change in reporting entity. As a result of the GP Buy-In Transaction, the Partnership recast its historical financial statements for the periods preceding the GP Buy-In Transaction, during which the entities were under the common control of Summit Investments, to retrospectively reflect the GP Buy-In Transaction. Although the Partnership was the surviving entity for legal purposes, Summit Investments was the surviving entity for accounting purposes; therefore, the historical financial results of the Partnership prior to the GP Buy-In Transaction are those of Summit Investments. Prior to the GP Buy-In Transaction, Summit Investments controlled the Partnership and, as such, the Partnership's financial statements were consolidated into Summit Investments.

The financial data included in this Annual Report includes periods prior to the GP Buy-In Transaction. Consequently, the Partnership's consolidated financial statements have been retrospectively recast for all periods presented in order to present the financial results of the surviving entity, Summit Investments, for accounting purposes.

ITEM 1. BUSINESS

Summit Midstream Partners, LP, a Delaware limited partnership (including its subsidiaries, collectively, "we", "our", "us", "SMLP", or "the Partnership"), is a value-driven limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in unconventional resource basins, primarily shale formations, in the continental United States. Our common units are listed and traded on the NYSE under the ticker symbol "SMLP."

The Partnership was formed in May 2012. The Partnership's executive offices are located at 910 Louisiana Street, Suite 4200, Houston, Texas 77002, and can be reached by phone at 832-413-4770. The Partnership also maintains regional field offices in close proximity to our areas of operation to support the operation and development of our midstream assets.

As a result of the GP Buy-In Transaction, the Partnership indirectly owns its General Partner, and the General Partner's Board of Directors is comprised of a majority of independent directors. The Partnership's Fourth Amended and Restated Agreement of Limited Partnership (the "Partnership Agreement") provides the Partnership's common unitholders with voting rights in the election of the members of the General Partner's Board of Directors on a staggered basis beginning in 2022.

Our Business Strategies

We operate a differentiated midstream platform that is built for long-term, sustainable value creation. Our integrated assets are strategically located in production basins including the Williston Basin, DJ Basin, Utica Shale, Marcellus Shale, Barnett Shale, Piceance Basin and Permian Basin. Our primary business objective is to maximize cash flow and provide cash flow stability for our stakeholders while growing prudently and profitably. We intend to accomplish this objective by executing the following strategies:

- ***Capital structure optimization***. We seek to maximize unitholder value. Our capital structure currently consists of common equity, preferred equity, and indebtedness that is comprised of borrowings, a portion of which is secured by substantially all of the Partnership's assets. The Partnership intends to optimize its capital structure in the future by reducing its indebtedness with free cash flow and when appropriate, it may pursue opportunistic capital markets transactions with the objective of increasing long term unitholder value.
- ***Portfolio management***. We seek to maximize unitholder value by strategically managing our portfolio of midstream assets and allocating capital based on appropriate risk-informed cash flow assumptions. This may include opportunistic divestitures, re-allocation of capital to new or existing areas, and development of joint ventures involving our existing midstream assets or new investment opportunities.
- ***Maintaining our focus on fee-based revenue with minimal direct commodity price exposure***. We intend to maintain our focus on providing midstream services under primarily long-term and fee-based contracts. We believe that our focus on fee-based revenues with minimal direct commodity price exposure is essential to maintaining stable cash flows.
- ***Maintaining strong producer relationships to maximize utilization of all of our midstream assets***. We have cultivated strong producer relationships by focusing on customer service and reliable project execution and by operating our assets safely and reliably over time. We believe that our strong producer relationships will create future opportunities to expand our gathering reach and optimize the utilization of our gathering systems for our customers.
- ***Continuing to prioritize safe and reliable operations***. We believe that providing safe, reliable and efficient operations is a key component of our business strategy. We place a strong emphasis on employee training,

operational procedures and enterprise technology, and we intend to continue promoting a high standard with respect to the efficiency of our operations and the safety of all of our constituents.

Recent Developments and Highlights

The following is a brief listing of significant developments and highlights since December 31, 2020. Additional information regarding these items may be found elsewhere in this Annual Report.

- ***Refinanced $959.0 million of debt maturing in 2022.*** In November 2021, we refinanced $959.0 million of indebtedness that was scheduled to mature in 2022 through a series of transactions that involved issuing $700.0 million of our 8.500% Senior Secured Second Lien Notes due 2026 (the "2026 Secured Notes") and entering into a new $400.0 million first-lien, asset-based revolving credit facility that matures on May 1, 2026. The extension of our debt maturities provides us with additional financial flexibility to further reduce indebtedness and execute on our corporate objectives. See Note 8 – Debt for further details.
- ***Reduced net indebtedness by $124.0 million in 2021 and $432.3 million since the GP Buy-In Transaction.*** Using cash flow from operations and other corporate initiatives, we reduced our net indebtedness by $124.0 million during 2021 (which excludes borrowings under our non-recourse Permian Transmission Credit Facilities) and since the GP Buy-In Transaction in 2020, we have reduced our net indebtedness by $432.3 million (excludes borrowings under our non-recourse Permian Transmission Credit Facilities). See Note 8 – Debt for further details.
- ***Placed Double E Pipeline in service at an estimated $70 million below our cost estimate, net to Summit.*** In November 2021, we placed the Double E Pipeline in service at a total estimated cost to us of approximately $280.0 million for our 70% interest in Double E (including $11.0 million of carryover capital contributions to be made to Double E during each of the quarterly periods ending March 31 and June 30, 2022). The final cost to complete Double E was approximately $70.0 million below our final investment decision cost estimate of approximately $350.0 million, in each case net to Summit, and these cost savings significantly enhance our Double E investment returns.
- ***Reduced Series A Preferred Unit securities below $100.0 million parity threshold.*** In March 2021 and December 2021, the Partnership launched a series of transactions to exchange its Series A Preferred Units for newly issued SMLP common units, whereby we exchanged an aggregate of 96,061 Series A Preferred Units for 3,392,590 SMLP common units, net of units withheld for withholding taxes. We now have Series A Preferred Units outstanding with less than $100.0 million liquidation preference, in the aggregate, and as a result we may issue unlimited additional parity preferred equity securities in our capital structure without a vote of the holders of the Series A Preferred Units. We believe the ability to issue or assume additional parity preferred equity securities enhances our financial flexibility to execute our business objectives and pursue value-enhancing growth opportunities. See Note 12 - Partners' Capital and Mezzanine Capital and Note 19 – Subsequent Events for additional information.
- ***Resolved longstanding environmental matter.*** As previously disclosed, we were the subject of multiple government investigations stemming from a 2015 rupture of our four-inch produced water gathering pipeline near Williston, North Dakota ("2015 Blacktail Release"). On August 4, 2021, we entered into a Global Settlement to resolve these matters that includes the payment of penalties and fines of $36.3 million over a period of six years. We believe that entering into a Global Settlement was in the best interest of all stakeholders, including our unitholders. See Note 10 – Commitments and Contingencies for additional information.

Our Midstream Assets

Our midstream assets primarily gather natural gas produced from pad sites, wells and central receipt points connected to our systems. Gathered natural gas volumes are then compressed, dehydrated, treated and/or processed for delivery to downstream pipelines serving processing plants or end users. We also contract with producers to gather crude oil and produced water from wells connected to our systems for delivery to downstream pipelines and to third-party rail terminals in the case of crude oil and to third-party disposal wells in the case of produced water. We generally refer to most of the services our systems provide as gathering services. We also provide natural gas transmission services via Double E, a long-haul natural gas pipeline in which Summit indirectly owns a 70% equity interest and serves as the pipeline's operator. Double E provides natural gas transportation services from multiple receipt points in the Permian Basin to various delivery points in and around the Waha hub in Texas.

Reportable Segments. In 2021, we changed our segment reporting to align with how the General Partner's Chief Executive Officer, its chief operating decision maker, reviews financial information in order to allocate resources and assess performance. The new segment reporting resulted from changes enacted to optimize commercial efforts and our geographic workforce to better align our commercial, engineering, and operational capabilities.

The five reportable segments are below along with a management categorization of the primary commodity driving customer drilling and completion decisions for each segment:

- ***Oil price driven.*** Our cash flows in the Rockies and Permian segments are primarily influenced by the prevailing price of crude oil because the drilling and completion decisions by our customers in these segments are based on well economics most heavily tied to crude oil prices. Our customers' decisions to drill and complete wells in these segments therefore result in higher volume throughput and cash flows for our midstream assets in which we collect fixed fees for gathering or processing hydrocarbons, gathering produced water, or transporting residue natural gas.
    - **Rockies** – Includes our wholly owned midstream assets located in the Williston Basin and the DJ Basin.
    - **Permian** – Includes our wholly owned midstream assets located in the Permian Basin and our equity method investment in Double E.
- ***Natural gas price driven.*** Our cash flows in the Northeast, Piceance and Barnett segments are primarily influenced by the prevailing price of natural gas because the drilling, completion and recompletion decisions by our customers in these segments are based on well economics most heavily tied to natural gas and NGL prices. Our customers' decisions to drill, complete or recomplete wells in these segments therefore result in higher throughput and cash flows for those segments in which we collect fixed fees for gathering natural gas.
    - **Northeast** – Includes our wholly owned midstream assets located in the Utica and Marcellus shale plays and our equity method investment in Ohio Gathering that is focused on the Utica Shale.
    - **Piceance** – Includes our wholly owned midstream assets located in the Piceance Basin.
    - **Barnett** – Includes our wholly owned midstream assets located in the Barnett Shale.

Industry Overview and Commercial Arrangements

We compete with other midstream companies, producers and intrastate and interstate pipelines. Competition for volumes is primarily based on reputation, commercial terms, acreage dedications, service levels, access to end-use markets, geographic proximity of existing assets to a producer's acreage and available gathering and processing capacity. We may also face competition to gather production outside of our AMIs and attract producer volumes to our gathering systems.

We earn revenue by providing gathering, compression, treating and/or processing services pursuant to primarily long-term and fee-based gathering and processing agreements with some of the largest and most active producers in North America. Through our equity method investment in the Double E Pipeline, we earn revenue by providing high pressure transportation services, as both firm and interruptible service, for residue natural gas in the Permian Basin. The fee-based nature of these agreements enhances the stability of our cash flows by limiting our direct commodity price exposure.

The significant features of our transportation and gathering and processing agreements, and the gathering and transportation systems to which they relate, are discussed in more detail below. For additional operating and financial performance information, on a consolidated basis and by reportable segment, see the "Results of Operations" section in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Areas of Mutual Interest. The vast majority of our gathering and processing agreements contain AMIs, some of which extend through 2036. The AMIs generally require that any production by our customers within the AMIs will be gathered and/or processed by our assets. In general, our customers have not leased acreage that cover our entire AMIs but, to the extent that they have leased acreage within our AMI, or lease additional acreage within our AMIs, any production from wells within that AMI will be dedicated to our systems.

Under certain of our gathering agreements, we have agreed to construct pipeline laterals to connect our gathering systems to producer pad sites located within the AMI. However, in certain circumstances we may choose not to pursue a pad connection opportunity presented by a customer if we believe that the investment would not meet our internal return expectations. Under this scenario, the customer may, in certain circumstances, construct the gathering infrastructure itself and sell it to us at a price equal to their cost plus an applicable profit margin, or, in some cases, we may release the relevant acreage dedication from the AMI.

Our AMIs cover approximately 3.0 million surface acres in the aggregate, which includes more than 0.8 million surface acres associated with Ohio Gathering.

Minimum Volume Commitments. Certain of our gathering and/or processing agreements contain MVCs which, like AMIs, benefit from the development and ongoing operation of a gathering system because they provide a minimum contracted monthly or annual revenue stream. Some of our MVCs extend through 2026. To the extent a customer does not meet its contractual MVC, it is obligated to make an MVC shortfall payment to us to cover the shortfall of required volume throughput not shipped or processed, either on a monthly or annual basis. We have designed our MVC provisions to ensure that we will generate a minimum amount of revenue from each customer over the life of the associated gathering and/or processing agreement, by either collecting gathering or processing fees on actual throughput or from cash payments to cover any MVC shortfall.

As of December 31, 2021, we had remaining MVCs totaling 1.0 Tcfe, our MVCs had a weighted-average remaining life of 4.3 years, and these MVC's average approximately 562 MMcfe/d through 2026.

For additional information on our MVCs, see Note 3 – Revenue and Note 7 – Deferred Revenue to the consolidated financial statements.

Throughput and Commodity Price Exposure. Our financial results are primarily driven by volume throughput across our gathering systems and by expense management. During 2021, aggregate natural gas volume throughput averaged 1,356 MMcf/d and crude oil and produced water volume throughput averaged 63 Mbbl/d. A majority of the volumes that we gather, compress, treat and/or process have a fixed-fee rate structure, which enhances the stability of our cash flows by providing a revenue stream that is not subject to direct commodity price risk or volatility. We also earn a portion of our revenues from the following activities that directly expose us to fluctuations in commodity prices: (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds or other processing arrangements with certain of our customers in the Rockies, Permian, and Piceance segments, (ii) the sale of natural gas we retain from certain Barnett customers, (iii) the sale of condensate we retain from our gathering services in the Piceance segment and (iv) additional gathering fees that are tied to performance of certain commodity price indexes, which are then added to the fixed gathering rates. During the year ended December 31, 2021, these additional activities accounted for approximately 22% of total revenues.

Equity Method Investment – Ohio Gathering. We have an equity method investment in Ohio Gathering, which comprises a natural gas gathering system and condensate stabilization facility located in the core of the Utica Shale in southeastern Ohio. Our joint venture partner in Ohio Gathering may elect to fund 100% of the capital calls if we choose not to fund our proportionate share of a given capital call. In 2021, we chose to not fund capital calls in Ohio Gathering because the investment did not meet our corporate objectives and as a result, our ownership interest in that venture was reduced from 38.2% as of December 31, 2020 to 37.8% as of December 31, 2021. MPLX LP (“MPLX”) is the operator of the Ohio Gathering joint venture and our joint venture partner.

Equity Method Investment – Double E. We have an equity method investment in Double E, a 1.35 Bcf/d FERC-regulated interstate natural gas transmission pipeline that commenced operations in November 2021and provides transportation service from multiple receipt points in the Delaware Basin to various delivery points in and around the Waha hub in Texas. We are the operator of the joint venture and have made all required capital contributions to Double E. As of December 31, 2021, the Partnership owns a 70% interest in Double E.

Overview of our Segments

Northeast.

The following table provides operating information regarding our Northeast reportable segment as of December 31, 2021.

	Aggregate throughput capacity (MMcf/d)	Average daily MVCs through 2026 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years)	Weighted-average remaining MVC life (Years)
Northeast	1,770	n/a	n/a	9.0	n/a

Our Northeast segment is comprised of our Summit Utica system, our Mountaineer Midstream system, and our equity method investments in Ohio Gathering.

Summit Utica system. The Summit Utica system is a natural gas gathering system located in Belmont and Monroe counties in southeastern Ohio and serves producers targeting the dry gas reserves of the Utica and Point Pleasant shale formations. The Summit Utica system gathers and delivers natural gas, primarily under long-term, fee-based gathering agreements, which include acreage dedications. XTO and Ascent are the key customers of Summit Utica and the AMIs from our customers for this system cover approximately 87,000 surface acres in the aggregate.

We have connected a substantial number of our customers' pad sites to our Summit Utica system and we expect to benefit from incremental volumes arising from drilling and completion activity that is occurring and will continue to occur on new and previously connected pad sites in our service area. Over time, we intend to expand our midstream service offerings for the Summit Utica system to connect additional customer pad sites and install centralized compression facilities. Centralized compression services have been dedicated to us in our gathering agreements and will eventually constitute a new revenue stream from our customers; however, to date, this service has not been required given the relatively high downhole pressures exhibited by dry gas wells in the Utica Shale compared to other unconventional shale plays.

The Summit Utica system interconnects with the Ohio River System pipeline, which provides access to the Clarington Hub and Rover Pipeline.

Mountaineer Midstream system. The Mountaineer Midstream system, within the Marcellus shale, is located in Doddridge and Harrison counties in West Virginia where it gathers natural gas under a long-term, fee-based contract with Antero Resources Corporation ("Antero"), which is targeting liquids-rich natural gas production from the Marcellus Shale formation in the Appalachian Basin. Volume throughput on the Mountaineer Midstream system is underpinned by minimum revenue commitments from Antero.

The Mountaineer Midstream system consists of a high-pressure natural gas gathering system and two compressor stations. This system gathers high-pressure natural gas received from upstream pipeline interconnections with Antero Midstream and Crestwood Equity Partners LP. Mountaineer Midstream serves as a critical inlet to the Sherwood Processing Complex, a primary destination for liquids-rich natural gas in northern West Virginia and one of the largest natural gas processing facilities in the United States.

Ohio Gathering. Ohio Gathering comprises a natural gas gathering system and condensate stabilization facility located in the core of the Utica Shale in southeastern Ohio. The gathering system spans the condensate, liquids-rich and dry gas windows of the Utica Shale for multiple producers that are targeting production from the Utica and Point Pleasant shale formations across Belmont, Monroe, Guernsey, Harrison and Noble counties in southeastern Ohio. Ohio Gathering is operated by our partner, MPLX. Substantially all gathering services on the Ohio Gathering system are provided pursuant to long-term, fee-based gathering agreements. Ascent and Gulfport are Ohio Gathering's key customers and the AMIs from our customers for this system cover approximately 825,000 surface acres in the aggregate.

Condensate and liquids-rich natural gas production is gathered, compressed, dehydrated and delivered to the Cadiz and Seneca processing complexes, which offer approximately 1.3 Bcf/d of processing capacity and are owned by a joint venture between MPLX and The Energy and Minerals Group. Dry gas production is gathered, dehydrated, compressed, and delivered to third-party pipelines serving the northeast and midwest markets.

As of December 31, 2021, we owned approximately a 37.8% interest in Ohio Gathering, which includes our ownership in OGC and OCC. For additional information, see Note 6 - Equity Method Investments to the consolidated financial statements.

Rockies.

The following table provides operating information regarding our Rockies reportable segment as of December 31, 2021.

	Aggregate throughput capacity - liquids (Mbbl/d)	Aggregate throughput capacity - natural gas (MMcf/d)	Average daily MVCs through 2026 (MMcf/d) [1]	Remaining MVCs (Bcfe)[1]	Weighted-average remaining contract life (Years)[1][2]	Weighted-average remaining MVC life (Years)[1][2]
Rockies	255	94	22	40	5.8	2.3

(1) Contract terms related to MVCs are presented for liquids and natural gas on a combined basis.
(2) Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the Rockies reportable segment total approximately 1.3 million surface acres in the aggregate.

Our Rockies reportable segment is comprised of our Polar and Divide system, Bison Midstream, and Niobrara G&P system.

Polar and Divide system. The Polar and Divide system, collectively Polar Midstream and Epping, which is located primarily in Williams and Divide counties in northwestern North Dakota, owns, operates and is currently developing crude oil and produced water gathering systems and transmission pipelines serving multiple customers that are targeting crude oil production from the Bakken and Three Forks shale formations. The Polar and Divide system is underpinned by long-term, fee-based gathering agreements, which include acreage dedications and MVCs. Whiting, Zavanna, Crescent Point and Enerplus are the key customers of the Polar and Divide system.

Crude oil that is gathered by the Polar and Divide system is delivered to interconnects with (i) the Dakota Access Pipeline, (ii) the COLT Hub rail facility, (iii) Enbridge Inc’s North Dakota Pipeline System and (iv) Global Partners LP's Basin Transload rail terminal. Produced water is delivered to third-party disposal facilities.

Bison Midstream system. The Bison Midstream system is located in Mountrail and Burke counties in northwestern North Dakota. Bison Midstream gathers, compresses and treats associated natural gas that exists in the crude oil stream produced from the Bakken and Three Forks shale formations. Our gathering agreements for the Bison Midstream system include long-term, fee-based or percent-of-proceeds contracts. Volume throughput on the Bison Midstream system is underpinned by acreage dedications from its key customers. A large U.S. independent crude oil and natural gas company and Oasis Petroleum Inc. are the key customers of Bison Midstream.

Natural gas gathered on the Bison Midstream system is delivered to Aux Sable Midstream LLC's (“Aux Sable”) Palermo Conditioning Plant in Palermo, North Dakota and then delivered to downstream pipelines serving Aux Sable’s 2.1 Bcf/d natural gas processing plant in Channahon, Illinois.

Niobrara G&P system. The Niobrara G&P system is located near Hereford, Colorado, in rural Weld County, the largest crude oil and natural gas producing county in the state. Gathering and processing services on the Niobrara G&P system are provided pursuant to long-term, fee-based gathering agreements with producers that are primarily targeting crude oil production from the Niobrara and Codell shale formations. Civitas Resources, Inc. and a large U.S. independent crude oil and natural gas company are the key customers of the Niobrara G&P system and have underpinned our volume throughput with acreage dedications and MVCs.

The Niobrara G&P system operates a low-pressure associated natural gas gathering system, and a cryogenic natural gas processing plant with processing capacity of 60 MMcf/d. The Niobrara G&P system also processes liquids-rich natural gas that is produced by a customer in Laramie County, Wyoming and is delivered to the inlet of our processing plant by a third-party gathering system.

Residue gas is delivered to the Colorado Interstate Gas and Trailblazer Pipeline and processed NGLs are delivered to the Overland Pass Pipeline.

Permian.

The following table provides operating information regarding our Permian reportable segment as of December 31, 2021.

	Aggregate throughput capacity (MMcf/d)	Average daily MVCs through 2026 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) [1]	Weighted-average remaining MVC life (Years)
Summit Permian system	60	n/a	n/a	5.7	n/a
Double E	1,350	890	3,390	9.8	9.8

[1] Weighed based on contract AMI's.
[2] Presented on a gross basis. Existing MVC's contractually increase to 1.0 Bcf/d beginning in November 2024.

AMIs for the Permian reportable segment cover approximately 91,000 surface acres in the aggregate.

Our Permian reportable segment is comprised of our Summit Permian system and our equity method investment in Double E.

Summit Permian system. The Summit Permian system is an associated natural gas gathering and processing system operating in the northern Delaware Basin in Eddy and Lea counties in New Mexico. Gathering and processing services on the Summit Permian system are provided pursuant to long-term, fee-based gathering agreements with producers that are primarily targeting crude oil production from the Bone Spring and Wolfcamp shale formations. XTO is the key customer of the Summit Permian system.

The Summit Permian system operates a low-pressure natural gas gathering system and a 60 MMcf/d cryogenic processing plant. Residue natural gas is delivered to the Double E and Transwestern Pipeline and processed NGLs are delivered to the Lone Star NGL Pipeline.

Double E. Double E is a 135 mile, 1.35 Bcf/d, FERC-regulated interstate natural gas transmission pipeline that commenced operations in November 2021 and provides transportation service from receipt points in the Delaware Basin to various delivery points in and around the Waha hub in Texas. Double E is underpinned by 1.0 Bcf/d of long-term take-or-pay contracts with Exxon, Marathon Oil, Matador Resource and Summit Midstream Marketing. In 2021, we entered into negotiated rate agreements with an average term of 10 years from the in-service date of the pipeline, which occurred on November 18, 2021 and with total MDTQ's that increase from 585,000 Dth/d during the first year of the agreement to 1,000,000 Dth/d in the fourth year, which equates to approximately 74% of its certificated capacity of 1,350,000 Dth/d. Volume throughput is received from multiple processing plants, including Summit Permian's Lane plant, XTO's Cowboy plant, Lucid's Roadrunner plant, San Mateo's Black River plant and Sendero Midstream's Carlsbad plant. The Partnership owns 70% of Double E and operates the pipeline.

Piceance.

The following table provides operating information regarding our Piceance reportable segment as of December 31, 2021.

	Aggregate throughput capacity (MMcf/d)	Average daily MVCs through 2026 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years) [1]	Weighted-average remaining MVC life (Years)[1]
Piceance	1,151	244	446	12.4	4.4

[1] Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the Piceance reportable segment cover approximately 553,000 surface acres in the aggregate.

Our Piceance reportable segment is comprised of our Grand River gathering system.

Grand River is primarily located in Garfield County, one of the largest natural gas producing counties in Colorado. The Grand River system provides natural gas gathering services pursuant to primarily long-term and fee-based agreements with multiple producers, including its key customers, Caerus Oil and Gas and Terra Energy Partners. Volume throughput on the Grand River system is underpinned with acreage dedications and MVCs.

The Grand River system is primarily a low-pressure gathering system located in western Colorado that gathers natural gas produced from directional wells targeting the liquids-rich Mesaverde formation. The Grand River system also gathers natural gas produced from the Mancos and Niobrara shale formations.

Natural gas gathered and/or processed on the Grand River system is compressed, dehydrated, processed and/or discharged to downstream pipelines serving (i) the Meeker Processing Complex, (ii) the Williams Processing Complex and (iii) the TransColorado Pipeline system. Processed NGLs from Grand River are injected into the Mid-America Pipeline system or delivered to local markets. In addition, certain of our gathering agreements with our customers on the Grand River system permit us to retain, and monetize for our own account, condensate volumes that naturally discharge from the liquids-rich natural gas as it moves across our system.

Barnett.

The following table provides operating information regarding our Barnett reportable segment as of December 31, 2021.

	Throughput capacity (MMcf/d)	Average daily MVCs through 2026 (MMcf/d)	Remaining MVCs (Bcf)	Weighted-average remaining contract life (Years)[1]	Weighted-average remaining MVC life (Years)[1]
Barnett	450	n/a	n/a	5.9	n/a

[1] Weighted average based on total remaining MVC (total remaining MVCs multiplied by average rate).

AMIs for the Barnett reportable segment cover approximately 124,000 surface acres.

Our Barnett reportable segment is comprised of DFW Midstream system.

The DFW Midstream system is primarily located in southeastern Tarrant County, in north-central Texas. We consider this area to be the core of the core of the Barnett Shale because of the quality of the geology and the high production profile of the wells drilled to date in our service area. The DFW Midstream system is underpinned by a long-term, fee-based gathering agreements with Total Gas & Power North America, Inc. (“Total”) and other customers. Total is the key customer for DFW Midstream.

The DFW Midstream system includes natural gas gathering pipelines located under both private and public property and is partially located along existing electric transmission corridors. Compression on the system is powered by electricity. To offset the costs we incur to operate the system's electric-drive compressors, we either pass through a portion of the power expense to our customers or retain a fixed percentage of the natural gas that we gather.

The DFW Midstream system currently has six primary interconnections with third-party, primarily intrastate pipelines. These interconnections enable us to connect our customers, directly or indirectly, with the major natural gas market hubs in Texas and Louisiana.

Our Customers

The systems that we operate and/or have significant ownership interests in have a diverse group of customers and counterparties comprising affiliates and/or subsidiaries of some of the largest natural gas and crude oil producers in North America.

Regulation of the Natural Gas and Crude Oil Industries

General. Sales by producers of natural gas, crude oil, condensate and NGLs are currently made at market prices. However, gathering and transportation services are subject to various types of regulation, which may affect certain aspects of our business and the market for our services. FERC regulates the transportation of natural gas in interstate commerce and the interstate transportation of crude oil, petroleum products and NGLs. FERC regulation includes reviewing and accepting or approving rates and other terms and conditions for such transportation services and authorizing and regulating the construction and operation of interstate natural gas pipelines. FERC is also authorized to prevent and sanction market manipulation in natural gas markets while the FTC is authorized to prevent and sanction market manipulation in petroleum markets and the CFTC is authorized to prevent and sanction fraud and price manipulations in the commodity and futures markets, including the energy futures markets. State and municipal regulations may apply to the production and gathering of certain natural gas, the construction and operation of natural gas and crude oil facilities and the rates and practices of gathering systems and intrastate pipelines.

Regulation of Crude Oil and Natural Gas Exploration, Production and Sales. Sales of crude oil and NGLs are not currently regulated and are transacted at market prices. In 1989, the U.S. Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and non-price controls affecting wellhead sales of natural gas. FERC, which has the authority under the NGA to regulate the prices and other terms and conditions of the sale of natural gas for resale in interstate commerce, has issued blanket authorizations for all gas resellers subject to its regulation, except interstate pipelines, to resell natural gas at market prices. Either Congress or FERC (with respect to the resale of gas in interstate commerce), however, could re-impose price controls in the future.

Exploration and production operations are subject to various types of federal, state and local regulation, including, but not limited to, permitting, well location, methods of drilling, well operations and conservation of resources. While these regulations do not directly apply to our business, they may affect our customers' ability to produce natural gas.

Regulation of the Gathering and Transportation of Natural Gas and Crude Oil. We believe that the majority of our natural gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC. Our Double E Pipeline, which is an interstate natural gas pipeline located in New Mexico and Texas, and Epping Pipeline interstate crude oil pipeline, which is located in North Dakota and owned and operated by Epping, are subject to FERC’s jurisdiction and oversight pursuant to FERC's authority under the NGA and the ICA, respectively. Epping and Double E have tariffs on file with FERC.

In addition to approving and regulating the construction and operation of interstate natural gas pipelines, FERC also regulates such pipelines’ rates and terms and conditions of service, including transportation service agreements and negotiated rate agreements.

Under FERC’s ICA jurisdiction, rates for interstate movements of liquids by pipeline are currently regulated primarily through an annual indexing methodology, under which pipelines increase or decrease their existing rates in accordance with a FERC-specified adjustment that sets a rate ceiling. This adjustment, which may be positive or negative in a given year, is subject to review every five years. For the five-year period beginning on July 1, 2016, FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23%. In 2016, FERC proposed a policy change that would deny proposed index increases for pipelines under certain circumstances where revenues exceed cost-of-service by a certain percentage or where the proposed index increases exceed certain annual cost changes reported to FERC. FERC terminated this rulemaking on February 20, 2020 without adopting any part of the proposal. FERC completed its five-year review of its index adjustment by issuing an order on December 17, 2020 adopting a new annual index adjustment of the producer price index for finished goods plus 0.78% to become effective starting July 1, 2021. FERC’s order is subject to rehearing and possible judicial review.

Under current FERC regulations, liquids pipelines can request a rate increase that exceeds the rate obtained through the indexing methodology by using a cost-of-service approach, but a pipeline must establish that a substantial divergence exists between its actual costs and the rates resulting from the indexing methodology. The rates charged by Epping may also be affected by FERC’s March 15, 2018 announcement of a revised policy eliminating the recovery of an income tax allowance in cost-of-service-based rates by FERC-jurisdictional crude oil and natural gas pipelines owned by master limited partnerships. FERC has not required oil pipelines on an industry-wide basis to decrease their rates to implement the new policy, but FERC has stated that the effects of the revised policy statement must be incorporated in annual FERC financial reports made by oil pipelines. The effect of the elimination of the income tax allowance for MLP pipelines, as well as the reduction in the corporate income tax rate resulting from the Tax Cuts and Jobs Act of 2017 (the “Tax Reform Legislation”), was considered in FERC’s five-year review of index rate adjustments which resulted in the December 17, 2020 order adopting a new annual index adjustment for the five-year period starting July 1, 2021.

The ICA permits interested persons to challenge proposed new or changed rates and authorizes FERC to suspend the effectiveness of such rates for up to seven months and investigate such rates. If, upon completion of an investigation, FERC finds that the new or changed rate is unlawful, it is authorized to require the pipeline to refund revenues collected in excess of the just and reasonable rate during the term of the investigation. FERC may also investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Under certain circumstances, FERC could limit

Epping's ability to set rates based on costs or could order reduced rates and reparations to complaining shippers for up to two years prior to the date of a complaint. FERC also has the authority to change terms and conditions of service if it determines that they are unjust and unreasonable or unduly discriminatory or preferential. The ICA also imposes potential criminal liability for certain violations of the statute.

FERC has jurisdiction over, among other things, the construction, ownership and commercial operation of pipelines and related facilities used in the transportation and storage of natural gas in interstate commerce, including the modification, extension, enlargement, and abandonment of such facilities. FERC also has jurisdiction over the rates, charges, and term and conditions of service for the transportation and storage of natural gas in interstate commerce. With respect to transportation rates, FERC exercises its ratemaking authority by applying cost-of-service principles to limit the maximum and minimum levels of tariff-based recourse rates; however, it also allows for discounted or negotiated rates as an alternative to cost-based rates. In addition, FERC regulations also restrict interstate natural gas pipelines from sharing certain transportation or customer information with marketing affiliates and require that the transmission function personnel of interstate natural gas pipelines operate independently of the marketing function personnel of the pipeline or its affiliates.

Pursuant to the NGA, existing interstate natural gas transportation and storage rates and terms and conditions of service may be challenged by complaint and are subject to prospective change by FERC. Additionally, rate changes and changes to terms and conditions of service proposed by a regulated natural gas interstate pipeline may be protested and such changes can be delayed and may ultimately be rejected by FERC. FERC may also initiate reviews of an interstate pipeline's rates. Double E currently holds authority from the FERC to charge and collect (i) "recourse rates," which are the maximum cost-based rates an interstate natural gas pipeline may charge for its services under its tariff; (ii) "discount rates," which are rates offered by the natural gas pipeline to shippers at discounts vis-à-vis the recourse rates and that fall within the cost-based maximum and minimum rate levels set forth in the natural gas pipeline's tariff; and (iii) "negotiated rates," which are rates negotiated and agreed to by the pipeline and the shipper for the contract term that may fall within or outside of the cost-based maximum and minimum rate levels set forth in the tariff, and which are individually filed with the FERC for review and acceptance. On November 18, 2021, we entered into negotiated rate agreements with an average term of 10 years from the in-service date of the pipeline and with total MDTQ's that increase from 585,000 Dth/d during the first year of the agreement to 1,000,000 Dth/d in the fourth year, which equates to approximately 74% of its certificated capacity of 1,350,000 Dth/d. When capacity is available and offered for sale, the rates (which include reservation, commodity, surcharges, and fixed fuel and lost and unaccounted for charges) and the terms and conditions at which such capacity is sold are subject to regulatory approval and oversight. Any successful challenge by a regulator or shipper in any of these matters could have a material adverse effect on our business, financial condition and results of operations.

Intrastate pipelines, which may include some pipelines that perform gathering functions, may be subject to safety regulation by the DOT, although typically state regulatory authorities (operating under a federal certification) perform this function. State regulatory authorities also have jurisdiction over the rates and practices of intrastate pipelines and gathering systems, including requirements for ratable takes or non-discriminatory access to pipeline services. The basis for state regulation and the degree of regulatory oversight of gathering systems and intrastate pipelines varies from state to state. In Texas, we are regulated as a gas utility and have filed tariffs with the Railroad Commission of Texas to establish rates and terms of service for our DFW Midstream system assets. We have not been required to file tariffs in the other states in which we operate, although we are required to submit shape files and other information regarding the location and construction of underground gathering pipelines in North Dakota. The states in which we operate have adopted complaint-based regulation that allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve access issues and rate grievances, among other matters. State authorities in the states in which we operate generally have not initiated investigations of the rates or practices of gathering systems or intrastate pipelines in the absence of a complaint. State regulation of intrastate pipelines continues to evolve and may become more stringent in the future. For example, in 2016, the North Dakota Industrial Commission ("NDIC") adopted rule changes that resulted in additional construction and monitoring requirements for all pipelines, including, but not limited to, those that transport produced water. The NDIC has also adopted reclamation bonding requirements for certain underground gathering pipelines in North Dakota.

Natural gas, crude oil and produced water production, gathering and transportation, including the construction of new gathering facilities and expansion of existing gathering facilities may also be subject to local regulation, such as approval and permit requirements.

Statutory Compliance and Anti-Market Manipulation Rules. We are subject to the anti-market manipulation and penalty provisions in the NGA and the NGPA, as amended by the Energy Policy Act of 2005, which authorize FERC to impose fines of up to $1,388,496 per day per violation of the NGA, the NGPA, or their implementing rules, regulations, and orders subject to future adjustments for inflation. In addition, the FTC holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in petroleum markets, including the authority to request that a court impose fines of up to $1,323,791 per violation, subject to future adjustment for inflation. These agencies have promulgated broad rules and regulations prohibiting fraud and manipulation in oil and gas markets. The CFTC is directed under the CEA to prevent price manipulations in the commodity and futures markets, including the energy futures markets. Pursuant to statutory authority, the CFTC has adopted anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity and futures markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,303,559 per day per violation, subject to future adjustment for inflation, or triple the monetary gain to the violator for violations of the anti-market manipulation sections of the CEA. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation.

Safety and Maintenance. We are subject to regulation by the DOT, which establishes federal safety standards for the design, construction, operation and maintenance of natural gas and crude oil pipeline facilities. In the Pipeline Safety Act of 1992, Congress expanded the DOT's regulatory authority to include regulated gathering lines that had previously been exempt from federal jurisdiction. Additional legislation has been passed over the years to reauthorize federal funding for federal pipeline programs, increase penalties for safety violations and establish additional safety requirements. For example, in December 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 became law, reauthorizing PHMSA for funding through 2023 and requiring, among other things, rulemaking to amend the integrity management program, emergency response plan, operation and maintenance manual, and pressure control recordkeeping requirements for gas distribution operators; to create new leak detection and repair program obligations; and to set new minimum federal safety standards for onshore gas gathering lines.

The DOT has delegated the implementation of pipeline safety requirements to PHMSA, which has adopted and enforces safety standards and procedures applicable to a limited number of our pipelines. In addition, many states, including the states in which we operate, have adopted regulations that are identical to or more restrictive than existing PHMSA regulations for intrastate pipelines. Among the regulations applicable to us, PHMSA requires pipeline operators to develop integrity management programs for certain pipelines located in high consequence areas, which include high-population areas such as the Dallas-Fort Worth greater metropolitan area where our DFW Midstream system is located. While the majority of our pipelines have historically met the DOT definition of gathering lines and were thus exempt from the integrity management requirements of PHMSA, we also operate a limited number of pipelines that are subject to the integrity management requirements. Those regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

In addition, PHMSA has taken recent action to regulate gathering systems, which includes integrity management requirements. In November 2021, PHMSA issued a final rule that extended pipeline safety requirements to onshore gas gathering pipelines. The rule requires all onshore gas gathering pipeline operators to comply with PHMSA's incident and annual reporting requirements. It also extends existing pipeline safety requirements to a new category of gas gathering pipelines, "Type C" lines, which generally include high-pressure pipelines that are larger than 8.625 inches in diameter. Safety requirements applicable to Type C lines vary based on pipeline diameter and potential failure consequences. The final rule becomes effective in May 2022 and operators must comply with the applicable safety requirements by November 2022.

PHMSA has also imposed additional requirements on onshore gas transmission systems and hazardous liquids pipelines in recent years. In October 2019, the PHMSA issued three new final rules. One rule, which became effective in December 2019, establishes procedures to implement the expanded emergency order enforcement authority set forth in an October 2016 interim final rule. Among other things, this rule allows the PHMSA to issue an emergency order without advance notice or opportunity for a hearing. The other two rules, which became effective in July 2020, imposed several new requirements on operators of onshore gas transmission systems and hazardous liquids pipelines. The rule concerning gas transmission extends the requirement to conduct integrity assessments beyond “high consequence areas” (“HCAs”) to pipelines in “moderate consequence areas” (“MCAs”). It also includes requirements to reconfirm Maximum Allowable Operating Pressure (“MAOP”), report MAOP exceedances, consider seismicity as a risk factor in integrity management, and use certain safety features on in-line inspection equipment. PHMSA modified the rule in July 2020, in response to a petition for reconsideration, to limit the rule’s recordkeeping requirement related to class location changes to gas transmission pipelines (not gas distribution pipelines) and to clarify that the rule’s reconfirmation requirements related to MAOP is limited to segments without traceable, verifiable and complete pressure test records. The rule concerning hazardous liquids extends the required use of leak detection systems beyond HCAs to all regulated non-gathering hazardous liquid pipelines, requires reporting for gravity fed lines and unregulated gathering lines, requires periodic inspection of all lines not in HCAs, calls for inspections of lines after extreme weather events, and adds a requirement to make all lines in or affecting HCAs capable of accommodating in-line inspection tools over the next 20 years.

Gathering systems like ours are also subject to a number of other federal and state laws and regulations, including the Federal Occupational Safety and Health Act and comparable state statutes, the purposes of which are to protect the health and safety of workers, both generally and within the pipeline industry. In addition, the Occupational Safety and Health Administration hazard communication standard, EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that such information be provided to employees, state and local government authorities and the public.

Environmental Matters

General. Our operation of pipelines and other assets for the gathering, treating, transportation and/or processing of natural gas and the gathering of crude oil and produced water is subject to stringent and complex federal, state and local laws and regulations relating to the protection of the environment. As an owner or operator of these assets, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way we operate;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas inhabited by endangered or threatened species;
- delaying system modification or upgrades during permit reviews;
- requiring investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and
- enjoining the operations of facilities deemed to be in non-compliance with permits or permit requirements issued pursuant to or imposed by such environmental laws and regulations.

Failure to comply with these laws and regulations may trigger administrative, civil and criminal enforcement measures, including the assessment of monetary penalties. Certain environmental statutes impose strict joint and several liability for costs required to clean up and restore sites where substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more stringent requirements, resulting in more restrictions and limitations, on activities that may affect the environment. Thus, there can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and actual future expenditures may be different from the amounts we currently anticipate. We try to anticipate future regulatory requirements that might be imposed and plan accordingly to remain in compliance with changing environmental laws and regulations and to minimize the costs of such compliance. We also actively participate in industry groups that help formulate recommendations for addressing existing and future regulations.

The following is a discussion of the material environmental laws and regulations that relate to our business.

Hazardous Substances and Waste. Our operations are subject to environmental laws and regulations relating to the management and release of solid and hazardous wastes and other substances, including hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. Furthermore, the Toxic Substances Control Act and analogous state laws, impose requirements on the use, storage and disposal of various chemicals and chemical substances at our facilities. CERCLA and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. We may handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

We also generate industrial wastes that are subject to the requirements of the RCRA and comparable state statutes. While the RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Although we generate minimal hazardous waste, it is possible that non-hazardous wastes, which could include wastes currently generated during our operations, will in the future be designated as hazardous wastes and, therefore, be subject to more rigorous and costly disposal requirements. Moreover, from time to time, the EPA and state regulatory agencies have considered the adoption of stricter disposal standards for non-hazardous wastes, including natural gas wastes.

We currently own or lease properties where hydrocarbons are being or have been handled for many years. Although we believe that the previous operators utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been transported for treatment or disposal, without our knowledge. These properties and the wastes disposed thereon may be subject to CERCLA, the RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) or to perform remedial operations to prevent future contamination. We are not currently aware of any facts, events or conditions relating to such requirements that could materially impact our operations or financial condition.

Air Emissions. Our operations are subject to the federal CAA and comparable state and local laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including our facilities, and also impose various monitoring, control and reporting requirements. Such laws and regulations may require that we obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations and utilize specific emission control technologies to limit emissions. Our failure to comply with these requirements could subject us to monetary penalties, injunctions, conditions or restrictions on operations and criminal enforcement actions. Furthermore, we may be required to incur certain capital expenditures in the future to obtain and maintain operating permits and approvals for air pollutant emitting sources.

In October 2015, the EPA issued a new lower NAAQS for ozone. The previous ozone standard was set at 75 parts per billion (“ppb”). The revised standard has been lowered to 70 ppb. The lowered ozone NAAQS could subject us to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements and increased permitting delays and costs. The EPA reviewed the 2015 standard in 2020, but retained the standard without revision. Impacts from the 2015 standard vary by geographic location, but could include additional fees and more stringent permitting requirements, among other things. We will continue to monitor developments to determine if any adverse effects on our operations can be expected.

On June 3, 2016, the EPA finalized revisions to its 2012 New Source Performance Standard (“NSPS”) OOOO for the oil and gas industry, to reduce emissions of greenhouse gases - most notably methane - along with smog-forming VOCs. The revisions, which are published in the Federal Register under Subpart OOOOa, included the addition of methane to the pollutants covered by the rule, along with requirements for detecting and repairing leaks at gathering and boosting stations. The revised rule applies to sources that have been modified, constructed, or reconstructed after September 18, 2015. Further, in November 2021, the EPA issued a new proposed rule targeting methane emissions from new and existing oil and gas sources. The proposed rule would: (1) update NSPS OOOOa; (2) adopt a new NSPS OOOOb for sources that commence construction, modification or reconstruction after the date the proposed rule is published in the Federal Register; and (3) adopt a new NSPS OOOOc to establish emissions guidelines, which will inform state plans to establish standards for existing sources. If finalized, these increasingly stringent requirements, or the application of new requirements to existing facilities, could result in additional restrictions on operations and increased compliance costs for us or our customers.

On November 16, 2016 the Bureau of Land Management (“BLM”) issued a final rule to reduce venting and flaring of natural gas on public and Indian lands. The final rule mirrors many of the requirements found in NSPS OOOOa, with additional natural gas royalty requirements for flared volumes at sites already connected to gas capture infrastructure. In September 2018, the BLM published a final rule that rescinded several requirements of this rule. However, in July 2020, the U.S. District Court for the Northern District of California vacated BLM’s 2018 revision rule. In addition, in October 2020, a Wyoming federal district judge vacated the 2016 venting and flaring rule. Environmental groups appealed the October 2020 decision in December 2020 and litigation is ongoing. While the rule, if implemented, is expected to have little or no direct impact on our operations, our customers that are primarily upstream wellhead operators may be impacted by the requirements in this rule.

In recent years, the EPA has also demonstrated an increased focus on CAA compliance for natural gas gathering operations. For example, in September 2019, EPA issued an enforcement alert noting that EPA identified CAA noncompliance caused by unauthorized and/or excess emissions from depressurizing pig launchers and receivers in natural gas gathering operations. The alert discussed engineering, design, operations, and maintenance practices that EPA found that can cause noncompliance and summarizes engineering solutions to reduce emissions. This increased focus on natural gas gathering operations and any resulting enforcement actions by the EPA or state agencies could subject us to monetary penalties, injunctions, conditions or restrictions on operations.

Water Discharges. The CWA and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into regulated waters, which impacts our ability to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of pollutants and chemicals. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. These permits require us to control storm water runoff from some of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. Except as otherwise disclosed in this annual report, we believe that we are in substantial compliance with all applicable requirements of the CWA and analogous state laws and regulations relating to water discharges.

Oil Pollution Control Act. The OPA requires the preparation of an SPCC plan for facilities engaged in drilling, producing, gathering, storing, processing, refining, transferring, distributing, using, or consuming oil and oil products, and which due to their location, could reasonably be expected to discharge oil in harmful quantities into or upon the navigable waters of the United States. The owner or operator of an SPCC-regulated facility is required to prepare a written, site-specific spill prevention plan, which details how a facility's operations comply with the requirements. To be in compliance, the facility's SPCC plan must satisfy all of the applicable requirements for drainage, bulk storage tanks, tank car and truck loading and unloading, transfer operations (intrafacility piping), inspections and records, security and training. Certain of our facilities are classified as SPCC-regulated facilities. We believe that they are in substantial compliance with all applicable requirements of OPA.

Hydraulic Fracturing. Hydraulic fracturing is an important practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily regulated by state agencies. A number of states – such as Colorado, as discussed above – have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure and well construction requirements on crude oil and/or natural gas drilling activities. For example, during the 2021-2022 election cycle, Colorado representatives proposed a ballot initiative to ban hydraulic fracturing on all non-federal land, but the proposed initiative has yet to garner significant support. States also could elect to prohibit hydraulic fracturing altogether, as New York, Maryland, and Vermont have done. In addition, certain local governments have adopted, and additional local governments may adopt, ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. These initiatives and similar efforts in Colorado and elsewhere could restrict oil and gas development in the future.

The EPA has also moved forward with various regulatory actions, including a proposal to issue new regulations under the New Source Performance Standards (NSPS) to expand and strengthen emissions reduction requirements under NSPS OOOOa for new, modified and reconstructed oil and natural gas sources, and require states to reduce methane emissions from existing sources nationwide. For further discussion of NSPS OOOOa and subsequent actions by the EPA, see the "—Air Emissions" section above. The BLM has also asserted regulatory authority over aspects of the hydraulic fracturing process, and issued a final rule in March 2015 that established more stringent standards for performing hydraulic fracturing on federal and Indian lands, including requirements relating to well construction and integrity, handling of wastewater and chemical disclosure. However, in December 2017, the BLM published a final rule rescinding the 2015 rule. The U.S. District Court for the Northern District of California upheld the December 2017 rescission rule in a March 2020 decision, and the State of California and environmental plaintiffs appealed. Litigation is currently ongoing.

Further, several federal governmental agencies have conducted reviews and studies on the environmental aspects of hydraulic fracturing, including the EPA. The results of such reviews or studies could spur initiatives to further regulate hydraulic fracturing.

State and federal regulatory agencies recently have also focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. Some state regulatory agencies, including those in Colorado, Ohio, and Texas, have modified their regulations or guidance to account for induced seismicity. These developments could result in additional regulation and restrictions on the use of injection disposal wells and hydraulic fracturing. Such regulations and restrictions could cause delays and impose additional costs and restrictions on our customers.

Additionally, certain of our customers produce oil and gas on federal lands. On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. Several states filed lawsuits challenging the suspension, and on June 15, 2021, a judge in the U.S. District Court for the Western District of Louisiana issued a nationwide temporary injunction blocking the suspension. The Department of the Interior appealed the U.S. District Court’s ruling, but resumed oil and gas leasing pending resolution of the appeal. In November 2021, the Department of the Interior completed its review and issued a report on the federal oil and gas leasing program. The Department of the Interior’s report recommends several changes to federal leasing practices, including changes to royalty payments, bidding, and bonding requirements.

If new or more stringent federal, state or local legal restrictions relating to drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil that our customers produce, and could thereby adversely affect our revenues and results of operations. Compliance with such rules could also generally result in additional costs, including increased capital expenditures and operating costs, for our customers, which could ultimately decrease end-user demand for our services and could have a material adverse effect on our business.

Endangered Species Act. The Endangered Species Act restricts activities that may affect endangered or threatened species or their habitats. Some of our pipelines may be located in areas that are designated as habitats for endangered or threatened species.

National Environmental Policy Act. The NEPA establishes a national environmental policy and goals for the protection, maintenance and enhancement of the environment and provides a process for implementing these goals within federal agencies. Major projects having the potential to significantly impact the environment require review under NEPA. Many of our activities are covered under categorical exclusions which results in an expedited NEPA review process. Large upstream and downstream projects with significant cumulative impacts may be subject to longer NEPA review processes, which could impact the timing of those projects and our services associated with them.

Climate Change. The EPA has adopted regulations under the CAA that, among other things, establish GHG emission limits from motor vehicles as well as establish PSD construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis.

EPA rules also require the reporting of GHG emissions from specified large GHG-emitting sources in the United States, including onshore and offshore oil and natural gas systems. We are required to report under these rules for our assets that have GHG emissions above the reporting thresholds. In October 2015, the EPA issued revisions to Subpart W of the GHG reporting rule to include reporting requirements for gathering and booster stations, onshore natural gas transmission pipelines, and completions and workovers of oil wells with hydraulic fracturing. This development resulted in increased monitoring and reporting for our operations and for upstream producers for whom we provide midstream services.

In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. In general, the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). Although most of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that certain components of our operations, such as our gas-fired compressors, could become subject to state-level GHG-related regulation.

Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global GHG emissions. The agreement entered into force in November 2016 after over 70 countries, including the United States, ratified or otherwise consented to be bound by the agreement. In November 2019, the United States submitted formal notification to the United Nations that it intended to withdraw from the agreement. However, on January 20, 2021, President Biden signed an “Acceptance on Behalf of the United States of America” that reversed the prior withdrawal, and the United States officially rejoined the Paris Agreement on February 19, 2021. As part of rejoining the Paris Agreement, President Biden announced that the United States would commit to a 50 to 52 percent reduction from 2005 levels of GHG emissions by 2030 and set the goal of reaching net-zero GHG emissions by 2050. In addition, shortly after taking office in January 2021, President Biden issued a series of executive orders designed to address climate change. For example, the Executive Order on “Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis” sought to adopt new regulations and policies to address climate change and suspend, revise, or rescind, prior agency actions that were identified as conflicting with the Biden

Administration's climate policies. New legislation to regulate GHG emissions has also been periodically introduced in the United States Congress, but none have passed. Reentry into the Paris Agreement, new legislation, or President Biden's executive orders may result in the development of additional regulations or changes to existing regulations, which could have a material adverse effect on our business and that of our customers.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG-emitting energy sources, our products would become more desirable in the market with more stringent limitations on GHG emissions. Conversely, to the extent that our products are competing with lower GHG-emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions.

Other Information

Human Capital Resources. We recognize that our continued ability to attract, retain and motivate exceptional employees is vital to ensuring our long-term competitive advantage and the ability to create value for our unitholders. Our employees are critical to our long-term success and are essential to helping us meet our goals. Among other things, we support and incentivize our employees in the following ways:

- Talent development, compensation and retention – We strive to provide our employees with a rewarding work environment, including the opportunity for success and a platform for personal and professional development. We provide a competitive benefits package designed to attract and retain a skilled and diverse workforce. We offer our employees a comprehensive benefits package, which includes company funded health plan options, vision and dental coverage, healthcare savings account, paid time off, parental leave and flexible spending accounts. We also provide professional training and development opportunities as well as education reimbursement. We also offer employees immediate eligibility in our 401(k) plan with company matching program.
- Health and safety – Employee health and safety in the workplace is one of our core values. Some of the ways in which we support the health and safety of our employees include wellness programs with incentives and employee assistance programs.
- Inclusion and diversity – We are committed to efforts to increase diversity and foster an inclusive work environment that supports our workforce.

As of December 31, 2021, the Partnership employed 209 people who provide direct, full-time support to our operations. None of our employees are covered by collective bargaining agreements, and we have never experienced any business interruption as a result of any labor disputes.

Availability of Reports. We make certain filings with the SEC, including, among other filings, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments and exhibits to those reports, available free of charge through our website, www.summitmidstream.com, as soon as reasonably practicable after the date they are filed with, or furnished to, the SEC. We also post announcements, updates, events, investor information and presentations on our website in addition to copies of all recent news releases. We may use the Investors section of our website to communicate with investors. It is possible that the financial and other information posted there could be deemed to be material information. Documents and information on our website are not incorporated by reference herein. The SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC through the SEC's website, http://www.sec.gov.

Item 1A. Risk Factors.

You should carefully consider the following risk factors in addition to the other information included in this Annual Report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common units:

Risks Related to COVID-19

The COVID-19 pandemic has had, and is expected to continue to have, an adverse impact on our business, results of operations, financial position and cash flows.

The outbreak of COVID-19 and its variants continues to be a rapidly evolving situation. The pandemic has resulted in widespread adverse impacts on the global economy and on our business, including our customers, employees, supply chain, and distribution network. We are currently unable to predict the ultimate impact that it may have on our business, future results of operations, financial position or cash flows. The extent to which our operations continue to be impacted by the COVID-19 pandemic will depend largely on future developments, which remain highly uncertain and cannot be accurately predicted. While many of the restrictions and measures initially implemented during 2020 have since been softened or lifted in varying degrees in different locations around the world, and the manufacture and distribution of COVID-19 vaccines during 2021 helped to initiate a recovery from the pandemic, the uncertainty regarding new potential variants of COVID-19 and the success of any vaccines in respect thereof, may in the future cause a reduction in global economic activity or prompt, the re-imposition of certain restrictions and measures. In addition, even if not required by governmental authorities, increases in COVID-19 cases, such as if a new variant emerges, may result in significantly reduced economic activity, particularly in affected areas, which could result in a sharp reduction in the demand for oil and a decline in oil prices as occurred during 2020.

In response to the COVID-19 pandemic, we have modified our business practices, including restricting employee travel, utilizing COVID-19 pandemic tax relief (as allowed by the Consolidated Appropriations Act, 2021, the “ERC Tax Credit”), modifying employee work locations, implementing social distancing and enhancing sanitary measures in our facilities. Many of our suppliers, vendors and service providers have made similar modifications. We may take further actions as government authorities require or recommend or as we determine to be in the best interests of our employees, customers, partners and suppliers. There is no certainty that such measures will be sufficient to mitigate the risks posed by the virus and its variants, in which case our employees may become sick, our ability to perform critical functions could be impaired, and we may be unable to respond to the needs of our business. The resumption of normal business operations after such interruptions may be delayed or constrained by lingering effects of COVID-19 on our suppliers, third-party service providers, and/or customers.

As a result of the COVID-19 pandemic, we have experienced difficulty in recruiting and hiring skilled labor throughout our organization.

Concerns over the prolonged negative effects of the COVID-19 outbreak on economic and business prospects across the world, including as a result of new variants of the virus, have also contributed to oil price volatility and uncertainty regarding the outlook for the global economy. At this point, we cannot accurately predict the long-term effects current market conditions due to the COVID-19 pandemic will have on our business, which will depend on, among other factors, the duration of the continued outbreak, the effects of new virus variants, the extent of increased infection rates in response to economic re-openings, the efficacy of vaccines and the extent and overall economic effects of the continuing governmental response to the pandemic, including any lockdowns, other restrictions or a general slowdown of the reopening process in the affected areas.

The impact of COVID-19 may also exacerbate other risks discussed below, any of which could have a material effect on us. This situation is changing rapidly, and additional impacts may arise that we are not aware of currently.

Risks Related to Our Operations

We may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, to enable us to pay distributions to holders of our common units.

We may not have sufficient available cash from operating surplus each quarter to pay the distributions to holders of our common units. We have not made a distribution on our common units or Series A Preferred Units since we announced suspension of those distributions on May 3, 2020. Further, we may not pay distributions on the common units or Series A Preferred Units in the foreseeable future, and there are restrictions on our ability to pay distributions under our outstanding indebtedness that restrict our ability to pay cash distributions on any of our equity securities. The amount of cash we can distribute on our units principally depends upon the amount of cash we generate from our operations, which will fluctuate from quarter to quarter based on, among other things:

- the volumes we gather, transport, treat and process;
- the level of production of natural gas and crude oil (and associated volumes of produced water) from wells connected to our gathering systems, which is dependent in part on the demand for, and the market prices of, crude oil, natural gas and NGLs;
- damage to pipelines, facilities, related equipment and surrounding properties caused by earthquakes, floods, fires, severe weather, explosions and other natural disasters, accidents and acts of terrorism;
- leaks or accidental releases of hazardous materials into the environment;
- weather conditions and seasonal trends;
- changes in the fees we charge for our services;
- changes in contractual MVCs and our customer’s capacity to make MVC shortfall payments when due;
- the level of competition from other midstream energy companies in our areas of operation;
- changes in the level of our operating, maintenance and general and administrative expenses;
- regulatory action affecting the supply of, or demand for, crude oil, natural gas and NGLs, the fees we can charge, how we contract for services, our existing contracts, our operating and maintenance costs or our operating flexibility; and
- prevailing economic and market conditions.

In addition, the actual amount of cash we have available for distribution to our common unitholders depends on other factors, some of which are beyond our control, including:

- the level and timing of capital expenditures we make;
- the level of our operating, maintenance and general and administrative expenses, including reimbursements of expenses incurred on our behalf by our General Partner;
- the cost of acquisitions, if any;
- our ability to sell assets, if any, and the price that we may receive for such assets;
- our debt service requirements and other liabilities;
- fluctuations in our working capital needs;
- our ability to borrow funds and access the debt and equity capital markets;
- restrictions contained in our debt agreements;
- the amount of cash reserves established by our General Partner;
- not receiving anticipated shortfall payments from our customers;
- adverse legal judgments, fines and settlements;
- distributions paid on our Series A Preferred Units, if any, or on the preferred stock of our subsidiaries; and
- other business risks affecting our cash levels.

We depend on a relatively small number of customers for a significant portion of our revenues. For example, Caerus, a customer on our Piceance segment accounts for over 10% of our aggregated revenue. The loss of, or material nonpayment or nonperformance by, or the curtailment of production by, any one or more of our customers could materially adversely affect our revenues, cash flows and ability to make cash distributions to our unitholders.

Certain of our customers may have material financial and liquidity issues or may, as a result of operational incidents or other events, be disproportionately affected as compared to larger, better-capitalized companies. Any material nonpayment or nonperformance by any of our customers could have a material adverse effect on our revenues and cash flows and our ability to make cash distributions to our unitholders. We expect our exposure to concentrated risk of nonpayment or nonperformance to continue as long as we remain substantially dependent on a relatively small number of customers for a significant portion of our revenues.

If any of our customers curtail or reduce production in our areas of operation, it could reduce throughput on our systems and, therefore, materially adversely affect our revenues, cash flows and ability to make cash distributions to our unitholders.

Further, we are subject to the risk of non-payment or non-performance by our larger customers. We cannot predict the extent to which our customers' businesses would be impacted if conditions in the energy industry deteriorate, nor can we estimate the impact such conditions would have on any of our customers' abilities to execute their drilling and development programs or perform under our gathering and processing agreements. An extended low commodity price environment negatively impacts natural gas producers causing some producers in the industry significant economic stress, including, in certain cases, to file for bankruptcy protection or to renegotiate contracts. To the extent that any customer is in financial distress or commences bankruptcy proceedings, contracts with these customers may be subject to renegotiation or rejection under applicable provisions of the United States Bankruptcy Code. Any material non-payment or non-performance by our customers could adversely affect our business and operating results.

We are exposed to the creditworthiness and performance of our customers, suppliers and contract counterparties and any material nonpayment or nonperformance by one or more of these parties could materially adversely affect our financial and operating results.

Although we attempt to assess the creditworthiness and associated liquidity of our customers, suppliers and contract counterparties, there can be no assurance that our assessments will be accurate or that there will not be a rapid or unanticipated deterioration in their creditworthiness, which may have an adverse impact on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. In addition, there can be no assurance that our contract counterparties will perform or adhere to existing or future contractual arrangements, including making any required shortfall payments or other payments due under their respective contracts.

The policies and procedures we use to manage our exposure to credit risk, such as credit analysis, credit monitoring and, if necessary, requiring credit support, cannot fully eliminate counterparty credit risks. To the extent our policies and procedures prove to be inadequate, our financial and operational results may be negatively impacted.

Some of our counterparties may be highly leveraged, have limited financial resources and/or have recently experienced a rating agency downgrade and will be subject to their own operating and regulatory risks. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with such parties. In addition, volatility in commodity prices could have a negative impact on our counterparties, which, in turn, could have a negative impact on their ability to meet their obligations to us.

Any material nonpayment or nonperformance by any of our counterparties or suppliers could require us to pursue substitute counterparties or suppliers for the affected operations or reduce our operations. There can be no assurance that any such efforts would be successful or would provide similar financial and operational results.

Adverse developments in our areas of operation could materially adversely impact our financial condition, results of operations, cash flows and ability to make cash distributions to our unitholders.

Our operations are focused on gathering, treating, transporting and processing services in the following unconventional resource basins, primarily shale formations: the Utica Shale, the Williston Basin, the DJ Basin, the Permian Basin, the Piceance Basin, the Barnett Shale and the Marcellus Shale. Due to our limited industry diversity, adverse developments in the natural gas and crude oil industries or in our existing areas of operation could have a significantly greater impact on our financial condition, results of operations and cash flows than if we did not have such limited diversity.

Significant prolonged weakness in natural gas, NGL and crude oil prices could reduce throughput on our systems and materially adversely affect our revenues and cash available to make cash distributions to our unitholders.

Lower natural gas, NGL and crude oil prices could negatively impact exploration, development and production of natural gas and crude oil, thereby resulting in reduced throughput on our gathering systems. Additionally, certain of our customers in each of our areas of operations have reduced, and others could reduce, drilling activity and capital expenditure budgets. If natural gas, NGL and/or crude oil prices decrease, it could cause sustained reductions in exploration or production activity in our areas of operation and result in a further reduction in throughput on our systems, which could have a material adverse effect on our business, financial condition, results of operations and ability to make cash distributions to our unitholders.

Because of the natural decline in production from our customers' existing wells, our success depends in part on our customers replacing declining production and also on our ability to maintain levels of throughput on our systems. Any decrease in the volumes that we gather and process could materially adversely affect our business and operating results.

The customer volumes that support our business depend on the level of production from natural gas and crude oil wells connected to our systems, the production from which may be less than expected and will naturally decline over time. As a result, our cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on our systems, we must obtain new sources of volume throughput. The primary factors affecting our ability to obtain new sources of volume throughput include (i) the level of successful drilling activity in our areas of operation and (ii) our ability to compete for new volumes on our systems.

We have no control over the level of drilling activity in our areas of operation, the amount of reserves associated with wells connected to our systems or the rate at which production from a well declines. In addition, we have no control over producers or their drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected hydrocarbon commodity prices;
- demand for crude oil, natural gas and other hydrocarbon products, including NGLs;
- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new crude oil and natural gas reserves. Drilling and production activities generally decrease as commodity prices decrease. In general terms, the prices of crude oil, natural gas and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- worldwide economic and geopolitical conditions;
- global or national health concerns, including the outbreak of pandemic or contagious disease, such as COVID-19, which may reduce demand for crude oil, natural gas and NGLs because of reduced global or national economic activity;
- Because of these factors, even if new crude oil or natural gas reserves are known to exist in areas served by our assets, producers may choose not to develop those reserves. If reductions in drilling activity result in our inability to maintain the current levels of throughput on our systems, those reductions could reduce our revenues and cash flows and materially adversely affect our ability to make cash distributions to our unitholders.
- weather conditions and seasonal trends;
- the levels of domestic production and consumer demand;
- the availability of imported liquefied natural gas (“LNG”);
- the ability to export LNG;
- the availability of transportation and storage systems with adequate capacity;
- the volatility and uncertainty of regional pricing differentials and premiums;
- the price and availability of alternative fuels, including alternative fuels that benefit from government subsidies;
- the effect of energy conservation measures;
- the nature and extent of governmental regulation and taxation; and
- the anticipated future prices of crude oil, natural gas and other hydrocarbon products, including NGLs.

In addition, it may be more difficult to maintain or increase the current volumes on our gathering systems, as several of the formations in the unconventional resource plays in which we operate generally have higher initial production rates and steeper production decline curves than wells in more conventional basins and may have steeper production decline curves than initially anticipated. Should we determine that the economics of our gathering, treating, transportation and processing assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, revenues associated with these assets will decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require us to incur higher maintenance capital expenditures over time, which will reduce our cash available for distribution.

Many of our costs are fixed and do not vary with our throughput. These costs will not decline ratably or at all should we experience a reduction in throughput, which could result in a decline in our revenues and cash flows and materially adversely affect our ability to make cash distributions to our unitholders.

Any significant decrease in the demand for natural gas and crude oil could reduce the volumes of natural gas and crude oil that we gather and process, which could adversely affect our business and operating results.

The volumes of natural gas and crude oil that we gather and process depend on the supply and demand for natural gas and crude oil and other hydrocarbon products in the areas served by our assets. Natural gas and crude oil compete with other forms of energy available to users, including electricity, coal, other fuels and alternative energy sources. Increased demand for such forms of energy at the expense of natural gas and crude oil could lead to a reduction in demand for our services. Any such reduction could result in a decline in our revenues and cash flows and materially adversely affect our ability to make cash distributions to our unitholders.

If our customers do not increase the volumes they provide to our gathering systems, our ability to make cash distributions to our unitholders may be materially adversely affected.

If we are unsuccessful in attracting new customers and/or new gathering opportunities with existing customers, our ability to make cash distributions to our unitholders will be impaired. Our customers are not obligated to provide additional volumes to our gathering systems, and they may determine in the future that drilling activities in areas outside of our current areas of operation are strategically more attractive to them. Reductions by our customers in our areas of mutual interest could result in reductions in throughput on our systems and materially adversely impact our ability to make cash distributions to our unitholders.

Certain of our gathering and processing agreements contain provisions that can reduce the cash flow stability that the agreements were designed to achieve.

We designed those gathering and processing agreements that contain MVC provisions to generate stable cash flows for us over the life of the MVC contract term while also minimizing our direct commodity price risk. Under certain of these MVCs, our customers agree to ship a minimum volume on our gathering systems or send a minimum volume to our processing plants or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. In addition, our gathering and processing agreements may also include an aggregate MVC, which represents the total amount that the customer must flow on our gathering system or send to our processing plants (or an equivalent monetary amount) over the MVC term. If such customer’s actual throughput volumes are less than its MVC for the contracted measurement period, it must make a shortfall payment to us at the end of the applicable measurement period. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped or processed for the applicable period and the MVC for the applicable period, multiplied by the applicable fee. To the extent that a customer’s actual throughput volumes are above or below its MVC for the applicable contracted measurement period, certain of our gathering agreements contain provisions that allow the customer to use the excess volumes or the shortfall payment to credit against future excess volumes or future shortfall payments, which could have a material adverse effect on our results of operations, financial condition and cash flows and our ability to make cash distributions to our unitholders.

We have not obtained independent evaluations of all of the reserves connected to our gathering systems; therefore, in the future, customer volumes on our systems could be less than we anticipate.

We do not routinely obtain or update independent evaluations of the reserves connected to our systems. Moreover, even if we did obtain independent evaluations of all of the reserves connected to our systems, such evaluations may prove to be incorrect. Crude oil and natural gas reserve engineering requires subjective estimates of underground accumulations of crude oil and natural gas and assumptions concerning future crude oil and natural gas prices, future production levels and operating and development costs.

Accordingly, we may not have accurate estimates of total reserves dedicated to our systems or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to our gathering systems are less than we anticipate and we are unable to secure additional volumes, it could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

Our industry is highly competitive, and increased competitive pressure could materially adversely affect our business and operating results.

We compete with other midstream companies in our areas of operations, some of which are large companies that have greater financial, managerial and other resources than we do. In addition, some of our competitors may have assets in closer proximity to natural gas and crude oil supplies and may have available idle capacity in existing assets that would not require new capital investments for use. Our competitors may expand or construct gathering systems that would create additional competition for the services we provide to our customers. Because our customers do not have leases that cover the entirety of our areas of mutual interest, non-customer producers that lease acreage within any of our areas of mutual interest may choose to use one of our competitors for their gathering and/or processing service needs.

In addition, our customers may develop their own gathering systems outside of our areas of mutual interest. Our ability to renew or replace existing contracts with our customers at rates sufficient to maintain current revenues and cash flows could be materially adversely affected by the activities of our competitors and our customers. All of these competitive pressures could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

We may not be able to renew or replace expiring contracts at favorable rates or on a long-term basis.

Our gathering, treating, transportation and processing contracts have terms of various durations. As these contracts expire, we may have to negotiate extensions or renewals with existing customers or enter into new contracts with other customers. We may be unable to obtain new contracts on favorable commercial terms, if at all. We also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of our contract portfolio. Moreover, we may be unable to obtain areas of mutual interest from new customers in the future, and we may be unable to renew existing areas of mutual interest with current customers as and when they expire. The extension or replacement of existing contracts depends on a number of factors beyond our control, including:

- the level of existing and new competition to provide gathering and/or processing services in our areas of operation;
- the macroeconomic factors affecting gathering, treating, transporting and processing economics for our current and potential customers;
- the balance of supply and demand, on a short-term, seasonal and long-term basis, in our markets;
- the extent to which the customers in our areas of operation are willing to contract on a long-term basis; and
- the effects of federal, state or local regulations on the contracting practices of our customers.

To the extent we are unable to renew our existing contracts on terms that are favorable to us or successfully manage our overall contract mix over time, our revenues and cash flows could decline and our ability to make cash distributions to our unitholders could be materially adversely affected.

If third-party pipelines or other midstream facilities interconnected to our gathering systems become partially or fully unavailable, our revenues and cash flows and our ability to make cash distributions to our unitholders could be materially adversely affected.

Our gathering systems connect to third-party pipelines and other midstream facilities, such as processing plants, rail terminals and produced water disposal facilities. The continuing operation of such third-party pipelines and other midstream facilities is not within our control. These pipelines and other midstream facilities may become unavailable due to issues including, but not limited to, testing, turnarounds, line repair, reduced operating pressure, lack of operating capacity, regulatory requirements, curtailments of receipt or deliveries due to insufficient capacity or because of damage from other hazards. In addition, we do not have interconnect agreements with all of these pipelines and other facilities and the agreements we do have may be terminated in certain circumstances and/or on short notice. If any of these pipelines or other midstream facilities become unavailable for any reason, or, if these third parties are otherwise unwilling to receive or transport the natural gas, crude oil and produced water that we gather and/or process, our revenues, cash flows and ability to make cash distributions to our unitholders could be materially adversely affected.

Crude oil and natural gas production and gathering may be adversely affected by weather conditions and terrain, which in turn could negatively impact the operations of our gathering, treating, transportation and processing facilities and our construction of additional facilities.

Extended periods of below freezing weather and unseasonably wet weather conditions, especially in North Dakota, Ohio and West Virginia, can be severe and can adversely affect crude oil and natural gas operations due to the potential shut-in of producing wells or decreased drilling activities. These types of interruptions could result in a decrease in the volumes supplied to our gathering systems. Further, delays and shutdowns caused by severe weather may have a material negative impact on the continuous operations of our gathering, treating, transporting and processing systems, including interruptions in service. These types of interruptions could negatively impact our ability to meet our contractual obligations to our customers and thereby give rise to certain termination rights and/or the release of dedicated acreage. Any resulting terminations or releases could materially adversely affect our business and results of operations.

We also may be required to incur additional costs and expenses in connection with the design and installation of our facilities due to their locations and surrounding terrain. We may be required to install additional facilities, incur additional capital and operating expenditures, or experience interruptions in or impairments of our operations to the extent that the facilities are not designed or installed correctly. For example, certain of our pipeline facilities are located in mountainous areas such as our Utica Shale and Marcellus Shale operations, which may require specially designed facilities and special installation considerations. If such facilities are not designed or installed correctly, do not perform as intended, or fail, we may be required to incur significant expenditures to correct or repair the deficiencies, or may incur significant damages to or loss of facilities, and our operations may be interrupted as a result of deficiencies or failures. In addition, such deficiencies may cause damage to the surrounding environment, including slope failures, stream impacts and other natural resource damages, and we may as a result also be subject to increased operating expenses or environmental penalties and fines.

Interruptions in operations at any of our facilities may adversely affect our operations and cash flows available for distribution to our unitholders.

Our operations depend upon the infrastructure that we have developed and constructed. Any significant interruption at any of our gathering, treating, transporting or processing facilities, or in our ability to provide gathering, treating, transporting or processing services, could adversely affect our operations and cash flows available for distribution to our unitholders. Operations at our facilities could be partially or completely shut down, temporarily or permanently, as the result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at our physical plants or pipeline facilities;
- restrictions imposed by governmental authorities or court proceedings;
- labor difficulties that result in a work stoppage or slowdown;
- a disruption in the supply of resources necessary to operate our midstream facilities;
- damage to our facilities resulting from production volumes that do not comply with applicable specifications; and
- inadequate transportation and/or market access to support production volumes, including lack of pipeline, rail terminals, produced water disposal facilities and/or third-party processing capacity.

Any significant interruption at any of our gathering, treating, transporting or processing facilities, or in our ability to provide gathering, treating, transporting or processing services, could adversely affect our operations and cash flows available for distribution to our unitholders.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant incident or event occurs for which we are not adequately insured or if we fail to recover all anticipated insurance proceeds for significant incidents or events for which we are insured, our operations and financial results could be materially adversely affected.

Our operations are subject to all of the risks and hazards inherent in the operation of gathering, treating, transporting and processing systems, including:

- damage to pipelines, processing plants, compression assets, related equipment and surrounding properties caused by tornadoes, floods, fires and other natural disasters and acts of terrorism;
- inadvertent damage from construction, vehicles, farm and utility equipment;
- leaks or losses resulting from the malfunction of equipment or facilities;
- ruptures, fires and explosions; and

- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage. The location of certain of our systems in or near populated areas, including residential areas, commercial business centers and industrial sites, could increase the damages resulting from such events.

These events may also result in curtailment or suspension of our operations. A natural disaster or any event such as those described above affecting the areas in which we and our customers operate could have a material adverse effect on our operations. Accidents or other operating risks could further result in loss of service available to our customers. Such circumstances, including those arising from maintenance and repair activities, could result in service interruptions on portions or all of our gathering systems. Potential customer impacts arising from service interruptions on segments of our gathering systems could include limitations on our ability to satisfy customer requirements, obligations to temporarily waive MVCs during times of constrained capacity, temporary or permanent release of production dedications, and solicitation of existing customers by others for potential new projects that would compete directly with our existing services. Such circumstances could materially adversely impact our ability to meet contractual obligations and retain customers, with a resulting negative impact on our business and results of operations and our ability to make cash distributions to our unitholders.

Although we have a range of insurance programs providing varying levels of protection for public liability, damage to property, loss of income and certain environmental hazards, we may not be insured against all causes of loss, claims or damage that may occur. If a significant incident or event occurs for which we are not fully insured, it could materially adversely affect our operations and financial condition. Furthermore, we may not be able to maintain or obtain insurance of the type and amount we desire at reasonable rates. As a result of industry or market conditions, some of which are beyond our control, premiums and deductibles for certain of our insurance policies may substantially increase. In some instances, certain insurance could become unavailable or available only for reduced amounts of coverage. Additionally, with regard to the assets we have acquired, we have limited indemnification rights to recover from the seller of the assets in the event of any potential environmental liabilities.

We may fail to successfully integrate gathering system acquisitions into our existing business in a timely manner, which could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders, or fail to realize all of the expected benefits of the acquisitions, which could negatively impact our future results of operations.

Integration of future gathering system acquisitions could be a complex, time-consuming and costly process, particularly if the acquired assets significantly increase our size and/or (i) diversify the geographic areas in which we operate or (ii) the service offerings that we provide.

The failure to successfully integrate the acquired assets with our existing business in a timely manner may have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders. If any of the risks described above or in the immediately preceding risk factor or unanticipated liabilities or costs were to materialize with respect to future acquisitions or if the acquired assets were to perform at levels below the forecasts we used to evaluate them, then the anticipated benefits from the acquisition may not be fully realized, if at all, and our future results of operations and ability to make cash distributions to unitholders could be negatively impacted.

Our construction of new assets may not result in revenue increases and will be subject to regulatory, environmental, political, legal and economic risks, which could materially adversely affect our results of operations and financial condition.

The construction of new assets, including for example, the Double E Pipeline, which was recently placed into service, involve numerous regulatory, environmental, political, legal and economic uncertainties that are beyond our control.

Such construction projects may also require the expenditure of significant amounts of capital, and financing, traditional or otherwise, may not be available on economically acceptable terms or at all. If we undertake these projects, our revenue may not increase immediately upon the expenditure of funds for a particular project and they may not be completed on schedule, at the budgeted cost, or at all.

Moreover, we could construct facilities to capture anticipated future production growth in a region where such growth does not materialize or only materializes over a period materially longer than expected. To the extent we rely on estimates of future production in our decision to construct additions to our systems, such estimates may prove to be inaccurate due to the numerous uncertainties inherent in estimating quantities of future production. As a result, new facilities may not attract enough throughput to achieve our expected investment return, which could materially adversely affect our results of operations and financial condition.

In addition, the construction of additions or modifications to our existing gathering, treating, transporting and processing assets and the construction of new midstream assets may require us to obtain federal, state and local regulatory environmental or other authorizations. The approval process for gathering, treating, transporting and processing activities has become increasingly challenging, due in part to state and local concerns related to unregulated exploration and production and gathering, treating, transporting and processing activities in new production areas. Such authorization may not be granted or, if granted, such authorization may include burdensome or expensive conditions. As a result, we may be unable to obtain such authorizations and may, therefore, be unable to connect new volumes to our systems or capitalize on other attractive expansion opportunities. A future government shutdown could delay the receipt of any federal regulatory approvals. Additionally, it may become more expensive for us to obtain authorizations or to renew existing authorizations. If the cost of renewing or obtaining new authorizations increases materially, our cash flows could be materially adversely affected.

We do not own all of the land on which our pipelines and facilities are located, which could result in disruptions to our operations.

We do not own all of the land on which our pipelines and facilities have been constructed, and we are, therefore, subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if we do not have valid rights-of-way or if such rights-of-way lapse or terminate or if our pipelines are not properly located within the boundaries of such rights-of-way. We obtain the rights to construct and operate our pipelines on land owned by third parties and governmental agencies either perpetually or for a specific period of time. If we were to be unsuccessful in renegotiating rights-of-way, we might have to relocate our facilities. Our loss of these rights, through our inability to renew right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition and ability to make cash distributions to our unitholders.

Our ability to operate our business effectively could be impaired if we fail to attract and retain key personnel, and a shortage of skilled labor in the midstream energy industry could reduce employee productivity and increase costs, which could have a material adverse effect on our business and results of operations.

Our ability to operate our business and implement our strategies depends on our continued ability to attract and retain highly skilled personnel with midstream energy industry experience and competition for these persons in the midstream energy industry is intense. Given our size, we may be at a disadvantage, relative to our larger competitors, in the competition for these personnel. We may not be able to continue to employ our senior executives and key personnel or attract and retain qualified personnel in the future, and our failure to retain or attract our senior executives and key personnel could have a material adverse effect on our ability to effectively operate our business.

Furthermore, as a result of the COVID-19 pandemic, we have experienced difficulty in recruiting and hiring skilled labor throughout our organization. The operation of gathering, treating, transporting and processing systems requires skilled laborers in multiple disciplines such as equipment operators, mechanics and engineers, among others. If we continue to experience shortages of skilled labor in the future, our labor and overall productivity or costs could be materially adversely affected. If our labor prices increase or if we experience materially increased health and benefit costs with respect to our General Partner's employees, our business and results of operations and our ability to make cash distributions to our unitholders could be materially adversely affected.

Risks Related to Our Finances

Limited access to and/or availability of the debt and equity capital markets could impair our ability to grow or cause us to be unable to meet future capital requirements.

To expand our asset base, whether through acquisitions or organic growth, we will need to make expansion capital expenditures. We also frequently consider and enter into discussions with third parties regarding potential acquisitions. In addition, the terms of certain of our gathering and processing agreements also require us to spend significant amounts of capital, over a short period of time, to construct and develop additional midstream assets to support our customers' development projects. Depending on our customers' future development plans, it is possible that the capital required to construct and develop such assets could exceed our ability to finance those expenditures using our cash reserves or available capacity under the ABL Facility or the Permian Transmission Credit Facility.

We plan to use cash from operations, incur borrowings and/or sell additional common units or other securities to fund our future expansion capital expenditures. Using cash from operations to fund expansion capital expenditures will directly reduce any cash available for distribution to unitholders, if any. Our ability to obtain financing or to access the capital markets for future debt or equity offerings may be limited by (i) our financial condition at the time of any such financing or offering, (ii) covenants in our debt agreements, (iii) restrictions imposed by our Series A Preferred Units, (iv) general economic conditions and contingencies, (v) increasing disfavor among many investors towards investments in fossil fuel companies and (vi) general weakness in the debt and equity capital markets and other uncertainties that are beyond our control. In addition, lenders are facing increasing pressure to curtail their lending activities to companies in the oil and natural gas industry. Furthermore, market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our expansion capital expenditures and acquisition capital expenditures with the issuance of additional equity.

We have not made a distribution on our common units or Series A Preferred Units since we announced suspension of those distributions on May 3, 2020, and these suspensions of distributions may further reduce demand for our common units or Series A Preferred Units. Further, we may not pay distributions on the common units or Series A Preferred Units in the foreseeable future, and there are restrictions on our ability to pay distributions under our outstanding indebtedness that restrict our ability to pay cash distributions on any of our equity securities. As such, if we are unable to raise expansion capital, we may lose the opportunity to make acquisitions, pursue new organic development projects, or to gather, treat and process new production volumes from our customers with whom we have agreed to construct and develop midstream assets in the future. Even if we are successful in obtaining external funds for expansion capital expenditures through the capital markets, the terms thereof could limit our ability to pay distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional units representing limited partner interests may result in significant common unitholder dilution and increase the aggregate amount of cash required to pay distributions to our unitholders, which could materially decrease our ability to pay such distributions.

We have a significant amount of indebtedness. Our leverage and debt service obligations may adversely affect our financial condition, results of operations and business prospects, and may limit our flexibility to obtain financing and to pursue other business opportunities.

At December 31, 2021, we had $1.4 billion of indebtedness outstanding and the unused portion of the ABL Facility totaled $109.1 million after giving effect to the issuance of $23.9 million in outstanding but undrawn irrevocable standby letters of credit. See Note 8 - Debt of the notes to our consolidated financial statements included in Item 8 of this Annual Report for further discussion of our debt obligations. Our existing and future debt services obligations could have significant consequences, including among other things:

- limiting our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes and/or obtaining such financing on favorable terms;
- reducing our funds available for operations, future business opportunities and cash distributions to unitholders by that portion of our cash flow required to make interest payments on our debt;
- increasing our vulnerability to competitive pressures or a downturn in our business or the economy generally; and
- limiting our flexibility in responding to changing business and economic conditions.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business and other factors, many of which are beyond our control, such as commodity prices and governmental regulation.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness.

Our ability to make scheduled payments on, or to refinance, our indebtedness obligations, including the ABL Facility, the 2026 Secured Notes and the 2025 Senior Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our operating cash flows and capital resources are insufficient to fund our debt service obligations, we may be forced to adopt alternative financing strategies, such as reducing or delaying investments and capital expenditures, selling assets, seeking additional capital or restructuring or refinancing our indebtedness, some or all of which may not be available to us on terms acceptable to us, if at all, or such alternative strategies may yield insufficient funds to make required payments on our indebtedness.

Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets, including the market for senior secured or unsecured notes, and our financial condition at the time. Any refinancing of our indebtedness could be at higher interest rates, may require the pledging of collateral and may require us to comply with more onerous covenants than we are currently subject to, which could further restrict our business operations. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations.

The 2026 Secured Notes Indenture and the ABL Facility place certain restrictions on our ability to dispose of assets and our use of the proceeds from such dispositions. We may not be able to consummate those dispositions on terms acceptable to it, if at all, and the proceeds of any such dispositions may not be adequate to meet any debt service obligations then due.

Further, if for any reason we are unable to meet our debt service and principal repayment obligations, or if we fail to comply with the financial covenants in the documents governing our debt, we would be in default under the terms of the agreements governing our debt, which would allow our creditors under those agreements to declare all outstanding indebtedness thereunder to be due and payable (which would in turn trigger cross-acceleration or cross-default rights among our other debt agreements), the lenders under the ABL Facility could terminate their commitments to extend credit, and the lenders could foreclose against our assets securing their borrowings and we could be forced into bankruptcy or liquidation. If the amounts outstanding under our debt agreements were to be accelerated, we cannot assure you that our assets would be sufficient to repay in full the amounts owed to our creditors.

Restrictions in the Permian Transmission Credit Facility, the indenture governing the 2025 Senior Notes, the ABL Facility and the 2026 Secured Notes Indenture could materially adversely affect our business, financial condition, results of operations, ability to satisfy these obligations to make cash distributions to unitholders and value of our common units.

We are dependent upon the earnings and cash flows generated by our operations to meet our debt service obligations and to make cash distributions to our unitholders, if any. The operating and financial restrictions and covenants in the Permian Transmission Credit Facility, the indenture governing the 2025 Senior Notes, the ABL Facility, the 2026 Secured Notes Indenture and any future financing agreements could restrict our ability to finance future operations or capital needs or to expand or pursue our business activities, which may, in turn, limit our ability to satisfy our obligations and make cash distributions to our unitholders. For example, the ABL Facility, the Permian Transmission Credit Facility, the 2026 Secured Notes Indenture and the indenture governing the 2025 Senior Notes, taken together, restrict our ability to, among other things:

- incur or guarantee certain additional debt;
- make certain cash distributions on or redeem or repurchase certain units;
- make payments on certain other indebtedness;
- make certain investments and acquisitions;
- make certain capital expenditures;
- incur certain liens or other encumbrances or permit them to exist;
- enter into certain types of transactions with affiliates;
- enter into sale and lease-back transactions and certain operating leases;
- merge or consolidate with another company or otherwise engage in a change of control transaction; and

- transfer, sell or otherwise dispose of certain assets.

The ABL Facility also contains covenants requiring Summit Holdings to maintain certain financial ratios and meet certain tests. Summit Holdings' ability to meet those financial ratios and tests can be affected by events beyond its control, and we cannot guarantee that Summit Holdings will meet those ratios and tests.

The provisions of the Permian Transmission Credit Facility, the indenture governing the 2025 Senior Notes, the ABL Facility and the 2026 Secured Notes Indenture may affect our ability to obtain future financing and pursue attractive business opportunities as well as affect our flexibility in planning for, and reacting to, changes in business conditions. In addition, a failure to comply with the provisions of the Permian Transmission Credit Facility, the indenture governing the 2025 Senior Notes, the ABL Facility and the 2026 Secured Notes Indenture could result in a default or an event of default that could enable our lenders and/or senior noteholders to declare the outstanding principal of that debt, together with accrued and unpaid interest, to be immediately due and payable. If we were unable to repay the accelerated amounts, the lenders under the ABL Facility could proceed against the collateral granted to them to secure such debt. If the payment of the debt is accelerated, our assets may be insufficient to repay such debt in full, and our unitholders could experience a partial or total loss of their investment. The ABL Facility also has cross default provisions that apply to any other indebtedness we may have and the indenture governing the 2025 Senior Notes and the 2026 Secured Notes Indenture have cross default provisions that apply to certain other indebtedness. Any of these restrictions in the ABL Facility, the Permian Transmission Credit Facility, the 2026 Secured Notes Indenture and the indenture governing the 2025 Senior Notes could materially adversely affect our business, financial condition, cash flows and results of operations.

An increase in inflation could have adverse effects on our results of operation.

The annual rate of inflation in the United States hit 7.5% in January 2022, the highest in more than three decades, as measured by the Consumer Price Index. We expect that inflation in 2022 will increase our labor and other operating costs and the overall cost of capital projects we undertake. An increase in inflation rates could negatively affect the Partnership's profitability and cash flows, due to higher wages, higher operating costs, higher financing costs, and/or higher supplier prices. The Partnership may be unable to pass along such higher costs to its customers. In addition, inflation may adversely affect customers' financing costs, cash flows, and profitability, which could adversely impact their operations and the Partnership's ability to offer credit and collect receivables.

An increase in interest rates will cause our debt service obligations to increase.

Borrowings under the ABL Facility bear interest at a rate equal to, at our option, prime plus a margin or LIBOR plus margin. The interest rate is subject to adjustment based on fluctuations in LIBOR (or successor rates thereto) or the prime rate, as applicable. An increase in the interest rates associated with our floating rate debt would increase our debt service costs and affect our results of operations and cash flow available for payments of our debt obligations. In addition, an increase in interest rates could adversely affect our future ability to obtain financing or materially increase the cost of any additional financing.

Furthermore, the Financial Conduct Authority in the United Kingdom has phased out LIBOR as a benchmark for one-week and two-month tenors and announced that it will cease to publish all other LIBOR tenors on June 30, 2023. The ABL Facility includes a mechanism to automatically amend the ABL Facility to use an alternate rate of interest based on the secured overnight financing rate upon the occurrence of certain events related to the phase-out of LIBOR. Even where we have entered into interest rate swaps or other derivative instruments for purposes of managing our interest rate exposure, our hedging strategies may not be effective as a result of the replacement or phasing out of LIBOR, and we may incur losses as a result. In addition, the overall financial markets may be disrupted as a result of the phase-out or replacement of LIBOR. The potential increase in our interest expense as a result of the phase-out of LIBOR and uncertainty as to the nature of such potential phase-out and alternative reference rates or disruption in the financial market could have an adverse effect on our financial condition, results of operations and cash flows.

A downgrade of our credit rating could impact our liquidity, access to capital and our costs of doing business, and independent third parties determine our credit ratings outside of our control.

Moody's, S&P and Fitch assign ratings to our senior unsecured credit from time to time. A downgrade of our credit rating could increase our future cost of borrowing and could require us to post collateral with third parties, including our hedging arrangements, which could negatively impact our available liquidity and increase our cost of debt. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when we are experiencing significant working capital requirements or otherwise lacking liquidity, our results of operations, financial condition and cash flows could be adversely affected.

We have in the past and may in the future incur losses due to impairment in the carrying value of our long-lived assets or equity method investments.

We recorded long-lived asset impairments of $10.2 million in 2021. When evidence exists that we will not be able to recover a long-lived asset's carrying value through future cash flows, we write down the carrying value of the asset to its estimated fair value. We test long-lived assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. With respect to property, plant and equipment and our amortizing intangible assets, the carrying value of a long-lived asset is not recoverable if the carrying value exceeds the sum of the undiscounted cash flows expected to result from the asset's use and eventual disposal. In this situation, we recognize an impairment loss equal to the amount by which the carrying value exceeds the asset's fair value. We determine fair value using either a market-based approach, an income-based approach in which we discount the asset's expected future cash flows to reflect the risk associated with achieving the underlying cash flows, or a mixture of both market- and income-based approaches. We evaluate our equity method investment for impairment whenever events or circumstances indicate that a decline in fair value is other than temporary. Any impairment determinations involve significant assumptions and judgments. If actual results are not consistent with our assumptions and estimates, or our assumptions and estimates change due to new information, we may be exposed to impairment charges. Adverse changes in our business or the overall operating environment, such as lower commodity prices, may affect our estimate of future operating results, which could result in future impairment due to the potential impact on our operations and cash flows.

A portion of our revenues are directly exposed to changes in crude oil, natural gas and NGL prices, and our exposure may increase in the future.

During the year ended December 31, 2021, we derived 22% of our revenues from (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds or other processing arrangements with certain of our customers in the Rockies, Permian, and Piceance segments, (ii) the sale of natural gas we retain from certain Barnett customers, (iii) the sale of condensate we retain from our gathering services in the Piceance segment and (iv) additional gathering fees that are tied to performance of certain commodity price indexes, which are then added to the fixed gathering rates.. Consequently, our existing operations and cash flows have direct exposure to commodity price risk. Although we will seek to limit our commodity price exposure with new customers in the future, our efforts to obtain fee-based contractual terms may not be successful or the local market for our services may not support fee-based gathering and processing agreements. For example, we have percent-of-proceeds contracts with certain natural gas producer customers and we may, in the future, enter into additional percent-of-proceeds contracts with these customers or other customers or enter into keep-whole arrangements, which would increase our exposure to commodity price risk, as the revenues generated from those contracts directly correlate with the fluctuating price of the underlying commodities.

Furthermore, we may acquire or develop additional midstream assets in the future that have a greater exposure to fluctuations in commodity price risk than our current operations. Future exposure to the volatility of natural gas and crude oil prices could have a material adverse effect on our business, results of operations and financial condition. For example, for a small portion of the natural gas gathered on our systems, we purchase natural gas from producers prior to delivering the natural gas to pipelines where we typically resell the natural gas under arrangements including sales at index prices. Generally, the gross margins we realize under these arrangements decrease in periods of low natural gas prices. If we expand the implementation of such natural gas purchase and sale arrangements within our business, such fluctuations could materially affect our business.

Regulatory and Environmental Policy Risks

We settled a matter that was previously under investigation by federal and state regulatory agencies regarding a pipeline rupture and release of produced water by one of our subsidiaries. The resulting compliance requirements of the settlement may impact our results of operations or cash flows.

As further described in Item 3. Legal Proceedings, we settled an incident involving a produced water disposal pipeline owned by Meadowlark Midstream that resulted in a discharge of materials into the environment which was investigated by federal and state agencies. This settlement resulted in losses amounting to $36.3 million and will be paid over six years and requires compliance with certain conditions and terms and conditions which may impact our results of operations or cash flows.

We may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business. As a result, we may be required to expend significant funds for legal defense or to settle claims. Any such loss, if incurred, could be material.

Expenditures made by the Partnership for the payment of litigation related costs, including legal defense costs and settlement payments, if any, reduce our cash flows available for debt service and distributions to our unitholders, if any. Any such expenditures, if incurred, could be material. See Item 3. Legal Proceedings for additional disclosure by the Partnership regarding its ongoing litigation and claims.

A change in laws and regulations applicable to our assets or services, or the interpretation or implementation of existing laws and regulations may cause our revenues to decline or our operation and maintenance expenses to increase.

Various aspects of our operations are subject to regulation by the various federal, state and local departments and agencies that have jurisdiction over participants in the energy industry. The regulation of our activities and the natural gas and crude oil industries frequently change as they are reviewed by legislators and regulators. For example, PHMSA has issued new proposed and final rules concerning pipeline safety in recent years. In November 2021, PHMSA issued a final rule that extended pipeline safety requirements to onshore gas gathering pipelines. The rule requires all onshore gas gathering pipeline operators to comply with PHMSA's incident and annual reporting requirements. It also extends existing pipeline safety requirements to a new category of gas gathering pipelines, "Type C" lines, which generally include high-pressure pipelines that are larger than 8.625 inches in diameter. Safety requirements applicable to Type C lines vary based on pipeline diameter and potential failure consequences. The final rule becomes effective in May 2022 and operators must comply with the applicable safety requirements by November 2022. To the extent these or other new proposed or final rules create additional requirements for our pipelines, they could have a material adverse effect on our operations, operating and maintenance expenses and revenues. For additional information on the potential risks associated with PHMSA requirements, see the "We may incur greater than anticipated costs and liabilities as a result of pipeline safety requirements" section of Item 1A. Risk Factors.

In addition, the adoption of proposals for more stringent legislation, regulation or taxation of drilling activity could directly curtail such activity or increase the cost of drilling, resulting in reduced levels of drilling activity and therefore reduced demand for our services. For example, Colorado Senate Bill 19-181, signed into law in April 2019, changed the mandate of the COGCC from fostering oil and gas development to regulating oil and gas development in a reasonable manner to protect public health and the environment. The new law also allows local governments to impose more restrictive requirements on oil and gas operations than those issued by the state. As part of its implementation of this new law, in November 2020 the COGCC adopted new regulations that increase oil and gas setbacks to a minimum of 2,000 feet from schools and childcare facilities, prohibit routine venting and flaring, increase wildlife protections, and alter certain aspects of the permitting process. These regulations and similar efforts in Colorado and elsewhere could restrict oil and gas development in the future. Regulatory agencies establish and, from time to time, change priorities, which may result in additional burdens on us, such as additional reporting requirements and more frequent audits of operations. Our operations and the markets in which we participate are affected by these laws, regulations and interpretations and may be affected by changes to them or their implementation, which may cause us to realize materially lower revenues or incur materially increased operation and maintenance costs or both.

Increased regulation of hydraulic fracturing could result in reductions or delays in customer production, which could materially adversely impact our revenues.

Hydraulic fracturing is an important and increasingly common practice that is used to stimulate production of natural gas and/or crude oil from dense subsurface rock formations, and is primarily regulated by state agencies. However, Congress has in the past, and may in the future consider legislation to regulate hydraulic fracturing by federal agencies. Many states have already adopted laws and/or regulations that require disclosure of the chemicals used in hydraulic fracturing. A number of states – such as Colorado, as discussed above – have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, disclosure and well construction requirements on crude oil and/or natural gas drilling activities. For example, during the 2021-2022 election cycle, Colorado representatives proposed a ballot initiative to ban hydraulic fracturing on all non-federal land, but the proposed initiative has yet to garner significant support. States also could elect to prohibit hydraulic fracturing altogether, as New York, Maryland, and Vermont have done. In addition, certain local governments have adopted, and additional local governments may adopt, ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. These initiatives and similar efforts in Colorado and elsewhere could restrict oil and gas development in the future.

The EPA has also moved forward with various regulatory actions, including a proposal to issue new regulations under the New Source Performance Standards (NSPS) to expand and strengthen emissions reduction requirements under NSPS OOOOa for new, modified and reconstructed oil and natural gas sources, and require states to reduce methane emissions from existing sources nationwide. For further discussion of NSPS OOOOa and subsequent actions by the EPA, see the "Environmental Matters—Air Emissions" section of Item 1. Business of this Annual Report. The BLM has also asserted regulatory authority over aspects of the hydraulic fracturing process, and issued a final rule in March 2015 that established more stringent standards for performing hydraulic fracturing on federal and Indian lands, including requirements relating to well construction and integrity, handling of wastewater and chemical disclosure. However, in December 2017, the BLM published a final rule rescinding the 2015 rule. The U.S. District Court for the Northern District of California upheld the December 2017 rescission rule in a March 2020 decision, and the State of California and environmental plaintiffs appealed. Litigation is currently ongoing.

Further, several federal governmental agencies have conducted reviews and studies on the environmental aspects of hydraulic fracturing, including the EPA. The results of such reviews or studies could spur initiatives to further regulate hydraulic fracturing.

State and federal regulatory agencies recently have focused on a possible connection between the hydraulic fracturing related activities and the increased occurrence of seismic activity. When caused by human activity, such events are called induced seismicity. Some state regulatory agencies, including those in Colorado, Ohio, and Texas, have modified their regulations or guidance to account for induced seismicity. These developments could result in additional regulation and restrictions on the use of injection disposal wells and hydraulic fracturing. Such regulations and restrictions could cause delays and impose additional costs and restrictions on our customers.

Additionally, certain of our customers produce oil and gas on federal lands. On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order effectively suspending new fossil fuel leasing and permitting on federal lands for 60 days. Then on January 27, 2021, President Biden issued an executive order indefinitely suspending new oil and natural gas leases on public lands or in offshore waters pending completion of a comprehensive review and reconsideration of federal oil and gas permitting and leasing practices. Several states filed lawsuits challenging the suspension, and on June 15, 2021, a judge in the U.S. District Court for the Western District of Louisiana issued a nationwide temporary injunction blocking the suspension. The Department of the Interior appealed the U.S. District Court's ruling, but resumed oil and gas leasing pending resolution of the appeal. In November 2021, the Department of the Interior completed its review and issued a report on the federal oil and gas leasing program. The Department of the Interior's report recommends several changes to federal leasing practices, including changes to royalty payments, bidding, and bonding requirements.

If new or more stringent federal, state or local legal restrictions relating to drilling activities or to the hydraulic fracturing process are adopted, this could result in a reduction in the supply of natural gas and/or crude oil that our customers produce, and could thereby adversely affect our revenues and results of operations. Compliance with such rules could also generally result in additional costs, including increased capital expenditures and operating costs, for our customers, which could ultimately decrease end-user demand for our services and could have a material adverse effect on our business.

We are subject to FERC jurisdiction, federal anti-market manipulation laws and regulations, potentially other federal regulatory requirements and state and local regulation and could be materially affected by changes in such laws and regulations, or in the way they are interpreted and enforced.

We believe that our natural gas pipeline facilities qualify as gathering facilities that are exempt from the jurisdiction of FERC under the NGA and the NGPA. Interstate movements of crude oil on the Epping Pipeline in North Dakota are subject to FERC jurisdiction under the ICA, and the rates, terms and conditions of service, and practices on the pipeline are subject to review and challenge before FERC.

Additionally, the Double E Project, which provides interstate natural gas transmission service from southeastern New Mexico to the Waha hub in Texas, is subject to FERC jurisdiction under the NGA with respect to post-construction remediation activities, operations, and rates and terms and conditions of service. Pursuant to the NGA, Double E Pipeline's existing interstate natural gas transportation rates and terms and conditions of service may be challenged by complaint and are subject to prospective change by FERC. Additionally, rate changes and changes to terms and conditions of service proposed by a regulated natural gas interstate pipeline may be protested and such changes can be delayed and may ultimately be rejected by FERC. FERC may also initiate reviews of an interstate pipeline's rates. We cannot guarantee that any new or existing tariff rate for service on our FERC-regulated pipelines would not be rejected or modified by the FERC, or subjected to refunds. Any successful challenge by a regulator or shipper in any of these matters could have a material adverse effect on our business, financial condition and results of operations.

We have certain long-term fixed priced natural gas and crude oil transportation contracts that cannot be adjusted even if our costs increase. As a result, our costs could exceed our revenues. In 2021, we entered into negotiated rate agreements with an average term of 10 years from the in-service date of the pipeline, which occurred on November 18, 2021 and with total MDTQ's that increases from 585,000 Dth/d during the first year of the agreement to 1,000,000 Dth/d in the fourth year, which equates to approximately 74% of its certificated capacity of 1,350,000 Dth/d, these contracts are not subject to adjustment, even if our cost to perform such services exceeds the revenues received from such contracts, and, as a result, our costs could exceed our revenues received under such contracts. It is possible that costs to perform services under our "negotiated or discount rate" contracts will exceed the negotiated or discounted rates. It is also possible with respect to discounted rates that if our filed "recourse rates" should ever be reduced below applicable discounted rates, we would only be allowed by FERC to charge the lower recourse rates, since FERC policy does not allow discount rates to be charged to the extent that they exceed applicable recourse rates. If these events were to occur, it could decrease the cash flow realized by our assets.

Under FERC policy, a regulated service provider and a customer may mutually agree to sign a contract for service at a "negotiated rate," which is generally fixed between the natural gas pipeline and the shipper for the contract term and does not necessarily vary with changes in the level of cost-based “recourse rates,” provided that the affected customer is willing to agree to such rates and that the FERC has accepted the negotiated rate agreement. These “negotiated or discount rate” contracts are not generally subject to adjustment for increased costs which could be caused by inflation or other factors relating to the specific facilities being used to perform the services. Any shortfall of revenue, representing the difference between “recourse rates” (if higher) and negotiated or discounted rates, under current FERC policy, may be recoverable from other shippers in certain circumstances. For example, the FERC may recognize this shortfall in the determination of prospective rates in a future rate case. However, if the FERC were to disallow the recovery of such costs from other customers, it could decrease the cash flow realized by our assets.

We are also generally subject to the anti-market manipulation provisions in the NGA, as amended by the Energy Policy Act of 2005, and to FERC’s regulations thereunder, and also must comply with the other applicable provisions of the NGA and NGPA and FERC’s rules, regulations, and orders concerning the Double E Pipeline’s interstate natural gas pipeline business, including those that require us to provide firm and interruptible transportation service on an open access basis that is not unduly discriminatory or preferential. Violations of the NGA or NGPA, or the rules, regulations, and orders issued by FERC thereunder could result in the imposition of administrative and criminal remedies, including without limitation, revocation of certain authorities, disgorgement of ill-gotten gains, and civil penalties of up to $1,388,496 per day per violation of the NGA or its implementing regulations, subject to future adjustment for inflation. In addition, the FTC holds statutory authority under the Energy Independence and Security Act of 2007 to prevent market manipulation in oil markets, and has adopted broad rules and regulations prohibiting fraud and market manipulation. The FTC is also authorized to seek fines of up to $1,323,791 per violation, subject to future adjustment for inflation. The CFTC is directed under the CEA to prevent price manipulation in the commodity, futures and swaps markets, including the energy markets. Pursuant to the Dodd-Frank Act, and other authority, the CFTC has adopted additional anti-market manipulation regulations that prohibit fraud and price manipulation in the commodity, futures and swaps markets. The CFTC also has statutory authority to seek civil penalties of up to the greater of $1,303,559 per violation, subject to future adjustment for inflation, or triple the monetary gain to the violator for each violation of the anti-market manipulation provisions of the CEA.

The distinction between federally unregulated natural gas and crude oil pipelines and FERC-regulated natural gas and crude oil pipelines has been the subject of extensive litigation and is determined by FERC on a case-by-case basis. FERC has made no determinations as to the status of our facilities. Consequently, the classification and regulation of some of our pipelines could change based on future determinations by FERC, Congress or the courts. If our natural gas gathering operations or crude oil operations beyond the Epping Pipeline become subject to FERC jurisdiction under the NGA, the NGPA or the ICA, the result may materially adversely affect the rates we are able to charge and the services we currently provide, and may include the potential for a termination of our gathering agreements with our customers. In addition, if any of our facilities were found to have provided services or otherwise operated in violation of the NGA, the NGPA or the ICA, this could result in the imposition of civil penalties, as well as a requirement to disgorge charges collected for such services in excess of the rate established by FERC.

We are subject to state and local regulation regarding the construction and operation of our gathering, treating, transporting and processing systems, as well as state ratable take statutes and regulations. Regulation of the construction and operation of our facilities may affect our ability to expand our facilities or build new facilities and such regulation may cause us to incur additional operating costs or limit the quantities of natural gas and crude oil we may gather, treat and process. Ratable take statutes and regulations generally require gatherers to take natural gas and crude oil production that may be tendered for gathering without undue discrimination. These requirements restrict our right to decide whose production we gather, treat and process. Many states have adopted complaint-based regulation of gathering, treating, transporting and processing activities, which allows producers and shippers to file complaints with state regulators in an effort to resolve access issues, rate grievances and other matters. Other state and municipal regulations do not directly apply to our business, but may nonetheless affect the availability of natural gas and crude oil for gathering, treating, transporting and processing, including state regulation of production rates, maximum daily production allowable from wells, and other activities related to drilling and operating wells. While our facilities currently are subject to limited state and local regulation, there is a risk that state or local laws will be changed or reinterpreted, which may materially affect our operations, operating costs and revenues.

Recent actions by the FERC may affect rates on Epping Pipeline, Double E Pipeline and other future FERC-regulated pipelines.

On March 15, 2018, FERC announced a revised policy prohibiting FERC-jurisdictional natural gas and liquids pipelines owned by master limited partnerships from including an allowance for income taxes in the cost of service used to calculate tariff rates. Most of our pipelines are not subject to FERC regulation and so will not be affected by the revised policy statement. However, rates for interstate movements of crude oil on our Epping Pipeline in North Dakota and any future FERC-regulated pipelines may be affected by the application of the revised policy statement in subsequent FERC proceedings.

FERC has not required regulated interstate oil pipelines to decrease their rates on an industry-wide basis to implement the new policy. However, FERC stated that the effects of the revised policy statement must be incorporated in annual FERC financial reports made by regulated interstate oil pipelines. These reports, which also reflected the impact of the corporate income tax reduction enacted as part of the Tax Reform Legislation, were considered by FERC in its five-year review and determination of the index rate adjustment, which resulted in the December 17, 2020 order adopting a new annual index adjustment for the five-year period starting July 1, 2021. FERC ultimately removed the effect of the income tax allowance policy change from its index calculation, although the December 17, 2020 order is subject to rehearing and possible judicial review. The impact of these future proceedings on Epping Pipeline and any future FERC-regulated pipelines is uncertain at this time.

Until FERC sets the next index rate adjustment, Epping Pipeline and any future FERC-regulated pipelines may face an increased risk of shipper complaints seeking FERC review of its rates. FERC can also initiate review of rates on its own initiative. We could also propose new cost-of-service rates or changes to our existing rates that would be subject to review by FERC under its new policy. No such proceedings have occurred at this time, however, and the potential outcome of any such proceedings, should any materialize, is uncertain. As a result of any such proceedings, Epping Pipeline and any future FERC-regulated pipelines may be required to modify their rates, which could affect the revenues we generate with our Epping Pipeline and any future FERC-regulated pipelines. At this time, we do not expect any such proceedings would have a material adverse effect, but we intend to monitor FERC developments and provide updated disclosure, as necessary.

We are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our gathering, treating, transporting and processing operations are subject to stringent and complex federal, state and local environmental laws and regulations, including laws and regulations regarding the discharge of materials into the environment or otherwise relating to environmental protection, including, for example, the CAA, CERCLA, the CWA, the OPA, the RCRA, the Endangered Species Act and the Toxic Substances Control Act.

These laws and regulations may impose numerous obligations that are applicable to our operations, including the acquisition of permits to conduct regulated activities, the incurrence of capital or operating expenditures to limit or prevent releases of materials from our pipelines and facilities, and the imposition of substantial liabilities and remedial obligations for pollution resulting from our operations or at locations currently or previously owned or operated by us. For additional information on specific laws and regulations, see the “Environmental Matters” section of Item 1. Business. Numerous governmental authorities, such as the EPA and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly corrective actions or costly pollution control measures. Failure to comply with these laws, regulations and requisite permits may result in the assessment of significant administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of injunctions limiting or preventing some or all of our operations. In addition, we may experience a delay in obtaining or be unable to obtain required permits or regulatory authorizations, which may cause us to lose potential and current customers, interrupt our operations and limit our growth and revenue.

There is a risk that we may incur significant environmental costs and liabilities in connection with our operations due to historical industry operations and waste disposal practices, our handling of hydrocarbons and other wastes and potential emissions and discharges related to our operations. Joint and several, strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of hydrocarbon wastes on, under or from our properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under our control. Private parties, including the owners of the properties through which our gathering systems pass, and on which certain of our facilities are located, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. In addition, changes in environmental laws occur frequently, and any such changes that result in additional permitting obligations or more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations or financial position. We may not be able to recover all or any of these costs from insurance.

The new presidential administration and Democratic control of Congress resulting from the 2020 elections may result in increased restrictions on oil and gas production activities, which could materially adversely affect our industry and our financial condition and results of operations.

We may incur greater than anticipated costs and liabilities as a result of pipeline safety requirements.

The DOT, through PHMSA, has adopted and enforces safety standards and procedures applicable to our pipelines. In addition, many states, including the states in which we operate, have adopted regulations that are identical to or more restrictive than existing DOT regulations for intrastate pipelines. Among the regulations applicable to us, PHMSA requires pipeline operators to develop integrity management programs for certain pipelines located in high consequence areas, which include high population areas such as the Dallas-Fort Worth greater metropolitan area where our DFW Midstream system is located. While the majority of our pipelines have historically met the DOT definition of gathering lines and were thus exempt from PHMSA's integrity management requirements, we also operate a limited number of pipelines that are subject to the integrity management requirements. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- maintain processes for data collection, integration and analysis;
- repair and remediate pipelines as necessary;
- adopt and maintain procedures, standards and training programs for control room operations; and
- implement preventive and mitigating actions.

In addition, PHMSA has taken recent action to regulate gathering systems, which includes integrity management requirements. In November 2021, PHMSA issued a final rule that all extended pipeline safety requirements to onshore gas gathering pipelines. The rule requires all onshore gas gathering pipeline operators to comply with PHMSA’s incident and annual reporting requirements. It also extends existing pipeline safety requirements to a new category of gas gathering pipelines, “Type C” lines, which generally include high-pressure pipelines that are larger than 8.625 inches in diameter. Safety requirements applicable to Type C lines vary based on pipeline diameter and potential failure consequences. The final rule becomes effective in May 2022 and operators must comply with the applicable safety requirements by November 2022.

For additional information on PHMSA regulations relating to pipeline safety, see the “Regulation of the Natural Gas and Crude Oil Industries—Safety and Maintenance” section of Item 1. Business.

PHMSA has also imposed additional requirements on onshore gas transmission systems and hazardous liquids pipelines in recent years. In July 2018, the PHMSA issued an advance notice of proposed rulemaking seeking comment on the class location requirements for natural gas transmission pipelines, and particularly the actions operators must take when class locations change due to population growth or building construction near the pipeline. The associated notice of proposed rulemaking, issued October 14, 2020, proposes to amend the requirements for gas transmission pipeline segments that experience a change in class location by offering an alternative set of requirements operators could use, based on implementing integrity management principles and pipe eligibility criteria, to manage certain pipeline segments where the class location has changed from a Class 1 location to a Class 3 location. In October 2019, the PHMSA issued three new final rules. One rule, which became effective in December 2019, established procedures to implement the expanded emergency order enforcement authority set forth in an October 2016 interim final rule. Among other things, this rule allows the PHMSA to issue an emergency order without advance notice or opportunity for a hearing. The other two rules, which became effective in July 2020, imposed several new requirements on operators of onshore gas transmission systems and hazardous liquids pipelines. The rule concerning gas transmission extends the requirement to conduct integrity assessments beyond “high consequence areas” (HCAs) to pipelines in “moderate consequence areas” (MCAs). It also includes requirements to reconfirm Maximum Allowable Operating Pressure (MAOP), report MAOP exceedances, consider seismicity as a risk factor in integrity management, and use certain safety features on in-line inspection equipment. The rule concerning hazardous liquids extends the required use of leak detection systems beyond HCAs to all regulated non-gathering hazardous liquid pipelines, requires reporting for gravity fed lines and unregulated gathering lines, requires periodic inspection of all lines not in HCAs, calls for inspections of lines after extreme weather events, and adds a requirement to make all lines in or affecting HCAs capable of accommodating in-line inspection tools over the next 20 years. Further, in December 2020, the Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2020 became law, reauthorizing PHMSA for funding through 2023 and requiring, among other things, rulemaking to amend the integrity management program, emergency response plan, operation and maintenance manual, and pressure control recordkeeping requirements for gas distribution operators; to create new leak detection and repair program obligations; and to set new minimum federal safety standards for onshore gas gathering lines. While we believe that we are in compliance with existing safety laws and regulations, increased penalties for safety violations and potential regulatory changes could have a material adverse effect on our operations, operating and maintenance expenses and revenues.

Climate change legislation, regulatory initiatives and litigation could result in increased operating costs and reduced demand for the services we provide.

In recent years, the U.S. Congress has considered legislation to restrict or regulate emissions of GHGs, such as carbon dioxide and methane that may be contributing to global warming and energy legislation and other initiatives are expected to be proposed that may be relevant to GHG emissions issues. For example, the revisions to the NSPS found in 40 CFR 60 subpart OOOO (and OOOOa) include emission reduction requirements. In November 2021, the EPA issued a new proposed rule targeting methane emissions from new and existing oil and gas sources. The proposed rule would: (1) update NSPS OOOOa; (2) adopt a new NSPS OOOOb for sources that commence construction, modification or reconstruction after the date the proposed rule is published in the Federal Register; and (3) adopt a new NSPS OOOOc to establish emissions guidelines, which will inform state plans to establish standards for existing sources.

In addition, almost half of the states, either individually or through multi-state regional initiatives, have begun to address GHG emissions, primarily through the planned development of emission inventories or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and gas processing plants, to acquire and surrender emission allowances. In general, the number of allowances available for purchase is reduced each year until the overall GHG emission reduction goal is achieved. Depending on the scope of a particular program, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations (e.g., at compressor stations). It is possible that certain components of our operations, such as our gas-fired compressors, could become subject to state-level GHG-related regulation. For example, in May 2021, as part of a Governor-directed statewide initiative to reduce GHG emissions by at least 45% by 2030, the New Mexico Environment Department (“NMED”) proposed new rules that would establish emissions standards for VOCs and nitrogen oxides for oil and gas production and processing sources located in certain areas of the state with high ozone concentrations. NMED conducted a public hearing on the proposed rules in September 2021 and the rules are expected to be finalized and issued in 2022. Although we cannot currently determine the effect of these proposed regulations and other regulatory initiatives to implement the Governor’s directive to reduce GHG emissions, they could, if implemented, be material to the business, reputation, financial condition or results of operations of our Summit Permian system. Similarly, in April 2021, the New Mexico Department of Energy, Minerals, and Natural Resources (“EMNRD”) finalized new rules concerning venting and flaring of natural gas. EMNRD’s final rule may impose new or increased costs and obligations on our customers, which could reduce demand for our services and negatively impact our revenues and results of operations.

Independent of Congress, the EPA has adopted regulations under its existing CAA authority. In 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources of GHG emissions. For additional information on EPA regulations adopted under the CAA, see the “Environmental Matters—Climate Change” section of Item 1. Business. Further, in December 2015, over 190 countries, including the United States, reached an agreement to reduce global GHG emissions. The agreement entered into force in November 2016 after over 70 countries, including the United States, ratified or otherwise consented to be bound by the agreement. In November 2019, the United States submitted formal notification to the United Nations that it intended to withdraw from the agreement. However, on January 20, 2021, President Biden signed an “Acceptance on Behalf of the United States of America” that, reversed the prior withdrawal, and the United States officially rejoined the Paris Agreement on February 19, 2021. As part of rejoining the Paris Agreement, President Biden announced that the United States would commit to a 50 to 52 percent reduction from 2005 levels of GHG emissions by 2030, and set the goal of reaching net-zero GHG emissions by 2050. In addition, shortly after taking office in January 2021, President Biden issued a series of executive orders designed to address climate change. New legislation to regulate GHG emissions has also been periodically introduced in the United States Congress, but none have passed. Reentry into the Paris Agreement, new legislation, or President Biden’s executive orders may result in the development of additional regulations or changes to existing regulations, which could have a material adverse effect on our business and that of our customers.

Although it is not possible at this time to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business, either directly or indirectly, any future federal or state laws or implementing regulations that may be adopted to address GHG emissions could require us to incur increased operating costs and could materially adversely affect demand for our services. The potential increase in the costs of our operations resulting from any legislation or regulation to restrict emissions of GHG could include new or increased costs to operate and maintain our facilities, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions, adhere to alternative energy requirements and administer and manage a GHG emissions program. While we may be able to include some or all of such increased costs in the rates we charge, such recovery of costs is uncertain. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for our services. We cannot predict with any certainty at this time how these possibilities may affect our operations. Finally, most scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. We cannot predict with any certainty at this time how these possibilities may affect our operations.

The implementation of statutory and regulatory requirements for swap transactions could have an adverse impact on our ability to hedge risks associated with our business and increase the working capital requirements to conduct these activities.

Congress adopted comprehensive financial reform legislation under the Dodd-Frank Act that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. This legislation requires the CFTC and the SEC and other regulatory authorities to promulgate certain rules and regulations, including rules and regulations relating to the regulation of certain swaps market participants, such as swap dealers, the clearing of certain swaps through central counterparties, the execution of certain swaps on designated contract markets or swap execution facilities, mandatory margin requirements for uncleared swaps, and the reporting and recordkeeping of swaps. While most of the regulations have been promulgated and are already in effect, the rulemaking and implementation process is still ongoing. Moreover, CFTC continues to refine its initial rulemakings under the Dodd-Frank Act. As a result, we cannot yet predict the ultimate effect of the rules and regulations on our business and while most of the regulations have been adopted, any new regulations or modifications to existing regulations could increase the cost of derivative contracts, limit the availability of derivatives to protect against risks that we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties.

The CFTC has proposed federal position limits on certain core futures and equivalent swaps contracts in the major energy and other markets, with exceptions for certain bona fide hedging transactions provided that various conditions are satisfied. If finalized, the position limits rule and its companion rule on aggregation among entities under common ownership or control may have an impact on our ability to hedge our exposure to certain enumerated commodities.

In 2013, the CFTC implemented final rules regarding mandatory clearing of certain classes of interest rate swaps and certain classes of index credit default swaps. Mandatory trading on designated contract markets or swap execution facilities of certain interest rate swaps and index credit default swaps also began in 2014. At this time, the CFTC has not proposed any rules designating other classes of swaps, including physical commodity swaps, for mandatory clearing. The CFTC and prudential banking regulators also recently adopted mandatory margin requirements on uncleared swaps between swap dealers and certain other counterparties. Although we may qualify for a commercial end-user exception from the mandatory clearing, trade execution and uncleared swaps margin requirements, mandatory clearing and trade execution requirements and uncleared swaps margin requirements applicable to other market participants, such as swap dealers, may affect the cost and availability of the swaps that we use for hedging.

Under the Dodd-Frank Act, the CFTC is also directed generally to prevent price manipulation and fraud in the following two markets: (a) physical commodities traded in interstate commerce, including physical energy and other commodities, as well as (b) financial instruments, such as futures, options and swaps. Pursuant to the Dodd-Frank Act, the CFTC has adopted additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets. Should we violate these laws and regulations, we could be subject to CFTC enforcement action and material penalties, and sanctions.

We currently enter into forward contracts with third parties to buy power and sell natural gas in an attempt to mitigate our exposure to fluctuations in the price of natural gas with respect to those volumes. The CFTC has finalized an interpretation clarifying whether certain forwards with volumetric optionality are regulated as forwards or qualify as options on commodities and therefore swaps. This interpretation may have an impact on our ability to enter into certain forwards or may impose additional requirements with respect to certain transactions.

In addition to the Dodd-Frank Act, the European Union and other foreign regulators have adopted and are implementing local reforms generally comparable with the reforms under the Dodd-Frank Act. Implementation and enforcement of these regulatory provisions may reduce our ability to hedge our market risks with non-U.S. counterparties and may make any transactions involving cross-border swaps more expensive and burdensome. Additionally, the lack of regulatory equivalency across jurisdictions may increase compliance costs and make it more costly to satisfy regulatory obligations.

We may face opposition to the development, permitting, construction or operation of our pipelines and facilities from various groups.

We may face opposition to the development, permitting, construction or operation of our pipelines and facilities from environmental groups, landowners, local groups and other advocates. Such opposition could take many forms, including organized protests, attempts to block or sabotage our operations, intervention in regulatory or administrative proceedings involving our assets, or lawsuits or other actions designed to prevent, disrupt or delay the development or operation of our assets and business. For example, repairing our pipelines often involves securing consent from individual landowners to access their property; one or more landowners may resist our efforts to make needed repairs, which could lead to an interruption in the operation of the affected pipeline or other facility for a period of time that is significantly longer than would have otherwise been the case. In addition, acts of sabotage or eco-terrorism could cause significant damage or injury to people, property or the environment or lead to extended interruptions of our operations. Any such event that interrupts the revenues generated by our operations, or which causes us to make significant expenditures not covered by insurance, could reduce our cash available for paying distributions to our unitholders and, accordingly, have a material adverse effect on our business, financial condition and results of operations. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we require to conduct our operations to be withheld, delayed or burdened by requirements that restrict our ability to profitably conduct our business.

For example, in an April 15, 2020 ruling, amended May 11, 2020, the U.S. District Court for the District of Montana issued an order invalidating the U.S. Army Corps of Engineers ("Corps") 2017 reissuance of Nationwide Permit 12 ("NWP 12"), the general permit governing discharges of dredged or fill material associated with pipeline and other utility line construction projects, to the extent it was used to authorize construction of new oil and gas pipelines. Environmental groups had alleged that the Corps failed to consult with federal wildlife agencies as required by the Endangered Species Act. The court's decision vacated NWP 12 until the Corps completes consultation with the applicable federal wildlife agencies. On July 6, 2020, the U.S. Supreme Court granted in part the Corps' request to stay the U.S. District Court's decision to allow the use of NWP 12 for utility line activities, including new oil and gas pipelines, pending the outcome of the appeal to the U.S. Court of Appeals for the Ninth Circuit and any subsequent petition for review to the U.S. Supreme Court. Litigation is currently ongoing. In January 2021, the EPA and Corps reissued NWP 12 as a general permit specific to oil and gas pipelines, moving other utility line activities into separate general permits. In May 2021, environmental groups once again filed suit in the U.S. District Court for the District of Montana, seeking vacatur of the reissued NWP 12. Environmental groups allege that the reissuance of NWP 12 violated the Endangered Species Act, National Environmental Policy Act, and Clean Water Act, among other things. Litigation is ongoing. In the meantime, the Corps has announced that it will be reviewing all the nationwide permits for consistency with Administration policies, which could result in additional limitations on the use of nationwide permits. Limitations on the use of NWP 12 may make it more difficult to permit our projects, require consideration of alternative construction or siting, which may impose additional costs and delays, and could cause us to lose potential and current customers and limit our growth and revenue.

In addition, on July 6, 2020, the U.S. District Court for the District of Columbia issued an order vacating a Corps Mineral Leasing Act easement for the Dakota Access Pipeline in a lawsuit filed by American Indian Tribes. The court's decision requires the pipeline to shut down operations by August 5, 2020, but was stayed by the U.S. Court of Appeals for the District of Columbia Circuit. On January 26, 2021, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision affirming the district court's holding that the easement should be vacated, but reversing the requirement to shut down the pipeline. The Court of Appeals left it to the Corps to determine how to proceed after the loss of the easement, and while the Corps declined to shut down the pipeline, it did not formally approve the pipeline's ongoing operation without an easement. The Dakota Access Pipeline continues to operate pending the Corps' ongoing development of a court-ordered environmental impact statement for the project, which is expected to be finished in 2022. If the Dakota Access Pipeline is forced to shut down, this could have a material adverse effect on our business, financial condition and results of operations associated with the Polar and Divide system, which interconnects with the Dakota Access Pipeline.

Recently, activists concerned about the potential effects of climate change have directed their attention towards sources of funding for fossil-fuel energy companies, which has resulted in an increasing number of financial institutions, funds, individual investors and other sources of capital restricting or eliminating their investment in fossil fuel-related activities. In addition, financial institutions have begun to screen companies such as ours for sustainability performance, including practices related to GHGs and climate change, before providing loans or investing in our common units. There is also a risk that financial institutions may adopt policies that have the effect of reducing the funding provided to the fossil fuel sector, such as the adoption of net zero financed emissions targets. Such policies may be hastened by actions under the Biden Administration, including the implementation by the Federal Reserve of any recommendations made by the Network for Greening the Financial System, a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Ultimately, this could make it more difficult to secure funding for exploration and production activities or energy infrastructure related projects, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects. Any efforts to improve our sustainability practices in response to these pressures may increase our costs, and we may be forced to implement technologies that are not economically viable in order to improve our sustainability performance and to meet the specific requirements to maintain access to capital or perform services for certain customers.

Our business is subject to complex and evolving U.S. and International laws and regulations regarding privacy and data protection ("data protection laws"). Many of these laws and regulations are subject to change and uncertain interpretation, and could result in claims, increased cost of operations or otherwise harm our business.

Along with our own data and information in the normal course of our business, we and our partners collect and retain significant volumes of certain types of data, some of which are subject to specific laws and regulations. The transfer and use of this data both domestically and across international borders is becoming increasingly complex. The regulatory environment surrounding and the transfer and protection of such data is constantly evolving and can be subject to significant change. New data protection laws at the federal, state, international, national, provincial and local levels, including recent Colorado legislation, the European Union General Data Protection Regulation ("GDPR") and the California Consumer Privacy Act ("CCPA"), pose increasingly complex compliance challenges and potentially elevate our costs.

Complying with these jurisdictional requirements could increase the costs and complexity of compliance, and violations of applicable data protection laws can result in significant penalties. For example, the GDPR applies to activities regarding personal data that may be conducted by us, directly or indirectly through vendors and subcontractors, from an establishment in the European Union. Failure to comply could result in significant penalties of up to a maximum of 4% of our global turnover that may materially adversely affect our business, reputation, results of operations, and cash flows. Similarly, the CCPA, which came into effect on January 1, 2020, gives California residents specific rights in relation to their personal information, requires that companies take certain actions, including notifications for security incidents and may apply to activities regarding personal information that is collected by us, directly or indirectly, from California residents. As interpretation and enforcement of the CCPA evolves, it creates a range of new compliance obligations, which could cause us to change our business practices, with the possibility for significant financial penalties for noncompliance that may materially adversely affect our business, reputation, results of operations, and cash flows.

As noted above, we are also subject to the possibility of information security breaches, which themselves may result in a violation of these laws. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

Risks Inherent in an Investment in Us

Because our common units are yield-oriented securities, increases in interest rates could materially adversely impact our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions to our unitholders.

Interest rates were generally near historic lows in 2021 and may increase in the future. As with other yield-oriented securities, our unit price is impacted by the level of our cash distributions and implied distribution yield. The distribution yield is often used by investors to compare and rank yield-oriented securities for investment decision-making purposes. Therefore, changes in interest rates, either positive or negative, may affect the yield requirements of investors who invest in our common units, and a rising interest rate environment could have a material adverse impact on our unit price, our ability to issue equity or incur debt for acquisitions or other purposes and our ability to make cash distributions at our intended levels.

The amount of cash we have available for distribution to holders of our units depends primarily on our cash flows rather than on our profitability, which may prevent us from making distributions, even during periods in which we record net income.

The amount of cash we have available for distribution depends primarily upon our cash flows and not solely on profitability, which will be affected by non-cash items. As a result, we may make cash distributions during periods when we report net losses for GAAP purposes and may not make cash distributions during periods when we report net income for GAAP purposes.

The market price of our common units may fluctuate significantly and, due to limited daily trading volumes, an investor could lose all or part of its investment in us.

An investor may not be able to resell its common units at or above its acquisition price. Additionally, limited liquidity may result in wide bid-ask spreads, contribute to significant fluctuations in the market price of the common units and limit the number of investors who are able to buy the common units.

The market price of our common units may decline and be influenced by many factors, some of which are beyond our control, including among others:

- our quarterly distributions, if any;
- our quarterly or annual earnings or those of other companies in our industry;
- the loss of a large customer;

- announcements by our customers or others regarding our customers or changes in our customers' credit ratings, liquidity position, leverage profile and/or other financial or credit-related metrics;
- announcements by our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic and geopolitical conditions;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts; and
- other factors described in these Risk Factors.

Our Partnership Agreement replaces our General Partner's fiduciary duties to unitholders and those of our officers and directors with contractual standards governing their duties.

Our Partnership Agreement contains provisions that eliminate fiduciary duties to which our General Partner and its officers and directors would otherwise be held by state fiduciary duty law and replaces those duties with several different contractual standards.

By purchasing a common unit, a common unitholder agrees to become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Our Partnership Agreement limits the liabilities of our General Partner and its officers and directors and the rights of our unitholders with respect to actions taken by our General Partner and its officers and directors that might otherwise constitute breaches of fiduciary duty.

Our Partnership Agreement contains provisions that limit the liability of our General Partner and the rights of our unitholders with respect to actions taken by our General Partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law. For example, our Partnership Agreement provides that:

- whenever our General Partner makes a determination or takes, or declines to take, any other action in its capacity as our General Partner, our General Partner is required to make such determination, or take or decline to take such other action, in good faith, meaning that it subjectively believed that the decision was in our best interests, and will not be subject to any other or different standard imposed by our Partnership Agreement, Delaware law, or any other law, rule or regulation, or at equity;
- our General Partner will not have any liability to us or our unitholders for decisions made in its capacity as a General Partner so long as such decisions are made in good faith;
- our General Partner and its officers and directors will not be liable for monetary damages to us, our limited partners or their assignees resulting from any act or omission unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that our General Partner or its officers and directors, as the case may be, acted in bad faith or engaged in fraud or willful misconduct or, in the case of a criminal matter, acted with knowledge that the conduct was criminal; and
- our General Partner will not be in breach of its obligations under the Partnership Agreement or its duties to us or our unitholders if a transaction with an affiliate or the resolution of a conflict of interest is:
    i. approved by the Conflicts Committee, if established, although our General Partner is not obligated to seek such approval;
    ii. approved by the vote of a majority of the outstanding common units, excluding any common units owned by our General Partner and its affiliates;
    iii. on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or
    iv. fair and reasonable to us, taking into account the totality of the relationships among the parties involved, including other transactions that may be particularly favorable or advantageous to us.

In connection with a situation involving a transaction with an affiliate or a conflict of interest, any determination by our General Partner or the Conflicts Committee must be made in good faith. If an affiliate transaction or the resolution of a conflict of interest is not approved by our common unitholders or the Conflicts Committee and the Board of Directors determines that the resolution or course of action taken with respect to the affiliate transaction or conflict of interest satisfies either of the standards set forth in the final two subclauses above, then it will be presumed that, in making its decision, the Board of Directors acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Our Partnership Agreement restricts the voting rights of unitholders owning 20% or more of our common units.

Unitholders' voting rights are further restricted by a provision of our Partnership Agreement providing that any person or group that owns 20% or more of any class of units then outstanding cannot vote on any matter, other than our General Partner, its affiliates, their transferees and persons who acquired such units with the prior approval of the Board of Directors.

We may issue additional units without unitholder approval, which would dilute existing ownership interests.

Except in the case of the issuance of units that rank equal to or senior to the Series A Preferred Units, our Partnership Agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units that we may issue at any time without the approval of our unitholders.

As a result of the 2022 Preferred Exchange Offer (as defined herein), as of January 14, 2022, we have outstanding Series A Preferred Units having an issue price of less than $100 million. As a result, under our Partnership Agreement, we may now issue additional securities in parity with the Series A Preferred Units without any vote of the holders of the Series A Preferred Units (except where the cumulative distributions on the Series A Preferred Units or any parity securities are in arrears) and without the approval of holders of our common units.

We may issue additional Series A Preferred Units and any securities in parity with the Series A Preferred Units without any vote of the holders of the Series A Preferred Units (except where the cumulative distributions on the Series A Preferred Units or any parity securities are in arrears and in certain other circumstances) and without the approval of our common unitholders.

The issuance by us of additional common units or other equity securities of equal or senior rank will decrease our existing unitholders' proportionate ownership interest in us. In addition, the issuance by us of additional common units or other equity securities of equal or senior rank may have the following effects:

- decreasing the amount of cash available for distribution on each unit;
- increasing the ratio of taxable income to distributions;
- diminishing the relative voting strength of each previously outstanding unit; and
- causing the market price of the common units to decline.

Future issuances and sales of parity securities, or the perception that such issuances and sales could occur, may cause prevailing market prices for our common units and the Series A Preferred Units to decline and may adversely affect our ability to raise additional capital in the financial markets at times and prices favorable to us.

Furthermore, the payment of distributions on any additional units may increase the risk that we will not be able to make distributions at our prior per unit distribution levels. To the extent new units are senior to our common units, including units issued to third parties at a subsidiary level, their issuance will increase the uncertainty of the payment of distributions on our common units.

Holders of Series A Preferred Units have limited voting rights, which may be diluted.

Although holders of the Series A Preferred Units are entitled to limited voting rights with respect to certain matters, the Series A Preferred Units generally vote separately as a class along with any other series of our parity securities that we may issue upon which like voting rights have been conferred and are exercisable. As a result, the voting rights of holders of Series A Preferred Units may be significantly diluted, and the holders of such other series of parity securities that we may issue may be able to control or significantly influence the outcome of any vote.

Our General Partner has a limited call right that may require an investor to sell its units at an undesirable time or price.

If at any time our General Partner and its affiliates own more than 80% of our outstanding common units, our General Partner will have the right, which it may assign to any of its affiliates or to us, but not the obligation, to acquire all, but not less than all, of the common units held by unaffiliated persons at a price that is not less than their then-current market price, as calculated pursuant to the terms of our Partnership Agreement. As a result, an investor may be required to sell its common units at an undesirable time or price and may not receive any return on its investment. An investor may also incur a tax liability upon a sale of its units.

An investor's liability may not be limited if a court finds that unitholder action constitutes control of our business.

A General Partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the General Partner. Our partnership is organized under Delaware law, and we conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which we do business. An investor could be liable for any and all of our obligations as if it was a General Partner if a court or government agency were to determine that:

- we were conducting business in a state but had not complied with that particular state's partnership statute; or
- an investor's right to act with other unitholders to remove or replace our General Partner, to approve some amendments to our Partnership Agreement or to take other actions under our Partnership Agreement constitute control of our business.

Our Partnership Agreement designates the Court of Chancery of the State of Delaware as the exclusive forum for certain types of actions and proceedings that may be initiated by our unitholders, which limits our unitholders' ability to choose the judicial forum for disputes with us or our General Partner's directors, officers or other employees.

Our Partnership Agreement provides that, with certain limited exceptions, the Court of Chancery of the State of Delaware is the exclusive forum for any claims, suits, actions or proceedings (1) arising out of or relating in any way to our Partnership Agreement (including any claims, suits or actions to interpret, apply or enforce the provisions of our Partnership Agreement or the duties, obligations or liabilities among our partners, or obligations or liabilities of our partners to us, or the rights or powers of, or restrictions on, our partners or us), (2) brought in a derivative manner on our behalf, (3) asserting a claim of breach of a duty (including a fiduciary duty) owed by any of our, or our General Partner's, directors, officers, or other employees, or owed by our General Partner, to us or our partners, (4) asserting a claim against us arising pursuant to any provision of the Delaware Revised Uniform Limited Partnership Act or (5) asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in our common units is deemed to have received notice of and consented to the foregoing provisions. This exclusive forum provision does not apply to a cause of action brought under federal or state securities laws. Although management believes this choice of forum provision benefits us by providing increased consistency in the application of Delaware law in the types of lawsuits to which it applies, the provision may have the effect of discouraging lawsuits against us and our General Partner's directors and officers. The enforceability of similar choice of forum provisions in other companies' certificates of incorporation or similar governing documents has been challenged in legal proceedings and it is possible that in connection with any action a court could find the choice of forum provisions contained in our Partnership Agreement to be inapplicable or unenforceable in such action. If a court were to find this choice of forum provision inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our financial position, results of operations and ability to make cash distributions to our unitholders.

Unitholders may have liability to repay distributions that were wrongfully distributed to them.

Under certain circumstances, unitholders may have to repay amounts wrongfully returned or distributed to them. Under Delaware law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets. Delaware law provides that for a period of three years from the date of an impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable both for the obligations of the assignor to make contributions to the partnership that were known to the substituted limited partner at the time it became a limited partner and for those obligations that were unknown if the liabilities could have been determined from the Partnership Agreement. Neither liabilities to partners on account of their partnership interest nor liabilities that are non-recourse to the partnership are counted for purposes of determining whether a distribution is permitted.

If an investor is not an eligible holder, it may not receive distributions or allocations of income or loss on those common units and those common units will be subject to redemption.

We have adopted certain requirements regarding those investors who may own our common units and Series A Preferred Units. Eligible holders are U.S. individuals or entities subject to U.S. federal income taxation on the income generated by us or entities not subject to U.S. federal income taxation on the income generated by us, so long as all of the entity's owners are U.S. individuals or entities subject to such taxation. If an investor is not an eligible holder, our General Partner may elect not to make distributions or allocate income or loss on that investor's units, and it runs the risk of having its units redeemed by us at the lower of purchase price cost or the then-current market price. The redemption price may be paid in cash or by delivery of a promissory note, as determined by our General Partner.

Our Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of our common units.

The Series A Preferred Units rank senior to our common units with respect to distribution rights and rights upon liquidation. These preferences could adversely affect the market price for our common units or could make it more difficult for us to sell our common units in the future.

In addition, (i) prior to December 15, 2022, distributions on the Series A Preferred Units accumulate and are cumulative at the rate of 9.50% per annum of $1,000, the liquidation preference of the Series A Preferred Units and (ii) on and after December 15, 2022, distributions on the Series A Preferred Units will accumulate for each distribution period at a percentage of

$1,000 equal to the three-month LIBOR plus a spread of 7.43%. We have not made a distribution on our common units or Series A Preferred Units since we announced suspension of those distributions on May 3, 2020. As of December 31, 2021, the amount of accrued and unpaid distributions on the Series A Preferred Units was $29.9 million. Unpaid distributions on the Series A Preferred Units will continue to accrue.

In addition, our Subsidiary Series A Preferred Units issued by Permian Holdco have priority over the common unitholders with respect to the cash flow from Permian Holdco. The distribution rate of the Subsidiary Series A Preferred Units is 7.00% per annum of the $1,000 issue amount per outstanding Subsidiary Series A Preferred Unit. Permian Holdco has the option to pay this distribution in-kind until the first quarter of 2022, which is the first full quarter following the date the Double E Pipeline was placed in service.

Our obligation to pay distributions on our Series A Preferred Units and Permian Holdco's obligation to pay the distributions on the Subsidiary Series A Preferred Units could impact our liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Our obligations to the holders of the Series A Preferred Units and Permian Holdco's obligations to the holders of the Subsidiary Series A Preferred Units could also limit our ability to obtain additional financing or increase our borrowing costs, which could have an adverse effect on our financial condition.

Our Series A Preferred Units contain covenants that may limit our business flexibility.

Our Series A Preferred Units contain covenants preventing us from taking certain actions without the approval of the holders of 66 2/3% of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede our ability to take certain actions that management or the Board of Directors may consider to be in the best interests of our unitholders. The affirmative vote of 66 2/3% of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend the Partnership Agreement in any manner that would have a material adverse effect on the existing preferences, rights, powers, duties or obligations of the Series A Preferred Units. The affirmative vote of 66 2/3% of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) under certain circumstances, create or issue certain equity securities that are senior to our common units, (B) declare or pay any distribution to common unitholders out of capital surplus or (C) take any action that would result in an event of default for failure to comply with any covenant in the indentures governing the 5.5% Senior Notes or the 2025 Senior Notes co-issued by Summit Holdings and its 100% owned finance subsidiary, Finance Corp.

Although holders of the Series A Preferred Units are entitled to limited voting rights with respect to certain matters, the Series A Preferred Units generally vote as a class, separate from our common unitholders, along with any other series of our parity securities that we may issue upon which like voting rights have been conferred and are exercisable.

Tax Risks

Our tax treatment depends on our status as a partnership for federal income tax purposes. If the IRS were to treat us as a corporation for federal income tax purposes, which would subject us to entity-level taxation, then our cash available for distribution to our unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our units depends largely on our being treated as a partnership for federal income tax purposes.

Despite the fact that we are a limited partnership under Delaware law, it is possible in certain circumstances for a partnership such as ours to be treated as a corporation for federal income tax purposes. A change in our business or a change in current law could cause us to be treated as a corporation for federal income tax purposes or otherwise subject us to taxation as an entity.

If we were treated as a corporation for federal income tax purposes, we would pay federal income tax on our taxable income at the corporate tax rate, which is currently 21%, and would likely pay state and local income tax at varying rates. Distributions to our unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits), and no income, gains, losses, deductions, or credits would flow through to our unitholders. Because a tax would be imposed upon us as a corporation, our cash available for distribution would be substantially reduced. Therefore, if we were treated as a corporation for federal income tax purposes, there would be material reductions in the anticipated cash flow and after-tax return to our unitholders, likely causing a substantial reduction in the value of our units. This could adversely affect our financial position, results of operations and ability to make distributions to our unitholders.

If we were subjected to a material amount of additional entity-level taxation by individual states, it would reduce our cash available for distribution to our unitholders.

Changes in current state law may subject us to additional entity-level taxation by individual states. Because of widespread state budget deficits and other reasons, several states are evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution.

The tax treatment of publicly traded partnerships or an investment in our units could be subject to potential legislative, judicial or administrative changes and differing interpretations of applicable law, possibly on a retroactive basis.

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. From time to time, the President and members of the U.S. Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships.

Any modification to the U.S. federal income tax laws and interpretations could make it more difficult or impossible to meet the exception for us to be treated as a partnership for U.S. federal income tax purposes. One recent proposal was contained in the Biden Administration's budget proposal released on May 28, 2021, which would repeal the application of the qualifying income exception to partnerships with income and gains from activities relating to fossil fuels for taxable years beginning after 2026. Additionally, Senate Finance Committee Chair Ron Wyden recently proposed legislation that would repeal the application of the qualifying income exception to all partnerships for taxable years beginning after 2022. We are unable to predict whether any such changes will ultimately be enacted, but it is possible that a change in law could affect us and may, if enacted, be applied retroactively. Any such changes could negatively impact the value of an investment in our units.

Our unitholders are required to pay income taxes on their share of our taxable income even if they do not receive any cash distributions from us. A unitholder's share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, transactions in which we engage or changes in law and may be substantially different from any estimate we make in connection with a unit offering.

A unitholder's allocable share of our taxable income will be taxable to it, which may require the unitholder to pay federal income taxes and, in some cases, state and local income taxes, even if the unitholder receives cash distributions from us that are less than the actual tax liability that results from that income or no cash distributions at all.

A unitholder's share of our taxable income, and its relationship to any distributions we make, may be affected by a variety of factors, including our economic performance, which may be affected by numerous business, economic, regulatory, legislative, competitive and political uncertainties beyond our control, and certain transactions in which we might engage. For example, we may engage in transactions that produce substantial taxable income allocations to some or all of our unitholders without a corresponding increase in cash distributions to our unitholders, such as a sale or exchange of assets, the proceeds of which are reinvested in our business or used to reduce our debt, or an actual or deemed satisfaction of our indebtedness for an amount less than the adjusted issue price of the debt. A unitholder's ratio of its share of taxable income to the cash received by it may also be affected by changes in law. For instance, under Tax Reform Legislation, the net interest expense deductions of certain business entities, including us, are limited to 30% of such entity's "adjusted taxable income," which is generally taxable income with certain modifications. If the limit applies, a unitholder's taxable income allocations will be more (or its net loss allocations will be less) than would have been the case absent the limitation.

From time to time, in connection with an offering of our common units, we may state an estimate of the ratio of federal taxable income to cash distributions that a purchaser of common units in that offering may receive in a given period. These estimates depend in part on factors that are unique to the offering with respect to which the estimate is stated, so the expected ratio applicable to other common units will be different, and in many cases less favorable, than these estimates. Moreover, even in the case of common units purchased in the offering to which the estimate relates, the estimate may be incorrect, due to the uncertainties described above, challenges by the IRS to tax reporting positions which we adopt, or other factors. The actual ratio of taxable income to cash distributions could be higher or lower than expected, and any differences could be material and could materially affect the value of the common units.

We have engaged in recent transactions that generated substantial COD income on a per unit basis relative to the trading price of our common units. We may engage in other transactions that result in substantial COD income or other gains in the future, and such events may cause a unitholder to be allocated income with respect to our units with no corresponding distribution of cash to fund the payment of the resulting tax liability to the unitholder.

A unitholder's share of our taxable income will include any COD income recognized upon the satisfaction of our outstanding indebtedness for total consideration less than the adjusted issue price (and any accrued but unpaid interest) of such indebtedness. In recent years, we have engaged in various liability management transactions that resulted in substantial COD income. We may engage in other transactions that result in substantial COD income or other gains, such as gains upon assets sales, in the future. Depending upon the net amount of other items related to our loss (or income) allocable to a unitholder, any COD income or other gains may cause a unitholder to be allocated income with respect to our units with no corresponding distribution of cash to fund the payment of the resulting tax liability to the unitholder. Furthermore, such COD income event or other gain event may not be fully offset, either now or in the future, by capital losses, which are subject to significant limitations, or other losses. Accordingly, a COD income event or other gain event could cause a unitholder to realize taxable income without corresponding future economic benefits or offsetting tax deductions.

If the IRS contests the federal income tax positions we take, the market for our units may be adversely impacted and the cost of any IRS contest would likely reduce our cash available for distribution to our unitholders.

The IRS may adopt positions that differ from the conclusions of our counsel expressed in a prospectus or from the positions we take, and the IRS's positions may ultimately be sustained. It may be necessary to resort to administrative or court proceedings to sustain some or all of our counsel's conclusions or the positions we take and such positions may not ultimately be sustained. A court may not agree with some or all of our counsel's conclusions or the positions we take. Any contest with the IRS, and the outcome of any IRS contest, may have a materially adverse effect on the market for our units and the price at which they trade. In addition, our costs of any contest with the IRS would be borne indirectly by our unitholders because the costs would likely reduce our cash available for distribution.

Unitholders may be subject to limitation on their ability to deduct interest expense incurred by us.

In general, we are entitled to a deduction for interest paid or accrued on indebtedness properly allocable to our trade or business during our taxable year. However, under the Tax Reform Legislation, our deduction for "business interest" is limited to the sum of our business interest income and 30% of our "adjusted taxable income." For purposes of this limitation, our adjusted taxable income is computed without regard to any business interest expense or business interest income, and in the case of taxable years, beginning before January 1, 2022, any deduction allowable for depreciation, amortization, or depletion.

Tax gain or loss on the disposition of our units could be more or less than expected.

If a unitholder sells its units, a gain or loss will be recognized for federal income tax purposes equal to the difference between the amount realized and the unitholder's tax basis in those units. Because distributions in excess of a unitholder's allocable share of its net taxable income decrease its tax basis in its units, the amount, if any, of such prior excess distributions with respect to the units it sells will, in effect, become taxable income to the unitholder if it sells such units at a price greater than its tax basis in those units, even if the price it receives is less than its original cost. Furthermore, a substantial portion of the amount realized on any sale or other disposition of a unitholder's units, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depreciation recapture. In addition, because the amount realized includes a unitholder's share of our nonrecourse liabilities, if a unitholder sells its units, it may incur a tax liability in excess of the amount of cash it receives from the sale.

Tax-exempt entities and non-U.S. persons face unique tax issues from owning our units that may result in adverse tax consequences to them.

Investment in our units by tax-exempt entities, such as employee benefit plans and individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. For example, virtually all of our income allocated to an organization that is exempt from federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income ("UBTI") and will be taxable to the exempt organization as UBTI on the exempt organization's tax return in the year the exempt organization is allocated the income. Under the Tax Reform Legislation, an exempt organization is required to independently compute its UBTI from each separate unrelated trade or business which may prevent an exempt organization from utilizing losses we allocate to the organization against the organization's UBTI from other sources and vice versa. Distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons will be required to file federal income tax returns and applicable state tax returns and pay tax on their share of our taxable income.

Under the Tax Reform Legislation, if a unitholder sells or otherwise disposes of a unit, the transferee is required to withhold 10.0% of the amount realized by the transferor unless the transferor certifies that it is not a foreign person, and we are required to deduct and withhold from the transferee amounts that should have been withheld by the transferee but were not withheld. However, the U.S. Treasury and the IRS have suspended these rules for transfers of certain publicly traded partnership interests, including transfers of our common units, that occur before January 1, 2023. Under recently finalized Treasury Regulations, such withholding will be required on open market transactions, but in the case of a transfer made through a broker, a partner's share of liabilities will be excluded from the amount realized. In addition, the obligation to withhold will be imposed on the broker instead of the transferee (and we will generally not be required to withhold from the transferee amounts that should have been withheld by the transferee but were not withheld). These withholding obligations will apply to transfers of our common units occurring on or after January 1, 2023.

We treat each holder of our common units as having the same tax benefits without regard to the actual common units held. The IRS may challenge this treatment, which could adversely affect the value of the common units.

Because we cannot match transferors and transferees of common units and because of other reasons, we will adopt depreciation and amortization positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely affect the amount of tax benefits available to our unitholders. A successful IRS challenge also could affect the timing of these tax benefits or the amount of gain from a unitholder's sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to the unitholder's tax returns.

Treatment of distributions on our Series A Preferred Units as guaranteed payments for the use of capital creates a different tax treatment for the holders of our Series A Preferred Units than the holders of our common units and such distributions are not eligible for the 20% deduction for qualified publicly traded partnership income.

The tax treatment of distributions on our Series A Preferred Units is uncertain. We will treat the holders of Series A Preferred Units as partners for tax purposes and will treat distributions on the Series A Preferred Units as guaranteed payments for the use of capital that will generally be taxable to the holders of Series A Preferred Units as ordinary income. A holder of Series A Preferred Units may recognize taxable income from the accrual of such a guaranteed payment even in the absence of a contemporaneous distribution, and we anticipate accruing and making the guaranteed payment distributions semi-annually on the 15th day of June and December through December 15, 2022, and quarterly on the 15th day of March, June, September and December thereafter. Because the guaranteed payment for each unit must accrue as income to a holder during the taxable year of the accrual, the guaranteed payment attributable to the period beginning December 15th and ending December 31st will accrue to the holder of record of a Series A Preferred Unit on December 31st for such period. Otherwise, except in the case of our liquidation, the holders of Series A Preferred Units are generally not anticipated to share in our items of income, gain, loss or deduction. We will not allocate any share of its nonrecourse liabilities to the holders of Series A Preferred Units.

Treasury Regulations provide that a guaranteed payment for the use of capital generally is not taken into account for purposes of computing qualified business income for purposes of the 20% deduction for qualified publicly traded partnership will not constitute an allocable or distributive share of such income. As a result, the guaranteed payment for use of capital received by holders of our Series A Preferred Units may not be eligible for the 20% deduction for qualified publicly traded partnership income.

A holder of Series A Preferred Units will be required to recognize gain or loss on a sale of units equal to the difference between the holder's amount realized and tax basis in the units sold. The amount realized generally will equal the sum of the cash and the fair market value of other property such holder receives in exchange for such Series A Preferred Units. Subject to general rules requiring a blended basis among multiple partnership interests, the tax basis of a Series A Preferred Unit will generally be equal to the sum of the cash and the fair market value of other property paid by the holder to acquire such Series A Preferred Unit. Gain or loss recognized by a holder on the sale or exchange of a Series A Preferred Unit held for more than one year generally will be taxable as long-term capital gain or loss. Because holders of Series A Preferred Units will not generally be allocated a share of our items of depreciation, depletion or amortization, it is not anticipated that such holders would be required to recharacterize any portion of their gain as ordinary income as a result of the recapture rules.

Investment in the Series A Preferred Units by tax-exempt investors, such as employee benefit plans and IRAs, and non-U.S. persons raises issues unique to them. Although the issue is not free from doubt, we will treat distributions to non-U.S. holders of the Series A Preferred Units as "effectively connected income" (which will subject holders to U.S. net income taxation and possibly the branch profits tax) that are subject to withholding taxes imposed at the highest effective tax rate applicable to such non-U.S. holders. If the amount of withholding exceeds the amount of U.S. federal income tax actually due, non-U.S. holders may be required to file U.S. federal income tax returns in order to seek a refund of such excess. The treatment of guaranteed payments for the use of capital to tax-exempt investors is not certain and such payments may be treated as unrelated business taxable income for federal income tax purposes.

All holders of our Series A Preferred Units are urged to consult a tax advisor with respect to the consequences of owning our Series A Preferred Units.

We prorate our items of income, gain, loss and deduction for U.S, federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among our unitholders.

We prorate our items of income, gain, loss and deduction for U.S. federal income tax purposes between transferors and transferees of our units each month based upon the ownership of our units on the first day of each month, instead of on the basis of the date a particular unit is transferred. Treasury Regulations allow a similar monthly simplifying convention, but do not specifically authorize the use of the proration method we have adopted. If the IRS were to challenge our proration method, or if new Treasury Regulations were issued, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

A unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of those units. If so, the unitholder would no longer be treated for federal income tax purposes as a partner with respect to those units during the period of the loan and may recognize gain or loss from the disposition.

Because a unitholder whose units are loaned to a "short seller" to cover a short sale of units may be considered as having disposed of the loaned units, the unitholder may no longer be treated for federal income tax purposes as a partner with respect to those units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of our income, gain, loss or deduction with respect to those units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those units could be fully taxable as ordinary income. Therefore, unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to consult a tax advisor to discuss whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their units.

We have adopted certain valuation methodologies and monthly conventions for U.S. federal income tax purposes that may result in a shift of income, gain, loss and deduction among our unitholders. The IRS may challenge this treatment, which could adversely affect the value of our units.

When we issue additional units or engage in certain other transactions, we will determine the fair market value of our assets. Although we may from time to time consult with professional appraisers regarding valuation matters, we make many fair market value estimates using a methodology based on the market value of our units as a means to measure the fair market value of our assets. The IRS may challenge these valuation methods and the resulting allocations of income, gain, loss and deduction.

A successful IRS challenge to these methods or allocations could adversely affect the amount, character and timing of taxable income or loss being allocated to our unitholders. It also could affect the amount of taxable gain from our unitholders' sale of units and could have a negative impact on the value of the units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

If the IRS makes audit adjustments to our income tax returns, the IRS (and some states) may collect any resulting taxes (including any applicable penalties and interest) resulting from such audit adjustment directly from us, in which case we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders could be substantially reduced.

If the IRS makes audit adjustments to our income tax returns, it may collect any resulting taxes (including any applicable penalties and interest) directly from us. We will generally have the ability to shift any such tax liability to our unitholders in accordance with their interests in us during the year under audit, but there can be no assurance that we will be able to do so (and will choose to do so) under all circumstances, or that we will be able to (or choose to) effect corresponding shifts in state income or similar tax liability resulting from the IRS adjustment in states in which we do business in the year under audit or in the adjustment year. If, we make payments of taxes, penalties and interest resulting from audit adjustments, we may require our unitholders and former unitholders to reimburse us for such taxes (including any applicable penalties or interest) or, if we are required to bear such payment, our cash available for distribution to our unitholders could be substantially reduced. Additionally, we may be required to allocate an adjustment disproportionately among our unitholders, causing the publicly traded units to have different capital accounts, unless the IRS issues further guidance.

In the event the IRS makes an audit adjustment to our income tax returns and we do not or cannot shift the liability to our unitholders in accordance with their interests in us during the year under audit, we will generally have the ability to request that the IRS reduce the determined underpayment by reducing the suspended passive loss carryovers of our unitholders (without any compensation from us to such unitholders), to the extent such underpayment is attributable to a net decrease in passive activity losses allocable to certain partners. Such reduction, if approved by the IRS, will be binding on any affected unitholders.

As a result of investing in our units, our unitholders will likely be subject to state and local taxes and return filing requirements in jurisdictions where we operate or own or acquire properties.

In addition to federal income taxes, our unitholders will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we conduct business or control property now or in the future, even if the unitholders do not live in any of those jurisdictions. Our unitholders will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these various jurisdictions. Further, our unitholders may be subject to penalties for failure to comply with those requirements. Some of the states in which we conduct business currently impose a personal income tax on individuals. As we make acquisitions or expand our business, we may control assets or conduct business in additional states that impose a personal income tax. It is the unitholder's responsibility to file all federal, state and local tax returns.

Compliance with and changes in tax laws could adversely affect our performance.

We are subject to extensive tax laws and regulations, including federal and state income taxes and transactional taxes such as excise, sales/use, payroll, franchise and ad valorem taxes. New tax laws and regulations and changes in existing tax laws and regulations are continuously being enacted that could result in increased tax expenditures in the future. Many of these tax liabilities are subject to audits by the respective taxing authority. These audits may result in additional taxes as well as interest and penalties.

Risks Related to Terrorism and Cyberterrorism

Terrorist attacks and threats, escalation of military activity in response to these attacks or acts of war could have a material adverse effect on our business, financial condition or results of operations.

Terrorist attacks and threats, escalation of military activity or acts of war may have significant effects on general economic conditions, fluctuations in consumer confidence and spending and market liquidity, each of which could materially and adversely affect our business. Future terrorist attacks, rumors or threats of war, actual conflicts involving the United States or its allies, or military or trade disruptions may significantly affect our operations and those of our customers. Strategic targets, such as energy-related assets, may be at greater risk of future attacks than other targets in the United States. Disruption or significant increases in energy prices could result in government-imposed price controls. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations. Our insurance may not protect us against such occurrences.

Our operations depend on the use of information technology ("IT") systems that could be the target of a cyberattack.

The oil and gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations, including certain midstream activities. For example, software programs are used to manage gathering and transportation systems and for compliance reporting. The use of mobile communication devices has increased rapidly. Industrial control systems now control large scale processes that can include multiple sites and long distances, such as oil and gas pipelines.

Our operations depend on the use of sophisticated IT systems. Our IT systems and networks, as well as those of our customers, vendors and counterparties, may become the target of cyber-attacks or information security breaches, which in turn could result in the unauthorized release and misuse of sensitive or proprietary information as well as disrupt our operations, damage our reputation or damage our facilities or those of third parties, which could have a material adverse effect on our revenues and increase our operating and capital costs, which could reduce the amount of cash otherwise available for distribution. In addition, certain cyber-incidents, such as surveillance, may remain undetected for an extended period. We may be required to incur additional costs to modify or enhance our IT systems or to prevent or remediate any such attacks.

A cyber-incident involving our IT systems and related infrastructure, or that of our customers, venders and counterparties, could disrupt our business plans and negatively impact our operations in the following ways, among others:

- a cyber-attack on a vendor or service provider could result in supply chain disruptions, which could delay or halt development of additional infrastructure, effectively delaying the start of cash flows from the project;
- a cyber-attack on downstream pipelines could prevent us from delivering product at the tailgate of our facilities, resulting in a loss of revenues;
- a cyber-attack on a communications network or power grid could cause operational disruption, resulting in loss of revenues;
- a deliberate corruption of our financial or operational data could result in events of non-compliance, which could lead to regulatory fines or penalties; and
- business interruptions could result in expensive remediation efforts, distraction of management, damage to our reputation or a negative impact on the price of our units.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

A description of our properties is included in Item 1. Business, and is incorporated herein by reference. For additional information on our midstream assets and their capacities, see Item 1. Business.

Our real property falls into two categories: (i) parcels that we own in fee and (ii) parcels in which our interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. Portions of the land on which our gathering systems and other major facilities are located are owned by us in fee title, and we believe that we have valid title to these lands. The remainder of the land on which our major facilities are located are held by us pursuant to long-term leases or easements between us and the underlying fee owner or permits with governmental authorities. We believe that we have valid leasehold estates or fee ownership in such lands or valid permits with governmental authorities. We have no knowledge of any material challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by us or to our title to any material lease, easement, right-of-way, permit or license. We believe that we have satisfactory title to all of our material leases, easements, rights-of-way, permits and licenses with the exception of certain ordinary course encumbrances and permits with governmental entities that have been applied for, but not yet issued.

In addition, we lease various office space under leases to support our operations.

Item 3. Legal Proceedings.

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any significant legal or governmental proceedings, except as noted below. In addition, we are not aware of any significant legal or governmental proceeding contemplated to be brought against us, under the various environmental protection statutes to which we are subject, except as noted below.

Global Settlement. On August 4, 2021, the Partnership and several of its subsidiaries entered into agreements to resolve government investigations into the previously disclosed 2015 Blacktail Release, from a pipeline owned and operated by Meadowlark Midstream, which at the time was a wholly owned subsidiary of Summit Investments, (together with Meadowlark Midstream, the “Companies”). The Companies entered into the following agreements to resolve the U.S. federal and North Dakota state governments’ environmental claims against the Companies with respect to the 2015 Blacktail Release: (i) a Consent Decree with (a) the DOJ, on behalf of the U.S. Environmental Protection Agency and the U.S. Department of Interior, and (b) the State of North Dakota, on behalf of the North Dakota Department of Environmental Quality and the North Dakota Game and Fish Department, lodged with the U.S. District Court; (ii) a Plea Agreement with the United States, by and through the U.S. Attorney for the District of North Dakota, and the Environmental Crimes Section of the DOJ; and (iii) a Consent Agreement with the North Dakota Industrial Commission.

The Consent Decree provides for, among other requirements and subject to the conditions therein, (i) payment of total civil penalties and reimbursement of assessment costs of $21.25 million, with the federal portion of penalties payable over up to five years and the state portion of penalties payable over up to six years, with interest accruing at fixed rate of 3.25%; (ii) continuation of remediation efforts at the site of the 2015 Blacktail Release; (iii) other injunctive relief including but not limited to control room management, an environmental management system audit, training, and reporting; and (iv) no admission of liability to the U.S. or North Dakota. The Consent Decree was entered by the U.S. District Court on September 28, 2021.

The Consent Agreement settles a complaint brought by the NDIC in an administrative action against the Companies for alleged violations of the North Dakota Administrative Code (“NDAC”) arising from the 2015 Blacktail Release on the following terms: (i) the Companies admit to three counts of violating the NDAC; (ii) the Companies agree to follow the terms and conditions of the Consent Decree, including payment of penalty and reimbursement amounts set forth in the Consent Decree; and (iii) specified conditions in the Consent Decree regarding operation and testing of certain existing produced water pipelines shall survive until those pipelines are properly abandoned.

Under the Plea Agreement, the Companies agreed to, among other requirements and subject to the conditions therein, (i) enter guilty pleas for one charge of negligent discharge of a harmful quantity of oil and one charge of knowing failure to immediately report a discharge of oil; (ii) sentencing that includes payment of a fine of $15.0 million plus mandatory special assessments over a period of up to five years with interest accruing at the federal statutory rate; (iii) organizational probation for a minimum period of three years from sentencing, which will include payment in full of certain components of the fines and penalty amounts; and (iv) compliance with the remedial measures in the Consent Decree.

On December 6, 2021, the U.S. District Court accepted the Plea Agreement and approval of the Global Settlement is now complete.

Moore Control Systems

Separately, a demand for arbitration was filed in Houston, Texas by Moore Control Systems, Inc. against Summit Permian. The claimant in that matter was a contractor hired to perform engineering, procurement, and construction services for Summit Permian's gas processing plant located in Eddy County, New Mexico. The claimant is seeking damages for alleged non-payment for such services. We do not currently believe that the eventual outcome of this matter could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

Item 5. Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Our common units trade on the NYSE under the ticker symbol “SMLP”. As of December 31, 2021, there were approximately 15,600 common unitholders of record.

We have not made a distribution on our common units or Series A Preferred Units since we announced a suspension of those distributions on May 3, 2020.

Our Cash Distribution Policy and Restrictions on Distributions

General

Suspension of Distributions. On May 3, 2020, in connection with the GP Buy-In Transaction, the Partnership suspended distributions to holders of its common units and suspended payments of distributions to holders of its Series A Preferred Units, commencing with respect to the quarter ending March 31, 2020. Because our Series A Preferred Units rank senior to our common units with respect to distribution rights, any accrued amounts on our Series A Preferred Units must first be paid prior to our resumption of distributions to our common unitholders. As of December 31, 2021, the amount of accrued and unpaid distributions on the Series A Preferred Units totaled $29.9 million. On January 12, 2022, the Partnership completed an offer to exchange its Series A Preferred Units and accepted for exchange 77,939 Series A Preferred Units for the issuance of 2,853,875 SMLP common units, net of units withheld for withholding taxes. At this time, the Partnership is unable to forecast when it will resume distributions to holders of its common units and Series A Preferred Units.

Our Cash Distribution Policy. Our Partnership Agreement requires us to distribute all of our available cash quarterly, subject to reserves established by our General Partner. Generally, our available cash is our (i) cash on hand at the end of a quarter after the payment of our expenses and the establishment of cash reserves and (ii) cash on hand resulting from working capital borrowings made after the end of the quarter. Because we are not subject to an entity-level federal income tax, we have more cash to distribute to our unitholders than would be the case were we subject to federal income tax.

Upon a resumption of the Partnership’s distributions, we will pay our distributions on or about the 15th of each of February, May, August and November to holders of record on or about seven days prior to such distribution date. We make the distribution on the business day immediately preceding the indicated distribution date if the distribution date falls on a holiday or non-business day.

The Board of Directors plans on making decisions with respect to payment of distributions on the common units and Series A Preferred Units on a semi-annual or quarterly basis, as applicable, based on the required payment date. However, we do not intend to pay distributions on the common units or Series A Preferred Units in the foreseeable future, and there are restrictions in the agreements for our indebtedness limiting our ability to pay cash distributions on any of our equity securities.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy. There is no guarantee that our unitholders will receive quarterly distributions from us. We do not have a legal obligation to pay any distribution except to the extent we have available cash as defined in our Partnership Agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions, including the following:

- Our cash distribution policy is subject to restrictions on distributions under our ABL Facility and the 2026 Secured Notes Indenture and the indenture governing the 2025 Notes. These agreements contain financial tests, excess cash flow sweep mechanisms, and covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions notwithstanding our stated cash distribution policy.
- Our cash distribution policy is subject to restrictions on distributions under our Series A Preferred Units. Our Series A Preferred Units contain covenants that we must satisfy. Should we be unable to satisfy these restrictions, we may be prohibited from making cash distributions notwithstanding our stated cash distribution policy.
- Our General Partner has the authority to establish cash reserves for the prudent conduct of our business and for future cash distributions to our unitholders, and the establishment or increase of those cash reserves could result in a reduction in cash distributions to our unitholders from the levels we currently anticipate pursuant to our stated distribution policy. Any determination to establish cash reserves made by our General Partner in good faith will be binding on our unitholders.
- Although our Partnership Agreement requires us to distribute all of our available cash, our Partnership Agreement, including the provisions requiring us to distribute all of our available cash, may be amended. We can amend our Partnership Agreement with the consent of our General Partner and the approval of a majority of the outstanding common units.

- Even if our cash distribution policy is not modified or revoked, the amount of distributions we pay under our cash distribution policy and the decision to make any distribution is determined by our General Partner, taking into consideration the terms of our Partnership Agreement.
- Under Delaware law, we may not make a distribution if the distribution would cause our liabilities to exceed the fair value of our assets.
- We may lack sufficient cash to pay distributions to our unitholders due to cash flow shortfalls attributable to a number of operational, commercial or other factors as well as increases in our operating or general and administrative expenses, principal and interest payments on our debt, tax expenses, working capital requirements and anticipated cash needs. Our cash available for distribution to unitholders is directly impacted by our cash expenses necessary to run our business and will be reduced dollar-for-dollar to the extent such uses of cash increase.
- If and to the extent our cash available for distribution materially declines, we may elect to reduce our quarterly distribution rate to service or repay our debt or fund expansion capital expenditures.

Preferred Unit Distributions

Series A Preferred Units

In November 2017, we issued 300,000 Series A Preferred Units at a price to the public of $1,000 per Series A Preferred Unit.

During the year ended December 31, 2021, we exchanged 18,662 Series A Preferred Units for 538,715 SMLP common units, net of units withheld for withholding taxes (the “2021 Preferred Exchange Offer”). As of December 31, 2021, we had 143,447 Series A Preferred Units outstanding and $29.9 million of accrued and unpaid distributions on our Series A Preferred Units.

In December 2021, we commenced an exchange offer that settled in January 2022 (the “2022 Preferred Exchange Offer” and together with the 2021 Preferred Exchange Offers, the “Preferred Exchange Offers”) whereby we exchanged 77,939 Series A Preferred Units for 2,853,875 SMLP common units, net of units withheld for withholding taxes. As of January 31, 2022, we had 65,508 Series A Preferred Units outstanding and $14.3 million of accrued and unpaid distributions on our Series A Preferred Units.

In May 2020, in connection with the GP Buy-In Transaction, the Partnership suspended payments of distributions to holders of its Series A Preferred Units, and we did not make a distribution on our Series A Preferred Units in 2021 or 2020.

Distributions on the Series A Preferred Units are cumulative and compounding and are payable semi-annually in arrears on the 15th day of each June and December through and including December 15, 2022, and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year (each, a “Distribution Payment Date”) to holders of record as of the close of business on the first business day of the month of the applicable Distribution Payment Date, in each case, when, as, and if declared by the General Partner out of legally available funds for such purpose.

The initial distribution rate for the Series A Preferred Units is 9.50% per annum of the $1,000 liquidation preference per Series A Preferred Unit. On and after December 15, 2022, distributions on the Series A Preferred Units will accumulate for each distribution period at a percentage of the liquidation preference equal to the three-month LIBOR plus a spread of 7.43%. See Note 12 - Partners' Capital and Mezzanine Capital to the consolidated financial statements for additional details.

Subsidiary Series A Preferred Units

In December 2019 and during the year ended December 31, 2020, Permian Holdco issued 30,057 and 55,251 Subsidiary Series A Preferred Units, respectively, representing limited partner interests in Permian Holdco at a price of $1,000 per unit. As of December 31, 2021, we have 91,439 Subsidiary Series A Preferred Units outstanding.

During the years ended December 31, 2021 and 2020, we elected to make PIK distributions and issued 6,131 and 5,251 Subsidiary Series A Preferred Units, respectively, to the holders of the Subsidiary Series A Preferred Units.

Distributions on the Subsidiary Series A Preferred Units are cumulative and compounding and are payable quarterly in arrears 21 days after the quarter ending March, June, September and December of each year (each, a “Subsidiary Series A Preferred Distribution Payment Date”) to holders of record as of the close of business on the first business day of the month of the applicable Subsidiary Series A Preferred Distribution Payment Date, in each case, when, as, and if declared by the board of directors of Permian Holdco out of legally available funds for such purpose.

The distribution rate is 7.00% per annum of the $1,000 issue amount per outstanding Permian Holdco Subsidiary Series A Preferred Unit. Permian Holdco has the option to pay this distribution in-kind until the first quarter of 2022, which is the first full quarter following the date the Double E Pipeline was placed in service. See Note 12 - Partners' Capital and Mezzanine Capital to the consolidated financial statements for additional details.

Unregistered Sales of Equity Securities

In April 2021, the Partnership completed the 2021 Preferred Exchange Offer. The Preferred Exchange Offer expired on April 13, 2021, and on April 15, 2021, the Partnership issued 538,715 SMLP common units, net of units withheld for withholding taxes, in exchange for 18,662 Series A Preferred Units. Upon the settlement of the 2021 Preferred Exchange Offer, we eliminated $20.7 million of the Series A Preferred Unit liquidation preference amount, inclusive of accrued distributions due as of the settlement date. The Partnership did not receive any cash proceeds from the 2021 Preferred Exchange Offer.

In January 2022, the Partnership completed the 2022 Preferred Exchange Offer. The 2022 Preferred Exchange Offer expired on January 12, 2022, and on January 14, 2022, the Partnership issued 2,853,875 common units, net of units withheld for withholding taxes, in exchange for 77,939 Series A Preferred Units. Upon the settlement of the 2022 Preferred Exchange Offer, we eliminated $92.6 million of the Series A Preferred Unit liquidation preference amount, inclusive of accrued distributions due as of the settlement date. The Partnership did not receive any cash proceeds from the 2022 Preferred Exchange Offer.

The Partnership relied on Section 3(a)(9) of the Securities Act to exempt the Preferred Exchange Offer from the registration requirements of the Securities Act. Section 3(a)(9) offers exemptions from the registration requirements of the Securities Act for exchange offers in which (i) the issuer of the securities offered is the same as the issuer of the securities being surrendered, (ii) the holders are not being asked to surrender anything of value other than the outstanding securities, (iii) the exchange offer is made exclusively to existing holders of the issuer's outstanding securities, and (iv) the issuer does not pay any commission or remuneration for solicitation of the exchange. Because the Partnership offered only its own common units exclusively to the holders of and in exchange for its outstanding Series A Preferred Units, and because it neither paid nor received anything of value other than the subject securities, the Partnership was able to rely on the exemption afforded by Section 3(a)(9) of the Securities Act.

Issuer Purchases of Equity Securities

We made no repurchases of our common units during the quarter or year ended December 31, 2021.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

MD&A is intended to inform the reader about matters affecting the financial condition and results of operations of the Partnership and its subsidiaries. As a result, the following discussion for the year ended December 31, 2021 should be read in conjunction with the consolidated financial statements and notes thereto included in this Annual Report. Among other things, the consolidated financial statements and the related notes include more detailed information regarding the basis of presentation for the following information. This discussion contains forward-looking statements that constitute our plans, estimates and beliefs. These forward-looking statements involve numerous risks and uncertainties, including, but not limited to, those discussed in Forward-Looking Statements. Actual results may differ materially from those contained in any forward-looking statements.

Overview

We are a value-driven limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in unconventional resource basins, primarily shale formations, in the continental United States.

Our financial results are driven primarily by volume throughput across our gathering systems and by expense management. We generate the majority of our revenues from the gathering, compression, treating and processing services that we provide to our customers. A majority of the volumes that we gather, compress, treat and/or process have a fixed-fee rate structure which enhances the stability of our cash flows by providing a revenue stream that is not subject to direct commodity price risk. We also earn a portion of our revenues from the following activities that directly expose us to fluctuations in commodity prices: (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds or other processing arrangements with certain of our customers in the Rockies, Piceance, and Permian segments, (ii) the sale of natural gas we retain from certain Barnett segment customers, (iii) the sale of condensate we retain from our gathering services in the Piceance segment and (iv) additional gathering fees that are tied to the performance of certain commodity price indexes that which are then added to the fixed gathering rates. During the year ended December 31, 2021, these additional activities accounted for approximately 22% of our total revenues.

We also have indirect exposure to changes in commodity prices in that persistently low commodity prices may cause our customers to delay and/or cancel drilling and/or completion activities or temporarily shut-in production, which would reduce the volumes of natural gas and crude oil (and associated volumes of produced water) that we gather. If certain of our customers cancel or delay drilling and/or completion activities or temporarily shut-in production, the associated MVCs, if any, ensure that we will earn a minimum amount of revenue.

The following table presents certain consolidated and reportable segment financial data. For additional information on our reportable segments, see the "Segment Overview for the Years Ended December 31, 2021 and 2020" section herein.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Net income (loss)	$ (19,949)	$ 189,078
Reportable segment adjusted EBITDA		
Northeast	$ 83,287	$ 85,854
Rockies	64,517	71,509
Permian	6,614	5,744
Piceance	76,131	88,820
Barnett	36,729	32,093
Net cash provided by operating activities	$ 165,099	$ 198,589
Capital expenditures[(1)]	25,030	43,128
Investment in Double E equity method investee	148,699	99,927
Borrowings under ABL Facility	300,000	—
Repayments of ABL Facility	(33,000)	—
Repayments of 2022 Senior Notes	(234,047)	—
Issuance of 2026 Secured Notes	689,500	—
Borrowings under Revolving Credit Facility	—	249,300
Repayments on Revolving Credit Facility	(857,000)	(69,300)
Repayments on SMPH Term Loan	—	(6,300)
Borrowings under Permian Transmission Credit Facility	160,000	—
Open Market Repurchases	—	(145,567)
Debt Tender Offers	—	(47,530)
TL Restructuring	—	(26,500)
Proceeds from issuance of Subsidiary Series A Preferred Units, net of issuance costs	—	48,710
Preferred Tender Offer	—	(25,000)
Purchase of common units in GP Buy-In Transaction	—	(41,778)

(1) See "Liquidity and Capital Resources" herein and Note 18 - Segment Information to the consolidated financial statements for additional information on capital expenditures.

Key Matters for the Year ended December 31, 2021. The following items are reflected in our financial results for the fiscal year ended December 31, 2021:

- ***Refinancing debt obligations with near-term maturities.*** On November 2, 2021, the Co-Issuers issued $700.0 million of the 2026 Secured Notes. We used the net proceeds from the offering of the 2026 Secured Notes, together with cash on hand and borrowings under the ABL Facility, to repay in full all of Summit Holdings' obligations under the Revolving Credit Facility. Additionally, the Co-Issuers redeemed all of the outstanding 2022 Senior Notes at a redemption price equal to 100.0% of the principal amount plus accrued and unpaid interest.
- ***Global Settlement.*** As previously disclosed, we were the subject of multiple investigations stemming from the 2015 Blacktail Release. On August 4, 2021, we entered into a Global Settlement to resolve these legal matters that includes the payment of penalties and fines of $36.3 million over six years. As a result of the settlement, we recognized an additional loss for this matter during 2021 and had $33.2 million accrued for this matter as of December 31, 2021. See Note 10 - Commitments and Contingencies to the consolidated financial statements and Item 3. Legal Proceedings for additional information.
- ***April 2021 Series A Preferred Unit Exchange.*** In April 2021, the Partnership completed the 2021 Preferred Exchange Offer, whereby it issued 538,715 common units, net of units withheld for withholding taxes, in exchange for 18,662 Series A Preferred Units. Upon settlement of the 2021 Preferred Exchange Offer, the Partnership eliminated $20.7 million of the Series A Preferred Unit liquidation preference amount, inclusive of $2.5 million of accrued distributions due as of the settlement date. See Note 12 – Partners' Capital and Mezzanine Capital for additional information.
- ***Double E Project.*** In November 2021, the Partnership placed the Double E Pipeline in service and began recognizing revenue. As a result, our investment in Double E recognized positive equity in earnings from Double E beginning in the quarter ended December 31, 2021. Capital contributions to Double E in 2021 totaled $148.7 million and were funded primarily from our new Permian Transmission Credit Facility and cash on hand.
- ***Loss on ECP Warrants.*** On August 5, 2021, the ECP Entities cashlessly exercised all of their ECP Warrants for an aggregate of 414,447 SMLP common units, net of the exercise price, as calculated pursuant to Section 3(c) of the ECP Warrants (the "ECP Warrant Exercise"). During the year ended December 31, 2021, the Partnership recognized a $13.6 million non-cash loss related to the ECP Warrants.

In addition, in January 2022, the Partnership completed the 2022 Preferred Exchange Offer, whereby it issued 2,853,875 SMLP common units, net of units withheld for withholding taxes, in exchange for 77,939 Series A Preferred Units. Upon settlement of the 2022 Preferred Exchange Offer, the Partnership eliminated $92.6 million of the Series A Preferred Unit liquidation preference amount, inclusive of accrued distributions due as of the settlement date.

Key Matters for the Year ended December 31, 2020. The following items are reflected in our financial results for the fiscal year ended 2020:

- ***GP Buy-In Transaction.*** In May 2020, the Partnership completed the GP Buy-In Transaction whereby the Partnership acquired from its then private equity sponsor, ECP, (i) Summit Investments, which indirectly owned the Partnership's General Partner, (ii) through its ownership of SMP Holdings, 3,415,646 of its common units and (iii) a deferred purchase price obligation receivable owed by the Partnership. Consideration paid to ECP included a $35.0 million cash payment and warrants to purchase up to 666,667 common units. In connection with the closing of the GP Buy-In Transaction, ECP's management resigned from the Board of Directors and fully exited its investment in the Partnership (other than retaining the aforementioned warrants). Refer to Note 1 – Organization, Business Operations and Presentation and Consolidation for details.
- ***Suspension of common and preferred unit distributions.*** In May 2020, and in conjunction with the GP Buy-In Transaction, the Partnership suspended distributions to holders of its common units and its Series A Preferred Units, commencing with respect to the quarter ending March 31, 2020. The suspension of distributions enabled the Partnership to retain an incremental $76.0 million per annum of operating cash flow and reallocate this retained cash to indebtedness reduction, liability management transactions and other corporate initiatives. The unpaid cash distributions on the Series A Preferred Units continue to accrue semi-annually, until paid.

- ***July 2020 Series A Preferred Unit Exchang*e**. In July 2020, the Partnership completed an offer to exchange its Series A Preferred Units for newly issued common units (the “2020 Preferred Exchange Offer”), whereby it issued 837,547 common units in exchange for 62,816 Series A Preferred Units. Upon closing the 2020 Preferred Exchange Offer, it eliminated $66.5 million of the Series A Preferred Unit liquidation preference amount, inclusive of $3.7 million of accrued distributions due as of the settlement date.
- ***Open Market Repurchase of Senior Notes.*** Throughout 2020, the Partnership completed multiple open market repurchases of the 2022 Senior Notes and the 2025 Senior Notes (the “Open Market Repurchases”), which resulted in the extinguishment of $32.4 million of face value of the 2022 Senior Notes and $201.8 million of face value of the 2025 Senior Notes. Total cash consideration paid to repurchase the principal amounts outstanding of the 2022 Senior Notes and 2025 Senior Notes, plus accrued interest totaled $150.3 million and the Partnership recognized an $86.4 million gain on the extinguishment of debt related to these Open Market Repurchases during 2020.
- ***Debt Tender Offers.*** In September 2020, the Co-Issuers completed the cash tender offers (the “Debt Tender Offers”) to purchase a portion of their 2022 Senior Notes and 2025 Senior Notes. Upon completion of the Debt Tender Offers, the Co-Issuers repurchased $33.5 million principal amount of the 2022 Senior Notes and $38.7 million principal amount of the 2025 Senior Notes. Total cash consideration paid to repurchase the principal amounts outstanding of the 2022 and 2025 Senior Notes, plus accrued interest, totaled $48.7 million, and the Partnership recognized a $23.3 million gain on the extinguishment of debt related to the Debt Tender Offers during 2020.
- ***TL Restructuring.*** In November 2020, the Partnership completed the consensual debt discharge and restructuring (the “TL Restructuring”) of SMP Holdings’ $155.2 million term loan (the “SMPH Term Loan”). As part of the TL Restructuring, the Partnership paid SMP Holdings $26.5 million in cash as consideration to fully settle the deferred purchase price obligation, which SMP Holdings then paid to the lenders under the SMPH Term Loan (the “Term Loan Lenders”). In addition, the Term Loan Lenders executed a strict foreclosure on the 2,306,972 common units pledged as collateral under the SMPH Term Loan in full satisfaction of SMP Holdings’ outstanding obligations under the SMPH Term Loan.
- ***December 2020 Series A Preferred Unit Tender.*** On December 29, 2020, the Partnership completed a cash tender offer for its Series A Preferred Units (the “Preferred Tender Offer”), whereby it accepted 75,075 Series A Preferred Units for a purchase price of $333.00 per Series A Preferred Unit and an aggregate purchase price of $25.0 million. Upon closing the Preferred Tender Offer, it eliminated $82.7 million of the Series A Preferred Unit liquidation preference due as of the settlement date, inclusive of $7.6 million of accrued distributions.
- ***Double E Project.*** For the year ended December 2020, the Partnership’s proportionate share of capital calls due in 2020 totaled $99.9 million, which includes $2.7 million in capitalized interest, and was funded with $20.6 million of Partnership generated funds and the issuance of $85.3 million of Subsidiary Series A Preferred Units.
- ***2020 Restructuring Costs.*** In the fourth quarter of 2020, we completed an internal initiative to evaluate and transform our cost structure, enhance margins and improve our competitive position in response to COVID-19 and the related weakening of the economy. For the year ended December 31, 2020, we incurred approximately $5.6 million in restructuring costs relating to this initiative (included in general and administrative expense).

Trends and Outlook

Our business has been, and we expect our future business to continue to be, affected by the following key trends:

- Ongoing impact of the COVID-19 pandemic and fluctuations in demand for oil and natural gas;
- Natural gas, NGL and crude oil supply and demand dynamics;
- Production from U.S. shale plays;
- Capital markets availability and cost of capital; and
- Inflation and shifts in operating costs.

Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Ongoing impact of the COVID-19 pandemic and fluctuations in demand for oil and natural gas. We continue to closely monitor the impact of the COVID-19 pandemic, including its variants, on all aspects of our business, including how it has impacted and will impact our customers, employees, supply chain and distribution network. We are unable to predict the ultimate impact that COVID-19, its variants and related factors may have on our business, future results of operations, financial position or cash flows. Given the dynamic nature of the COVID-19 pandemic and related market conditions, we cannot reasonably estimate the period of time that these events will persist or the full extent of the impact they will have on our business. The extent to which our operations may be impacted by the COVID-19 pandemic will depend largely on future developments, which are highly uncertain and cannot be accurately predicted, including changes in the severity of the pandemic, countermeasures taken by governments, businesses and individuals to slow the spread of the pandemic, and the development and availability of treatments and the extent to which these treatments and vaccines may remain effective as potential new strains of the coronavirus emerge. Furthermore, the impacts of a potential worsening of global economic conditions and the continued disruptions to and volatility in the financial markets remain unknown.

In response to the COVID-19 pandemic, we have modified our business practices, including restricting employee travel, utilizing COVID-19 pandemic tax relief (as allowed by the ERC Tax Credit), modifying employee work locations, implementing social distancing and enhancing sanitary measures in our facilities. Many of our suppliers, vendors and service providers have made similar modifications. Our increased reliance on remote access to our information systems increases our exposure to potential cybersecurity breaches. We may take further actions as government authorities require or recommend or as we determine to be in the best interests of our employees, customers, partners and suppliers.

In addition, as a result of the COVID-19 pandemic, we experienced oil and natural gas price volatility during 2021, largely due to supply and demand imbalances resulting from lower development activity decisions by our customers, actions by members of OPEC and other foreign, oil-exporting countries. This disrupted the oil and natural gas exploration and production industry and other industries that serve exploration and production companies. These industry conditions, coupled with those resulting from the COVID-19 pandemic, could lead to significant global economic contraction generally and in our industry in particular.

We have collaborated extensively with our customer base regarding impacts to their drilling and completion activities in light of the COVID-19 pandemic. Based on recently updated production forecasts and 2022 development plans from our customers, we currently expect that 2022 activity will be lower than historical periods prior to COVID-19.

Natural gas, NGL and crude oil supply and demand dynamics. Natural gas continues to be a critical component of energy supply and demand in the United States. The average spot price of natural gas increased by approximately 92% from 2020 to 2021, primarily due to natural gas demand exceeding supply. The average daily Henry Hub Natural Gas Spot Price was $3.89 per MMBtu during 2021, compared with $2.03 per MMBtu during 2020. Henry Hub closed at $3.82 per MMBtu on December 31, 2021. As of January 31, 2022, Henry Hub 12-month strip pricing closed at $4.81 per MMBtu. Natural gas prices continue to trade at higher-than-average historical prices due in part to strong power sector demand and relatively modest new production growth. In response to the increasing natural gas prices, the number of active natural gas drilling rigs in the continental United States increased from 83 in December 2020 to 106 in December 2021, but still remains well below the 2017 through 2019 average of 177, according to Baker Hughes. The average amount of working natural gas in underground storage in the continental U.S. was 2.7 Tcfe in 2021, which was 11% lower than in 2020. Over the long term, we believe that the prospects for continued natural gas demand are favorable and will be driven primarily by global population and economic growth, as well as the continued displacement of coal-fired electricity generation by natural gas-fired electricity generation and increase in U.S. LNG exports. Over the next several years, we expect natural gas prices will support continued upstream industry activity by producers focused on natural gas production.

In addition, certain of our gathering systems are directly affected by crude oil supply and demand dynamics. Crude oil prices increased in 2021, with the average daily Cushing, Oklahoma West Texas Intermediate crude oil spot price average of $39.16 per barrel during 2020 to an average of $68.14 per barrel during 2021, representing a 74% increase, reflecting broader market concerns for global oil supply and demand dynamics. In response to the increasing crude oil prices, the number of active crude oil drilling rigs in the continental United States increased from 267 in December 2020 to 480 in December 2021, but still remains well below the 2017 through 2019 average of 773, according to Baker Hughes. Over the next several years, we expect that crude oil prices will support continued drilling activity and increasing production in the Williston Basin, Permian Basin and, given the current regulatory environment in Colorado, in rural parts of the DJ Basin.

Despite improving fundamentals that should support additional development activities, we note that over the last several years there has been an increasing societal opposition to the production of hydrocarbons generally, which may be reflected in legislation, executive orders or regulations that may significantly restrict the domestic production of fossil fuels, including natural gas.

Growth in production from U.S. shale plays. Over the past several years, natural gas production from unconventional shale resources has increased significantly due to advances in technology that allow producers to extract significant volumes of natural gas from unconventional shale plays on favorable economic terms relative to most conventional plays. In recent years, a number of producers and their joint venture partners, including large international operators, industrial manufacturers and private equity sponsors, have committed significant capital to the development of these unconventional resources, including the Piceance, Barnett, Bakken, Marcellus, Utica and Permian Basin shale plays in which we operate. We believe that these long-term capital investments should support drilling activity in unconventional shale plays over the long term.

Rate of growth in production from U.S. shale plays. Some of our producer customers have adjusted their drilling and completion activities and schedules to manage drilling and completion costs at levels that are achievable using internally generated cash flow from their underlying operations. Historically, as part of a strategy to accelerate production growth, these producers would raise external capital to fund drilling and completion costs in excess of the cash flows generated from their underlying assets. Producers are experiencing increasing pressure from their investors to focus on returning capital and maximizing free cash flow versus re investing that cash flow into development. In general, we expect our producer customers to maintain moderate completion and production activities across many of our systems relative to our previous expectations as a result of the commodity price environment and a continuation of the general trend of producers constraining drilling and completion activity to levels that can be satisfied with internally generated cash flow.

Capital markets availability and cost of capital. Capital markets conditions, including but not limited to availability and higher borrowing costs, could affect our ability to access the debt and equity capital markets to the extent necessary, to fund our future growth. Furthermore, market demand for equity issued by master limited partnerships has been significantly lower in recent years than it has been historically, which may make it more challenging for us to finance our capital expenditures with the issuance of additional equity. We announced the elimination of our common unit distribution in May 2020 beginning with the distribution paid in respect of the first quarter of 2020, and this action may further reduce demand for our common units. In addition, interest rates on future credit facilities and debt offerings could be higher than current levels, causing our financing costs to increase accordingly.

Inflation and operating costs. The annual rate of inflation in the United States hit 7.5% in January 2022, the highest in more than three decades, as measured by the Consumer Price Index. We expect that inflation in 2022 will increase our operating costs and the overall cost of capital projects we undertake. While some of our fee arrangements escalate based on changes in price indexes, these fee escalations may not be sufficient to offset an increase in our expenditures. Furthermore, inflation may impact producers economic decision making, which in turn could impact their willingness to develop acreage in areas that are more susceptible to inflationary pressures and labor force shortages.

How We Evaluate Our Operations

We conduct and report our operations in the midstream energy industry through five reportable segments: Northeast, Rockies, Permian, Piceance and Barnett. Each of our reportable segments provides midstream services in a specific geographic area and our reportable segments reflect the way in which we internally report the financial information used to make decisions and allocate resources in connection with our operations (see Note 18 - Segment Information to the consolidated financial statements). Our management uses a variety of financial and operational metrics to analyze our consolidated and segment performance and we view these metrics as important factors in evaluating our profitability. These metrics include (i) throughput volume, (ii) revenues, (iii) operation and maintenance expenses, (iv) capital expenditures and (v) segment adjusted EBITDA.

Throughput Volume

The volume of (i) natural gas that we gather, compress, treat and/or process and (ii) crude oil and produced water that we gather depends on the level of production from natural gas or crude oil wells connected to our gathering systems. Aggregate production volumes are impacted by the overall amount of drilling and completion activity. Furthermore, because the production rate of natural gas and crude oil wells decline over time, production can only be maintained or increased by new drilling or other activity.

As a result, we must continually obtain new supplies of production to maintain or increase the throughput volume on our systems. Our ability to maintain or increase throughput volumes from existing customers and obtain new supplies of throughput is impacted by:

- successful drilling activity within our AMIs;
- the level of work-overs and recompletions of wells on existing pad sites to which our gathering systems are connected;
- the number of new pad sites in our AMIs awaiting connections;
- our ability to compete for volumes from successful new wells in the areas in which we operate outside of our existing AMIs; and
- our ability to gather, treat and/or process production that has been released from commitments with our competitors.

We report volumes gathered for natural gas in cubic feet per day. We aggregate crude oil and produced water gathering and report volumes gathered in barrels per day.

Revenues

Our revenues are primarily attributable to the volumes that we gather, compress, treat and/or process and the rates we charge for those services. A majority of our gathering and processing agreements are fee-based, which limits our direct exposure to fluctuations in commodity prices; however, certain of our contracts have rates that are directly impacted by commodity prices. We also have percent-of-proceeds arrangements with certain customers under which the gathering and processing revenues that we earn correlate directly with the fluctuating price of natural gas, condensate and NGLs.

Certain of our gathering and processing agreements contain MVCs pursuant to which our customers agree to ship or process a minimum volume of production on our gathering systems, or, in some cases, to pay a minimum monetary amount, over certain periods during the term of the MVC. These MVCs help us generate stable revenues and serve to mitigate the financial impact associated with declining volumes.

Operation and Maintenance Expenses

We seek to maximize the profitability of our operations in part by minimizing, to the extent appropriate, expenses directly tied to operating our assets. Direct labor costs, compression costs, ad valorem taxes, repair and non-capitalized maintenance costs, integrity management costs, utilities and contract services comprise the most significant portion of our operation and maintenance expense. Other than utilities expense, these expenses are largely independent of volumes delivered through our gathering systems but may fluctuate depending on the activities performed during a specific period.

Segment Adjusted EBITDA

Segment adjusted EBITDA is a supplemental financial measure used by management and by external users of our financial statements such as investors, commercial banks, research analysts and others.

Segment adjusted EBITDA is used to assess:

- the ability of our assets to generate cash sufficient to make cash distributions and support our indebtedness;
- the financial performance of our assets without regard to financing methods, capital structure or historical cost basis;
- our operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure;
- the attractiveness of capital projects and acquisitions and the overall rates of return on alternative investment opportunities; and
- the financial performance of our assets without regard to (i) income or loss from equity method investees, (ii) the impact of the timing of MVC shortfall payments under our gathering agreements or (iii) the timing of impairments or other noncash income or expense items.

Additional Information. For additional information, see the “Results of Operations” section herein and the notes to the consolidated financial statements.

Results of Operations

Consolidated Overview for the Years Ended December 31, 2021 and 2020

The following table presents certain consolidated data and volume throughput for the years ended December 31, 2021 and 2020.

	Year ended December 31, 2021	Year ended December 31, 2020	Percentage change
	(In thousands)		
Revenues:			
Gathering services and related fees	$ 281,705	$ 302,792	(7%)
Natural gas, NGLs and condensate sales	82,768	49,319	68%
Other revenues	36,145	31,362	15%
Total revenues	400,618	383,473	4%
Costs and expenses:			
Cost of natural gas and NGLs	81,969	36,653	124%
Operation and maintenance	74,178	86,030	(14%)
General and administrative	58,166	73,438	(21%)
Depreciation and amortization	119,076	118,132	1%
Transaction costs	1,677	2,993	(44%)
Gain on asset sales, net	(369)	(307)	20%
Long-lived asset impairment	10,151	13,089	(22%)
Total costs and expenses	344,848	330,028	4%
Other income (expense), net	(613)	48	*
Loss on ECP Warrants	(13,634)	—	N/A
Interest expense	(66,156)	(78,894)	(16%)
Gain (loss) on early extinguishment of debt	(3,523)	203,062	*
Income (loss) before income taxes and equity method investment income	(28,156)	177,661	*
Income tax benefit	327	146	*
Income from equity method investees	7,880	11,271	*
Net income (loss)	$ (19,949)	$ 189,078	*
Volume throughput [(1)]:			
Aggregate average daily throughput - natural gas (MMcf/d)	1,356	1,375	(1%)
Aggregate average daily throughput - liquids (Mbbl/d)	63	79	(20%)

* Not considered meaningful

(1) Excludes volume throughput for Ohio Gathering and Double E. For additional information, see the Northeast and Permian sections herein under the caption "Segment Overview for the Years Ended December 31, 2021 and 2020".

Volumes – Gas. Natural gas throughput volumes decreased 19 MMcf/d for the year ended December 31, 2021 compared to the year ended December 31, 2020, primarily reflecting:

- a volume throughput increase of 39 MMcf/d for the Northeast segment.
- a volume throughput decrease of 38 MMcf/d for the Piceance segment.
- a volume throughput decrease of 7 MMcf/d for the Permian segment.
- a volume throughput decrease of 8 MMcf/d for the Barnett segment.
- a volume throughput decrease of 5 MMcf/d for the Rockies segment.

Volumes – Liquids. Crude oil and produced water volume throughput for the Rockies segment decreased 16 Mbbl/d for the year ended December 31, 2021 compared to the year ended December 31, 2020.

For additional information on volumes, see the "Segment Overview for the Years Ended December 31, 2021 and 2020" section herein.

Revenues. Total revenues increased $17.1 million during the year ended December 31, 2021 compared to the year ended December 31, 2020, comprised of a $33.4 million increase in natural gas, NGLs and condensate sales and a $4.8 million increase in Other revenues, offset by a $21.1 million decrease in gathering services and related fees.

Gathering services and related fees. Gathering services and related fees decreased $21.1 million compared to the year ended December 31, 2020, primarily reflecting:

- a $11.4 million decrease in gathering services and related fees in the Piceance, primarily due to lower volume throughput due to a lack of drilling and completion activity and natural production declines; and
- an $8.3 million decrease in gathering services and related fees in the Rockies, primarily due to lower volume throughput as a result of limited drilling and completion activity that was insufficient to offset natural production declines.

Natural Gas, NGLs and Condensate Sales. Natural gas, NGLs and condensate sales revenue increased $33.4 million compared to the year ended December 31, 2020, primarily reflecting:

- a $28.0 million increase in the Rockies reportable segment;
- a $9.9 million increase in the Permian reportable segment; and
- a $2.9 million increase in the Piceance reportable segment; partially offset by
- a $7.3 million decrease in the Barnett reportable segment.

Costs and expenses. Total costs and expenses increased $14.8 million during the year ended December 31, 2021 compared to the year ended December 31, 2020, primarily reflecting:

Cost of natural gas and NGLs. Cost of natural gas and NGLs increased $45.3 million during the year ended December 31, 2021 compared to the year ended December 31, 2020, primarily driven by higher natural gas, NGL and crude oil prices.

Operation and maintenance. Operation and maintenance expense decreased $11.9 million for the year ended December 31, 2021 compared to the year ended December 31, 2020; primarily driven by reduced employee headcount as a result of restructuring activities implemented in the fourth quarter of 2020. The Partnership realized $10.2 million of benefits during the year ended December 31, 2021, that are not otherwise expected to occur in 2022 and future periods, as a result of commercial settlements and the ERC Tax Credit.

General and Administrative. General and administrative expense decreased $15.3 million for the year ended December 31, 2021 compared to the year ended December 31, 2020, primarily due to a decrease in salaries and benefits associated with lower headcount from our workforce restructuring in late 2020 (the "2020 Restructuring Plan") and lower legal expenses. General and administrative expense includes a loss related to the 2015 Blacktail Release of $22.4 million and $17.0 million during the fiscal years ended December 31, 2021 and 2020, respectively (see Note 10 - Commitments and Contingencies for additional information).

The Partnership realized $1.0 million of ERC Tax Credit benefits during the year ended December 31, 2021, that are not otherwise expected to occur in future periods.

Loss on ECP Warrants. On August 5, 2021, the ECP Entities cashlessly exercised all of its ECP Warrants for an aggregate of 414,447 SMLP common units, net of the exercise price. During the year ended December 31, 2021, the Partnership recognized a $13.6 million non-cash loss related to the ECP Warrants.

Interest Expense. The decrease in interest expense in the year ended December 31, 2021 compared to the year ended December 31, 2020, was primarily due to lower debt balances as a result of our liability management initiatives completed during 2020 which included (i) the Open Market Repurchases, (ii) the Debt Tender Offers, and (iii) the TL Restructuring. The decrease in interest expense was partially offset by borrowings on the Permian Transmission Credit Facility and higher interest costs resulting from the issuance of the 2026 Secured Notes.

Gain on early extinguishment of debt. The $203.1 million gain on the early extinguishment of debt for the year ended December 31, 2020 is primarily related to liability management initiatives undertaken during 2020 that resulted in a $86.4 million gain from the Open Market Repurchases, a $23.3 million gain from the Debt Tender Offers, and a $93.9 million gain from our TL Restructuring. Further details of our liability management results are summarized below.

	ECP Loan Repayment	Open Market Repurchases		Tender Offers		TL Restructuring	Total
		2022 Senior Notes	2025 Senior Notes	2022 Senior Notes	2025 Senior Notes		
				(in thousands)			
Gain on Repurchases of Senior Notes and TL Restructuring	$ —	$ 11,554	$ 76,789	$ 9,223	$ 15,479	$ 99,175	$ 212,220
Debt issue costs	(361)	(143)	(1,541)	(125)	(351)	(2,724)	(5,245)
Transaction cost	(249)	(105)	(105)	(467)	(467)	(2,520)	(3,913)
Gain (loss) on debt extinguishment	$ (610)	$ 11,306	$ 75,143	$ 8,631	$ 14,661	$ 93,931	$ 203,062

Segment Overview for the Years Ended December 31, 2021 and 2020

Northeast.

Volume throughput for the Northeast reportable segment follows.

	Northeast		
	Year ended December 31,		
	2021	2020	Percentage Change
Average daily throughput (MMcf/d)	765	726	5%
Average daily throughput (MMcf/d) (Ohio Gathering)	526	571	(8)%

Volume throughput for the Northeast, excluding Ohio Gathering, increased 5% compared to the year ended December 31, 2020 primarily due to 35 new well connections, partially offset by natural production declines from existing wells.

Volume throughput for the Ohio Gathering system decreased 8% compared to the year ended December 31, 2020, primarily as a result of natural production declines on existing wells on the system, partially offset by 17 new well connections.

Financial data for our Northeast reportable segment follows.

	Northeast		
	Year ended December 31,		
	2021	2020	Percentage Change
Revenues:	(Dollars in thousands)		
Gathering services and related fees	$ 62,567	$ 62,250	1%
Total revenues	62,567	62,250	1%
Costs and expenses:			
Operation and maintenance	5,672	6,739	(16%)
General and administrative	599	646	(7)%
Depreciation and amortization	17,054	16,891	1%
Gain on asset sales, net	(92)	(43)	114%
Long-lived asset impairment	130	—	N/A
Total costs and expenses	23,363	24,233	(4%)
Add:			
Depreciation and amortization	17,054	16,891	
Adjustments related to capital reimbursement activity	(83)	(67)	
Gain on asset sales, net	(92)	(43)	
Long-lived asset impairment	130	—	
Proportional adjusted EBITDA for Ohio Gathering	27,074	31,056	
Segment adjusted EBITDA	$ 83,287	$ 85,854	(3%)

* Not considered meaningful

Year ended December 31, 2021. Segment adjusted EBITDA decreased $2.6 million compared to the year ended December 31, 2020, primarily due to a $4.0 million decrease in proportional adjusted EBITDA for Ohio Gathering as a result of lower volume throughput, partially offset by a $1.1 million decrease in operation and maintenance costs.

Rockies.

Volume throughput for our Rockies reportable segment follows.

	Rockies		
	Year ended December 31,		
	2021	2020	Percentage Change
Aggregate average daily throughput - natural gas (MMcf/d)	35	40	(13)%
Aggregate average daily throughput - liquids (Mbbl/d)	63	79	(20)%

Natural gas. Natural gas volume throughput in 2021 decreased 13% compared to the year ended December 31, 2020, primarily reflecting natural production declines, partially offset by 3 new well connections in 2021.

Liquids. Liquids volume throughput in 2021 decreased 20% compared to the year ended December 31, 2020, primarily associated with natural production declines, partially offset by 22 wells that were commissioned in 2021, of which 16 wells were connected in the fourth quarter.

Financial data for our Rockies reportable segment follows.

	Rockies		
	Year ended December 31,		
	2021	2020	Percentage Change
	(Dollars in thousands)		
Revenues:			
Gathering services and related fees	$ 74,823	$ 83,107	(10%)
Natural gas, NGLs and condensate sales	48,279	20,263	138%
Other revenues	21,985	17,395	26%
Total revenues	145,087	120,765	20%
Costs and expenses:			
Cost of natural gas and NGLs	47,984	12,808	275%
Operation and maintenance	29,251	33,372	(12%)
General and administrative	1,506	2,826	(47%)
Depreciation and amortization	29,513	32,057	(8%)
Gain on asset sales, net	(56)	(30)	87%
Long-lived asset impairment	5,564	6,113	(9%)
Total costs and expenses	113,762	87,146	31%
Add:			
Depreciation and amortization	29,513	32,057	
Adjustments related to capital reimbursement activity	(1,885)	(250)	
Gain on asset sales, net	(56)	(30)	
Long-lived asset impairment	5,564	6,113	
Other	56	—	
Segment adjusted EBITDA	$ 64,517	$ 71,509	(10%)

* Not considered meaningful

Year ended December 31, 2021. Segment adjusted EBITDA decreased $7.0 million compared to the year ended December 31, 2020 primarily associated with the decreased liquid and natural gas volume throughput described above and its associated decrease in gathering services and related fees of $8.3 million. The decrease was partially offset by the decrease in operation and maintenance expense of $4.1 million and the decrease in general and administrative expense of $1.3 million, primarily due to our 2020 Restructuring Plan, cost-saving initiatives and lower general operating expenses.

Permian.

Volume throughput for our Permian reportable segment follows.

	Permian		
	Year ended December 31,		
	2021	2020	Percentage Change
Average daily throughput (MMcf/d)	26	33	(21%)
Average daily throughput (MMcf/d) (Double E)	124	n/a	n/a

Volume throughput in 2021, excluding Double E, decreased 21% compared to the year ended December 31, 2020, primarily as a result of natural production declines, partially offset by 2 new connections during the year.

Double E commenced operations during November 2021 and averaged 124 MMcf per day for the period from the date of commencement in November 2021 through December 31, 2021.

Financial data for our Permian reportable segment follows.

	Permian		
	Year ended December 31,		
	2021	2020	Percentage Change
	(Dollars in thousands)		
Revenues:			
Gathering services and related fees	$ 8,230	$ 10,091	(18%)
Natural gas, NGLs and condensate sales	28,727	18,857	52%
Other revenues	3,891	3,161	23%
Total revenues	40,848	32,109	27%
Costs and expenses:			
Cost of natural gas and NGLs	29,855	18,785	59%
Operation and maintenance	5,585	6,038	(8%)
General and administrative	757	1,542	(51%)
Depreciation and amortization	5,858	5,455	7%
Long-lived asset impairment	595	324	84%
Total costs and expenses	42,650	32,144	33%
Add:			
Depreciation and amortization	5,858	5,455	
Long-lived asset impairment	595	324	
Proportional adjusted EBITDA for Double E	1,948	—	
Other	15	—	
Segment adjusted EBITDA	$ 6,614	$ 5,744	*

* Not considered meaningful

Year ended December 31, 2021. Segment adjusted EBITDA increased $0.9 million compared to the year ended December 31, 2020 primarily as a result of a $1.9 million increase in our proportionate adjusted EBITDA associated with the commencement of commercial operations of Double E in November 2021.

Piceance.

Volume throughput for our Piceance reportable segment follows.

	Piceance		
	Year ended December 31,		
	2021	2020	Percentage Change
Aggregate average daily throughput (MMcf/d)	326	364	(10%)

Volume throughput decreased 10% in 2021 compared to the year ended December 31, 2020, as a result of natural production declines, partially offset by 9 new well connections in the fourth quarter of 2021.

Financial data for our Piceance reportable segment follows.

	Piceance		
	Year ended December 31,		
	2021	2020	Percentage Change
	(Dollars in thousands)		
Revenues:			
Gathering services and related fees	$ 95,235	$ 106,657	(11%)
Natural gas, NGLs and condensate sales	5,464	2,612	109%
Other revenues	4,786	4,621	4%
Total revenues	105,485	113,890	(7%)
Costs and expenses:			
Cost of natural gas and NGLs	3,823	1,717	123%
Operation and maintenance	21,664	21,064	3%
General and administrative	1,163	1,053	10%
Depreciation and amortization	48,773	45,203	8%
(Gain) loss on asset sales, net	(119)	(190)	(37%)
Long-lived asset impairment	3,239	7	*
Total costs and expenses	78,543	68,854	14%
Add:			
Depreciation and amortization	48,773	45,203	
Adjustments related to capital reimbursement activity	(3,271)	(1,236)	
(Gain) loss on asset sales, net	(119)	(190)	
Long-lived asset impairment	3,239	7	
Other	567	—	
Segment adjusted EBITDA	$ 76,131	$ 88,820	(14%)

* Not considered meaningful

Year ended December 31, 2021. Segment adjusted EBITDA decreased $12.7 million compared to the year ended December 31, 2020, primarily associated with the volume throughput decrease described above and a $3.3 million decrease in shortfall payments from an MVC that expired during the third quarter of 2021, and a $1.9 million contractual decrease in demand payments from a certain customer beginning in the third quarter of 2021.

Barnett.

Volume throughput for our Barnett reportable segment follows.

	Barnett		
	Year ended December 31,		
	2021	2020	Percentage Change
Average daily throughput (MMcf/d)	204	212	(4%)

Volume throughput decreased 4% in 2021 compared to the year ended December 31, 2020 reflecting natural production declines partially offset by 7 wells that were commissioned in the third quarter of 2021.

Financial data for our Barnett reportable segment follows.

	Barnett		
	Year ended December 31,		
	2021	2020	Percentage Change
	(Dollars in thousands)		
Revenues:			
Gathering services and related fees	$ 40,850	$ 40,687	0%
Natural gas, NGLs and condensate sales	298	7,587	(96%)
Other revenues [(1)]	5,443	6,185	(12%)
Total revenues	46,591	54,459	(14%)
Costs and expenses:			
Cost of natural gas and NGLs	—	3,341	(100%)
Operation and maintenance	8,497	18,814	(55%)
General and administrative	972	1,306	(26%)
Depreciation and amortization	15,195	15,174	0%
Gain on asset sales, net	(101)	(19)	432%
Long-lived asset impairment	622	4,902	(87%)
Total costs and expenses	25,185	43,518	(42%)
Add:			
Depreciation and amortization [(1)]	16,133	16,112	
Adjustments related to capital reimbursement activity	(1,331)	157	
Gain on asset sales, net	(101)	(19)	
Long-lived asset impairment	622	4,902	
Segment adjusted EBITDA	$ 36,729	$ 32,093	14%

*Not considered meaningful
[(1)] Includes the amortization expense associated with our favorable and unfavorable gas gathering contracts as reported in other revenues.

Year ended December 31, 2021. Segment adjusted EBITDA increased $4.6 million compared to the year ended December 31, 2020 primarily as a result of lower operating expenses, namely resulting from commercial settlements, offset by lower volume throughput.

Corporate and Other Overview for the Years Ended December 31, 2021 and 2020

Corporate and Other represents those results that are not specifically attributable to a reportable segment or that have not been allocated to our reportable segments, including certain general and administrative expense items, natural gas and crude oil marketing services, construction management fees related to the Double E Project, transaction costs, interest expense and gains on early extinguishment of debt.

	Corporate and Other		
	Year ended December 31,		Percentage Change
	2021	2020	
	(Dollars in thousands)		
Revenues:			
Total revenues	$ 40	$ —	*
Costs and expenses:			
General and administrative	53,169	66,934	(21%)
Transaction costs	1,677	2,993	(44%)
Interest expense	66,156	78,894	(16%)
Gain on asset sales or disposals	—	(21)	*
Long-lived asset impairment	—	1,740	*
Gain on early extinguishment of debt	(3,523)	(203,062)	*

* Not considered meaningful

General and administrative. General and administrative expense attributable to Corporate and Other decreased by $13.8 million compared to the year ended December 31, 2020, primarily as a result of increased restructuring and deal costs in 2020, as well as a decrease in salaries and benefits associated with lower headcount from our 2020 Restructuring Plan and other cost-cutting initiatives. General and administrative expense includes a loss related to the 2015 Blacktail Release of $22.4 million and $17.0 million during the fiscal years ended December 31, 2021 and 2020, respectively (see Note 10 - Commitments and Contingencies for additional information).

Interest Expense. Interest expense decreased $12.7 million compared to the year ended December 31, 2020 primarily due to lower debt balances as a result of our liability management initiatives completed during 2020 which included (i) the Open Market Repurchases, (ii) the Debt Tender Offers, and (iii) the TL Restructuring. The decrease in interest expense was partially offset by borrowings on the Permian Transmission Credit Facility and higher interest costs resulting from the issuance of the 2026 Secured Notes.

Gain on Early Extinguishment of Debt. The gain on the early extinguishment of debt for the year ended December 31, 2020 is primarily related to liability management initiatives undertaken during 2020 that resulted in a $86.4 million gain from the Open Market Repurchases, a $23.3 million gain from the Debt Tender Offers, and a $93.9 million gain from our TL Restructuring.

Liquidity and Capital Resources

We rely primarily on internally generated cash flow as well as external financing sources, including our ABL Facility and the issuance of debt, equity and preferred equity securities, and proceeds from potential asset divestitures to fund our capital expenditures. We believe that our ABL Facility and Permian Transmission Credit Facility, together with internally generated cash flow and access to debt or equity capital markets, will be adequate to finance our operations for the next twelve months without adversely impacting our liquidity.

We may enter into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations. As of December 31, 2021, our material off-balance sheet arrangements and transactions include (i) letters of credit outstanding against our ABL Facility aggregating to $23.9 million, and (ii) outstanding surety bonds aggregating to $2.0 million. There are no other transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect our liquidity or availability of our capital resources.

ABL Facility. Summit Holdings has a $400.0 million revolving ABL Facility pursuant to that certain Loan and Security Agreement, dated as of November 2, 2021 (the "ABL Agreement"), with a maturity date of May 1, 2026. The maturity date of the ABL Facility will spring forward to December 13, 2024 if the outstanding amount of the 2025 Senior Notes on such date equals or exceeds $50.0 million or to January 14, 2025 if any amount of the 2025 Senior Notes is outstanding on such date and Liquidity (as defined in the ABL Agreement) is less than the sum of the outstanding principal amount of the 2025 Senior Notes and the Threshold Amount (as defined in the ABL Agreement). As of December 31, 2021, the outstanding balance of the ABL Facility was $267.0 million and the unused commitments were $109.1 million, after giving effect to the issuance thereunder of $23.9 million of outstanding but undrawn irrevocable standby letters of credit. The ABL Facility is secured by a first lien on all of our assets and borrowings are subject to a borrowing base comprised of a percentage of eligible accounts receivable of Summit Holdings and its subsidiaries that guarantee the ABL Facility (collectively, the "ABL Facility Guarantors") and a percentage of eligible above-ground fixed assets including eligible compression units, processing plants, compression stations and related equipment of Summit Holdings and the ABL Facility Guarantors. As of the date of the most recent borrowing base determination, eligible assets totaled $691.2 million, an amount greater than the $400.0 million capacity of the ABL Facility.

There were no defaults or events of default under the ABL Facility during 2021, and as of December 31, 2021, we were in compliance with the financial covenants in the ABL Facility. The ABL Facility requires that Summit Holdings not permit (i) the First Lien Net Leverage Ratio (as defined in the ABL Agreement) as of the last day of any fiscal quarter to be greater than 2.50:1.00, or (ii) the Interest Coverage Ratio (as defined in the ABL Agreement) as of the last day of any fiscal quarter to be less than 2.00:1.00.

The ABL Facility restricts, among other things, Summit Holdings' and its Restricted Subsidiaries' (as defined in the ABL Agreement) ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions or repurchase equity; (iii) make payments on or redeem junior lien, unsecured or subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject both to a number of important exceptions and qualifications.

Permian Transmission Term Loan and Permian Transmission Credit Facility. We have $175.0 million of senior secured credit facilities, which includes a $160.0 million term loan (the "Permian Transmission Term Loan") and a $15.0 million working capital facility (the "Permian Transmission Credit Facility"). As of December 31, 2021, the balance of the Permian Transmission Credit Facility was $160.0 million, and we were in compliance with the financial covenants of the $160.0 million Permian Transmission Credit Facility.

2025 Senior Notes. In February 2017, the Co-Issuers co-issued $500.0 million of 5.75% senior unsecured notes maturing April 15, 2025 (the "2025 Senior Notes"). As of December 31, 2021, the outstanding balance of the 2025 Senior Notes was $259.5 million. The 2025 Senior Notes are senior, unsecured obligations and rank equally in right of payment with all of our existing and future senior obligations. The 2025 Senior Notes are effectively subordinated in right of payment to all of our secured indebtedness, to the extent of the collateral securing such indebtedness. The Co-Issuers may redeem all or part of the 2025 Senior Notes at a redemption price of 102.875% (with the redemption price declining ratably each April 15 to 100.000% on April 15, 2023), plus accrued and unpaid interest, if any, to, but not including, the redemption date.

2026 Secured Notes. In November 2021, we issued $700.0 million of the 2026 Secured Notes, at a price of 98.5% of face value. The Co-Issuers pay interest on the 2026 Secured Notes semi-annually on April 15 and October 15 of each year, commencing on April 15, 2022, and the 2026 Secured Notes are jointly and severally guaranteed, on a senior second-priority secured basis (subject to permitted liens), by us and each of our restricted subsidiaries that is an obligor under the ABL Facility, or under the 2025 Senior Notes on the issue date of the 2026 Secured Notes. As of December 31, 2021, the outstanding balance of the 2026 Secured Notes was $700.0 million.

Starting in the first quarter of 2023 with respect to the fiscal year ended 2022, and continuing annually through the fiscal year ended 2025, the Partnership is required under the terms of the 2026 Secured Notes Indenture to, if it has Excess Cash Flow (as defined in the 2026 Secured Notes Indenture), and subject to its ability to make such an offer under the ABL Credit Facility, offer to purchase an amount of the 2026 Secured Notes, at 100% of the principal amount plus accrued and unpaid interest, equal to 100% of the Excess Cash Flow generated in the prior year. Generally, if the Partnership does not offer to purchase designated annual amounts of its 2026 Secured Notes, or reduce its first lien capacity under the 2026 Secured Notes Indenture per annum from 2023 through 2025, the interest rate on the 2026 Secured Notes is subject to certain rate escalations. Per the terms of the 2026 Secured Notes Indenture, the designated amounts are $50.0 million in aggregate by April 1, 2023, otherwise the interest rate shall automatically increase by 50 basis points per annum; $100.0 million in aggregate by April 1, 2024, otherwise the interest rate shall automatically increase by 100 basis points per annum (minus any amount previously increased); and $200.0 million in aggregate by April 1, 2025, otherwise the interest rate shall automatically increase by 200 basis points per annum (minus any amount previously increased).

To the extent the Partnership makes an offer to purchase, and the offer is not fully accepted by the holders of the 2026 Secured Notes, the Partnership may use any remaining amount not accepted for any purpose not prohibited by the 2026 Secured Notes Indenture, or the ABL Facility.

Double E distribution waterfall. With the commencement of the first flow of gas on the Double E pipeline in November 2021, distributions from Double E will be made monthly starting in the first quarter of 2022. Distributions made to Summit Permian Transmission, LLC will be used to satisfy interest and principal payments required under the Permian Transmission Credit Facility. Any excess cash after these principal and interest payments will then be distributed to Summit Permian Transmission Holdco, LLC to pay the cash distribution due on the Subsidiary Series A Preferred Equity and to redeem portions of the Subsidiary Series A Preferred Units. Currently, we expect Summit Permian Transmission Holdco, LLC will use all of its expected cash receipts in 2022.

Preferred Exchange Offers. In April 2021, we completed the 2021 Preferred Exchange Offer, whereby we exchanged 18,662 Series A Preferred Units for 538,715 newly issued common units, which is net of units withheld for withholding taxes. In January 2022, we completed the 2022 Preferred Exchange Offer, whereby we exchanged 77,939 Series A Preferred Units for 2,853,875 newly issued common units, which is net of units withheld for withholding taxes.

We may in the future use a combination of cash, secured or unsecured borrowings and issuances of our common units or other securities and the proceeds from asset sales to retire or refinance our outstanding debt or Series A Preferred Units through privately negotiated transactions, open market repurchases, redemptions, exchange offers, tender offers or otherwise, but we are under no obligation to do so.

Cash Flows

	Year ended December 31,	
	2021	2020
	(In thousands)	
Net cash provided by operating activities	$ 165,099	$ 198,589
Net cash used in investing activities	(165,729)	(140,569)
Net cash provided by (used in) financing activities	4,658	(79,398)
Net change in cash, cash equivalents and restricted cash	$ 4,028	$ (21,378)

The components of the net change in cash, cash equivalents and restricted cash were as follows:

Operating activities. Details of cash flows from operating activities follow.

Cash flows from operating activities for the year ended December 31, 2021, primarily reflected:

- net loss of $19.9 million plus adjustments of $179.2 million for non-cash items; and
- $5.9 million increase in working capital accounts.

Cash flows from operating activities for the year ended December 31, 2020, primarily reflected:

- net income of $189.1 million plus adjustments of $40.5 million for non-cash items; and
- a $50.0 million increase in working capital.

Investing activities. Details of cash flows from investing activities follow.

Cash flows used in investing activities during the year ended December 31, 2021 primarily reflected:

- $148.7 million of capital contributions and costs for our equity method investment in Double E; and
- $25.0 million of capital expenditures primarily attributable to the ongoing development of our Rockies, Northeast and Permian segments.

Cash flows used in investing activities during the year ended December 31, 2020 primarily reflected:

- $99.9 million of capital contributions and costs for our equity method investment in Double E; and
- $43.1 million of capital expenditures primarily attributable to the ongoing development of our Rockies, Northeast and Permian segments.

Financing activities. Details of cash flows from financing activities follow.

Cash flows provided by financing activities during the year ended December 31, 2021 primarily reflected:

- Refinancing portions of our long-term debt that included proceeds of $300.0 million from the ABL Facility and $689.5 million from the issuance of the 2026 Secured Notes, offset by the repayment of $33.0 million of the ABL Facility and the repayment in full of the $857.0 million Revolving Credit Facility and $234.0 million of the 2022 Senior Notes;
- $160.0 million of borrowings from the Permian Transmission Credit Facility to fund our capital contributions to our equity method investment in Double E; partially offset by
- $20.2 million paid for debt issuance costs;

Cash flows used in financing activities during the year ended December 31, 2020 primarily reflected:

- $145.6 million paid for the Open Market Repurchases of the 2022 Senior Notes and 2025 Senior Notes;
- $47.5 million paid for tender offer of 2022 Senior Notes and 2025 Senior Notes;
- $41.8 million for the purchase of common units in the GP Buy-In Transaction;
- $35.0 million for the repayment of the ECP Loan;
- $26.5 million for cash paid in connection with the TL Restructuring;
- $25.0 million of cash paid for in connection with the Preferred Tender Offer;
- $180.0 million of net proceeds from borrowings on our Revolving Credit Facility;
- $48.7 million in proceeds from the issuance of our Subsidiary Series A Preferred Units and;
- $35.0 million in proceeds from the ECP Loan.

Contractual Obligations Update

The Partnership's cash flows generated from operations are the primary source for funding various contractual obligations. The table below summarizes the Partnership's major commitments as of December 31, 2021 through 2026 (in thousands):

	Total	2022	2023	2024	2025	2026
2026 Secured Notes, due October 15, 2026 [1] [2]	$ 994,690	$ 56,690	$ 59,500	$ 59,500	$ 59,500	$ 759,500
ABL Facility, due May 1, 2026 [2]	306,048	9,011	9,011	9,011	9,011	270,004
2025 Senior Notes, due April 2025 [2]	311,680	14,919	14,919	14,919	266,923	—
Permian Transmission Credit Facility, due March 8, 2028 [3]	80,920	8,542	14,234	18,946	19,611	19,587
Capital contributions to Double E equity method investment [4]	10,956	10,956	—	—	—	—
Summit Midstream Marketing Firm Transportation obligation to Double E [5]	14,453	2,555	2,555	2,690	3,322	3,331
Global Settlement for 2015 Blacktail Release, inclusive of interest	33,900	5,600	7,300	7,200	7,000	6,800
Lease obligations	3,519	1,346	942	611	464	156
Total	$ 1,756,166	$ 109,619	$ 108,461	$ 112,877	$ 365,831	$ 1,059,378

(1) Amounts above exclude the impact of principal reductions resulting from offers to purchase the 2026 Secured Notes with excess cash flow tenders required in the 2026 Secured Notes indenture.

(2) Amounts include an estimate for interest cost based on either the stated interest rate for fixed rate indebtedness or the interest rate in effect as of December 31, 2021 for variable rate indebtedness.

(3) Amounts assumes the conversion of the Permian Transmission Credit Facility to a Term Loan as of December 31, 2021, with mandatory principal repayments of $4.6 million in 2022, $10.5 million in 2023, $15.5 million in 2024, $16.6 million in 2025 and $17.0 million in 2026.

(4) The Partnership issued a parental guaranty on behalf of its wholly owned subsidiary to fund the subsidiary's pro rata share of required Double E construction project capital calls. As of December 31, 2021, this amount represents the Partnership's best estimate of its remaining obligation to fund Double E for the construction of the Double E Project.

(5) Amounts are Summit Midstream Marketing's gross firm transportation commitments to its equity method investment in Double E, in which the Partnership has a 70% ownership interest. The amounts exclude benefits realized by the Partnership resulting from its proportionate share of net income generated by Double E.

Capital Requirements

Our business is capital intensive, requiring significant investment for the maintenance of existing gathering systems and the acquisition or construction and development of new gathering systems and other midstream assets and facilities. Our Partnership Agreement requires that we categorize our capital expenditures as either:

- maintenance capital expenditures, which are cash expenditures (including expenditures for the addition or improvement to, or the replacement of, our capital assets or for the acquisition of existing, or the construction or development of new, capital assets) made to maintain our long-term operating income or operating capacity; or
- expansion capital expenditures, which are cash expenditures incurred for acquisitions or capital improvements that we expect will increase our operating income or operating capacity over the long term.

For the year ended December 31, 2021, cash paid for capital expenditures totaled $25.0 million which included $7.5 million of maintenance capital expenditures. For the year ended December 31, 2021, we contributed $148.7 million to Double E, which includes $3.0 million in capitalized interest.

We rely primarily on internally generated cash flow as well as external financing sources, including commercial bank borrowings and the issuance of debt, equity and preferred equity securities, and proceeds from asset divestitures to fund our capital expenditures. We believe that our internally generated cash flow and access to debt or equity capital markets, will be adequate to finance our business for the next twelve months without adversely impacting our liquidity.

Considering the current commodity price backdrop and continued uncertainty regarding impacts from the COVID-19 pandemic, we will remain disciplined with respect to future capital expenditures, which will be primarily concentrated on accretive bolt-on opportunities of our existing systems in the Northeast, Rockies and Permian.

We estimate that our 2022 capital program will range from $20.0 million to $35.0 million, including between $10.0 million and $15.0 million of maintenance capital expenditures.

There are a number of risks and uncertainties that could cause our current expectations to change, including, but not limited to, (i) the ability to reach agreement with third parties; (ii) prevailing conditions and outlook in the natural gas, crude oil and NGL industries and markets and (iii) our ability to obtain financing from commercial banks, the capital markets, or other financing sources.

Credit and Counterparty Concentration Risks

We examine the creditworthiness of counterparties to whom we extend credit and manage our exposure to credit risk through credit analysis, credit approval, credit limits and monitoring procedures, and for certain transactions, we may request letters of credit, prepayments or guarantees.

Certain of our customers may be temporarily unable to meet their current obligations. While this may cause a disruption to cash flows, we believe that we are properly positioned to deal with the potential disruption because the vast majority of our gathering assets are strategically positioned at the beginning of the midstream value chain. The majority of our infrastructure is connected directly to our customers' wellheads and pad sites, which means our gathering systems are typically the first third-party infrastructure through which our customers' commodities flow and, in many cases, the only way for our customers to get their production to market.

We have exposure due to nonperformance under our MVC contracts whereby a customer, who does not meet its MVCs, does not have the wherewithal to make its MVC shortfall payments when they become due. We typically receive payment for all prior-year MVC shortfall billings in the quarter immediately following billing. Therefore, our exposure to risk of nonperformance is limited to and accumulates during the current year-to-date contracted measurement period.

Summarized Financial Information

The supplemental summarized financial information below reflects SMLP's separate accounts, the combined accounts of the Co-Issuers and the Guarantor Subsidiaries (the Co-Issuers and, together with the Guarantor Subsidiaries, the "Obligor Group") for the dates and periods indicated. The financial information of the Obligor Group is presented on a combined basis and intercompany balances and transactions between the Co-Issuers and Guarantor Subsidiaries have been eliminated. There were no reportable transactions between the Co-Issuers and Obligor Group and the subsidiaries that were not issuers or guarantors of the 2025 Senior Notes and the 2026 Senior Notes.

Payments to holders of the 2025 Senior Notes and the 2026 Secured Notes are affected by the composition of and relationships among the Co-Issuers, the Guarantor Subsidiaries and Non-Guarantor Subsidiaries, who are unrestricted subsidiaries of SMLP and are not issuers or guarantors of the 2025 Senior Notes and the 2026 Secured Notes. The assets of our unrestricted subsidiaries are not available to satisfy the demands of the holders of the 2025 Senior Notes and the 2026 Secured Notes. In addition, our unrestricted subsidiaries are subject to certain contractual restrictions related to the payment of dividends, and other rights in favor of their non-affiliated stakeholders, that limit their ability to satisfy the demands of the holders of the 2025 Senior Notes and the 2026 Secured Notes.

A list of each of SMLP's subsidiaries that is a guarantor, issuer or co-issuer of our registered securities subject to the reporting requirements in Release 33-10762 is filed as Exhibit 22.1 to this Annual Report.

Summarized Balance Sheet Information. Summarized balance sheet information as of December 31, 2021 and December 31, 2020 follow.

	December 31, 2021	
	SMLP	Obligor Group
	(In thousands)	
Assets		
Current assets	$ 2,495	$ 70,483
Noncurrent assets	4,776	2,149,300
Liabilities		
Current liabilities	$ 12,463	$ 58,658
Noncurrent liabilities	1,771	1,274,803

	December 31, 2020	
	SMLP	Obligor Group
	(In thousands)	
Assets		
Current assets	$ 2,265	$ 78,304
Noncurrent assets	6,952	2,277,807
Liabilities		
Current liabilities	$ 13,339	$ 50,192
Noncurrent liabilities	19,987	1,398,872

Summarized Statements of Operations Information. For the purposes of the following summarized statements of operations, we allocate a portion of general and administrative expenses recognized at the SMLP parent to the Obligor Group to reflect what those entities' results would have been had they operated on a stand-alone basis. Summarized statements of operations for the years ended December 31, 2021 and 2020 follow.

	December 31, 2021	
	SMLP	Obligor Group
	(In thousands)	
Total revenues	$ —	$ 400,619
Total costs and expenses	23,989	317,975
Income (loss) before income taxes and income from equity method investees	(37,618)	13,931
Income from equity method investees	—	9,116
Net income (loss)	$ (37,291)	$ 23,047

	December 31, 2020	
	SMLP	Obligor Group
	(In thousands)	
Total revenues	$ —	$ 383,473
Total costs and expenses	26,169	302,989
Loss before income taxes and income from equity method investees	(26,000)	122,108
Income from equity method investees	—	13,073
Net loss	$ (26,016)	$ 135,181

Critical Accounting Estimates

The discussion and analysis of financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of these financial statements requires management to make estimates and judgments that affect the amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. We evaluate our estimates on an on-going basis, based on historical experience and on various other assumptions that are believed to be reasonable under the circumstances. Actual results may differ from these estimates under different assumptions or conditions. We believe the following describes significant judgments and estimates used in the preparation of our consolidated financial statements.

Impairment of Long-Lived Assets. As of December 31, 2021, we had net property, plant and equipment with a carrying value of approximately $1.7 billion and net amortizing intangible assets with a carrying value of approximately $172.9 million. When evidence exists that we will not be able to recover a long-lived asset's carrying value through future cash flows, we write down the carrying value of the asset to its estimated fair value. We test assets for impairment when events or circumstances indicate that the carrying value of a long-lived asset may not be recoverable. With respect to property, plant and equipment and our amortizing intangible assets, the carrying value of a long-lived asset is not recoverable if the carrying value exceeds the sum of the undiscounted cash flows expected to result from the asset's use and eventual disposal. In this situation, we would recognize an impairment loss equal to the amount by which the carrying value exceeds the asset's fair value. We determine fair value using a combination of approaches, including a market-based approach and an income-based approach in which we discount the asset's expected future cash flows to reflect the risk associated with achieving the underlying cash flows. Any impairment determinations involve significant assumptions and judgments. Differing assumptions regarding any of these inputs could have a significant effect on the various valuations. As such, the fair value measurements utilized within these estimates are classified as non-recurring Level 3 measurements in the fair value hierarchy because they are not observable from objective sources. Due to the volatility of the inputs used, we cannot predict the likelihood of any future impairment.

We evaluate our equity method investments for impairment when we believe the current fair value may be less than the carrying amount and record an impairment if we believe the decline in value is other than temporary.

Adjustments for MVC Shortfall Payments. For our calculation of segment adjusted EBITDA, we estimate the impact of expected MVC shortfall payments based on assumptions that include, but are not limited to, contract terms, historical volume throughput data, and expectations regarding future investment expenditures, customer drilling activities, and customer production volumes.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Interest Rate Risk

Our current interest rate risk exposure is largely related to our indebtedness. As of December 31, 2021, we had $959.5 million principal of fixed-rate debt, $267.0 million outstanding under our variable rate ABL Facility and $160.0 million outstanding under our variable rate Permian Transmission Credit Facility. As of December 31, 2021, we had $144.0 million of interest rate exposure hedged to offset the impact of changes in interest rates on our Permian Transmission Credit Facility. While existing fixed-rate debt mitigates the downside impact of fluctuations in interest rates, future issuances of long-term debt could be impacted by increases in interest rates, which could result in higher overall interest costs. In addition, the borrowings under our ABL Facility, which have a variable interest rate, also expose us to the risk of increasing interest rates. For the year ended December 31, 2021, a hypothetical 1% increase (decrease) in interest rates on our variable rate debt would have increased (decreased) our interest expense by approximately $7.2 million assuming no changes in amounts drawn or other variables under our Revolving Credit Facility, ABL Facility or Permian Transmission.

Commodity Price Risk

We generate a majority of our revenues pursuant to primarily long-term and fee-based gathering agreements, many of which include MVCs and areas of mutual interest. Our direct commodity price exposure relates to (i) the sale of physical natural gas and/or NGLs purchased under percentage-of-proceeds and other processing arrangements with certain of our customers in the Rockies, Piceance, and Permian segments, (ii) the sale of natural gas we retain from certain Barnett segment customers and (iii) the sale of condensate we retain from certain gathering services in the Piceance segment. Our gathering agreements with certain Barnett customers permit us to retain a certain quantity of natural gas that we sell to offset the power costs we incur to operate our electric-drive compression assets. We manage our direct exposure to natural gas and power prices through the use of forward power purchase contracts with wholesale power providers that require us to purchase a fixed quantity of power at a fixed heat rate based on prevailing natural gas prices on the Henry Hub Index. We sell retainage natural gas at prices that are based on the Atmos Zone 3 Index. By basing the power prices on a system and basin-relevant market, we are able to closely associate the relationship between the compression electricity expense and natural gas retainage sales. We do not enter into risk management contracts for speculative purposes.

Item 8. Financial Statements and Supplementary Data.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Summit Midstream, GP, LLC and the unitholders of Summit Midstream Partners, LP

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2021 and 2020, the related consolidated statements of operations, partners' capital, and cash flows, for each of the years then ended, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2022, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Segment Reporting — Refer to Note 18 to the financial statements

Critical Audit Matter Description

As described in Note 18 to the consolidated financial statements, in 2021, the Partnership changed its segment reporting to align with how the Partnership’s Chief Executive Officer, its chief operating decision maker, reviews financial information in order to allocate resources and assess performance. The new segment reporting resulted from changes enacted to optimize commercial efforts and geographic workforce in order to better align its commercial, engineering, and operational capabilities. Therefore, upon filing the 10-K on February 28, 2022, the Partnership updated its segment reporting from eight to five reportable segments. We identified the change in reportable segments as a critical audit matter. We identified the change in reportable segments as a critical audit matter because of the qualitative and economic aggregation criteria and the appropriate period in which to reflect the change, which involved significant management judgment. As such, auditing this change required a high degree of auditor judgment when performing audit procedures and evaluating the results of those procedures.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the change in reportable segments included the following, among others:

- We tested the Partnership’s internal control specific to management’s periodic assessment of the identification and disclosure of reportable segments. Following management’s conclusion that an updated assessment was necessary relative to reportable segments, we tested the Partnership’s control over segment reporting which included a review of each of the factors specified below.
- We evaluated the qualitative and quantitative considerations made by management in concluding it was appropriate to consolidate the eight previously disclosed reportable segments into five reportable segments. This included evaluating the way that management organizes the segments within the Partnership for making operating decisions and assessing performance. Our evaluation included the following:
  - We considered our experience as the Partnership’s auditor of record in evaluating management’s identification of the Chief Executive Officer as the Chief Operating Decision Maker (“CODM”).
  - We corroborated management’s conclusion that the Partnership’s operating segments are organized by five geographic regions through the report that is periodically provided to the CODM to assist with business decisions.

– We evaluated management’s assessments related to the qualitative and quantitative criteria that were considered to consolidate the eight previously disclosed reportable segments into five segments. The qualitative criteria we evaluated included (i) the business activities from which each operating segment recognizes revenues and incurs expenses, (ii) the review of operating results by the CODM to assess performance and to make decisions about resources to be allocated to each segment, and (iii) the presence of discrete financial information for each operating segment. The quantitative criteria we evaluated included (i) the revenue and profit or loss reported for each operating segment in relation to the total revenue and total profit or loss, respectively, reported for all operating segments, (ii) the total assets reported for each operating segment in relation to the combined assets of all operating segments, and (iii) the total reportable segments’ revenue in relation to the Partnership’s total consolidated revenue. We corroborated management’s conclusions through our understanding of the Partnership’s business activities and audited historical financial data.

– We assessed management’s presentation and disclosure against the objectives and principles outlined in relevant accounting literature.

/s/ Deloitte & Touche LLP
Houston, Texas
February 28, 2022

We have served as the Partnership's auditor since 2009.

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2021	December 31, 2020
	(In thousands, except unit amounts)	
ASSETS		
Cash and cash equivalents	$ 7,349	$ 15,544
Restricted cash	12,223	—
Accounts receivable	62,121	61,932
Other current assets	5,676	4,623
Total current assets	87,369	82,099
Property, plant and equipment, net	1,726,082	1,813,810
Intangible assets, net	172,927	199,566
Investment in equity method investees	523,196	392,740
Other noncurrent assets	12,888	11,602
TOTAL ASSETS	$ 2,522,462	$ 2,499,817
LIABILITIES AND CAPITAL		
Trade accounts payable	$ 10,498	$ 11,878
Accrued expenses	14,462	13,036
Deferred revenue	10,374	9,988
Ad valorem taxes payable	8,570	9,086
Accrued compensation and employee benefits	11,019	9,658
Accrued interest	12,737	8,007
Accrued environmental remediation	3,068	1,392
Accrued settlement payable	4,833	—
Other current liabilities	3,676	5,363
Total current liabilities	79,237	68,408
Long-term debt, net	1,355,072	1,347,326
Noncurrent deferred revenue	42,570	48,250
Noncurrent accrued environmental remediation	2,538	1,537
Other noncurrent liabilities	32,357	21,747
Total liabilities	1,511,774	1,487,268
Commitments and contingencies (Note 10)		
Mezzanine Capital		
Subsidiary Series A Preferred Units (91,439 and 85,308 units issued and outstanding at December 31, 2021 and December 31, 2020, respectively)	106,325	89,658
Partners Capital		
Series A Preferred Units (143,447 and 162,109 units issued and outstanding at December 31, 2021 and December 31, 2020, respectively)	169,769	174,425
Common limited partner capital (7,169,834 and 6,110,092 units issued and outstanding at December 31, 2021 and December 31, 2020, respectively)	734,594	748,466
Total partners capital	904,363	922,891
TOTAL LIABILITIES AND CAPITAL	$ 2,522,462	$ 2,499,817

The accompanying notes are an integral part of these consolidated financial statements.

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year ended December 31, 2021	2020
	(In thousands, except per-unit amount)	
Revenues:		
Gathering services and related fees	$ 281,705	$ 302,792
Natural gas, NGLs and condensate sales	82,768	49,319
Other revenues	36,145	31,362
Total revenues	400,618	383,473
Costs and expenses:		
Cost of natural gas and NGLs	81,969	36,653
Operation and maintenance	74,178	86,030
General and administrative	58,166	73,438
Depreciation and amortization	119,076	118,132
Transaction costs	1,677	2,993
Gain on asset sales, net	(369)	(307)
Long-lived asset impairment	10,151	13,089
Total costs and expenses	344,848	330,028
Other income (expense), net	(613)	48
Loss on ECP Warrants	(13,634)	—
Interest expense	(66,156)	(78,894)
Gain (loss) on early extinguishment of debt	(3,523)	203,062
Income (loss) before income taxes and equity method investment income	(28,156)	177,661
Income tax benefit	327	146
Income from equity method investees	7,880	11,271
Net income (loss)	$ (19,949)	$ 189,078
Net income (loss) attributable to Subsidiary Series A Preferred Units	(16,667)	(13,498)
Net loss attributable to noncontrolling interest	—	3,274
Net income (loss) attributable to Summit Midstream Partners, LP	$ (36,616)	$ 178,854
Less: net income attributable to Series A Preferred Units	(15,998)	(26,529)
Add: deemed capital contribution	8,326	110,669
Net income (loss) attributable to common limited partners	$ (44,288)	$ 262,994
Net income (loss) per limited partner unit:		
Common unit – basic	$ (6.57)	$ 73.22
Common unit – diluted	$ (6.57)	$ 71.19
Weighted-average limited partner units outstanding:		
Common units – basic	6,741	3,592
Common units – diluted	6,741	3,694

The accompanying notes are an integral part of these consolidated financial statements.

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF PARTNERS CAPITAL

	Noncontrolling Interest		Partners Capital		
	Series A Preferred Units	Common Noncontrolling Interests [(1)]	Series A Preferred Units	Common Limited Partner Capital	Total
			(In thousands)		
Partners capital, December 31, 2019	$ 293,616	$ 186,070	$ —	$ 305,550	$ 785,236
Net income (loss)	11,875	(3,274)	14,654	152,325	175,580
Unit-based compensation	—	4,054	—	4,057	8,111
Tax withholdings and associated payments on vested SMLP LTIP awards	—	(1,018)	—	(438)	(1,456)
Tax withholdings on Series A Preferred Unit Exchange	—	—	—	(237)	(237)
Net cash distribution to SMLP unitholders	—	(6,037)	—	—	(6,037)
Effect of common issuances under SMLP LTIP	—	2,322	—	(2,322)	—
GP-Buy-In Transaction assumption of noncontrolling interest in SMLP	(305,491)	(182,117)	305,491	182,117	—
Repurchase of common units under GP Buy-In Transaction	—	—	—	(44,078)	(44,078)
Common unit issuance due to TL Restructuring	—	—	—	30,521	30,521
Conversion of Series A Preferred Units to SMLP common units inclusive of a $110.7 million deemed contribution to common unit holders	—	—	(145,720)	120,720	(25,000)
Other	—	—	—	251	251
Partners capital, December 31, 2020	—	—	174,425	748,466	922,891
Net income (loss)	—	—	15,998	(52,614)	(36,616)
Unit-based compensation	—	—	—	4,744	4,744
Tax withholdings and associated payments on vested SMLP LTIP awards	—	—	—	(1,733)	(1,733)
Tax withholdings on Series A Preferred Unit Exchange	—	—	—	(465)	(465)
Effect of 2021 Preferred Exchange Offer, inclusive of an $8.3 million deemed contribution to common unit holders	—	—	(20,654)	20,654	—
Exercise of ECP Warrants	—	—	—	15,542	15,542
Partners capital, December 31, 2021	$ —	$ —	$ 169,769	$ 734,594	$ 904,363

(1) Prior to the GP Buy-in Transaction, common noncontrolling interests reported by Summit Investments included equity interests in SMLP that were not owned by Summit Investments.

The accompanying notes are an integral part of these consolidated financial statements.

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31,	
	2021	2020
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$ (19,949)	$ 189,078
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization	119,995	119,070
Noncash lease expense	1,104	3,242
Amortization of debt issuance costs	7,017	6,608
Unit-based and noncash compensation	4,744	8,111
Income from equity method investees	(7,880)	(11,271)
Distributions from equity method investees	26,760	28,185
Gain on asset sales, net	(369)	(307)
(Gain) loss on extinguishment of debt	3,245	(206,975)
(Gain) loss on ECP Warrants and other	13,635	(393)
Unrealized loss on interest rate swaps	779	134
Long-lived asset impairment	10,151	13,089
Changes in operating assets and liabilities:		
Accounts receivable	(178)	35,352
Trade accounts payable	(89)	(4,063)
Accrued expenses	1,422	2,841
Deferred revenue, net	(5,295)	6,036
Ad valorem taxes payable	(516)	609
Accrued interest	4,730	(3,343)
Accrued environmental remediation, net	2,676	(1,996)
Other, net	3,117	14,582
Net cash provided by operating activities	165,099	198,589
Cash flows from investing activities:		
Capital expenditures	(25,030)	(43,128)
Proceeds from asset sale	8,000	—
Investment in Double E equity method investee	(148,699)	(99,927)
Other, net	—	2,486
Net cash used in investing activities	(165,729)	(140,569)
Cash flows from financing activities:		
Borrowings under 2026 Secured Notes	689,500	—
Repayment of 2022 Senior Notes	(234,047)	—
Borrowings under Permian Transmission Credit Facility	160,000	—
Borrowings under ABL Facility	300,000	—
Repayments on ABL Facility	(33,000)	—
Net cash distributions to noncontrolling interest SMLP unitholders	—	(6,037)
Borrowings under Revolving Credit Facility	—	249,300
Repayments on Revolving Credit Facility	(857,000)	(69,300)
Transaction costs	—	(4,221)
Repayments on SMPH Term Loan before TL Restructuring	—	(6,300)
Open Market Repurchases of 2022 and 2025 Senior Notes	—	(145,567)
Tender Offers of 2022 and 2025 Senior Notes	—	(47,530)
TL Restructuring	—	(26,500)
Proceeds from issuance of Subsidiary Series A Preferred Units, net of issuance costs	—	48,710
Preferred Tender	—	(25,000)
Borrowings under ECP Loans	—	35,000
Repayment of ECP Loans	—	(35,000)
Purchase of common units in GP Buy-In Transaction	—	(41,778)
Debt issuance costs	(20,228)	(2,558)
Proceeds from asset sale	357	288
Other, net	(924)	(2,905)
Net cash used in (provided by) financing activities	4,658	(79,398)
Net change in cash, cash equivalents and restricted cash	4,028	(21,378)
Cash, cash equivalents and restricted cash, beginning of period	15,544	36,922
Cash, cash equivalents and restricted cash, end of period	$ 19,572	$ 15,544

The accompanying notes are an integral part of these consolidated financial statements.

SUMMIT MIDSTREAM PARTNERS, LP AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION, BUSINESS OPERATIONS AND PRESENTATION AND CONSOLIDATION

Organization. Summit Midstream Partners, LP (including its subsidiaries, collectively "SMLP" or the "Partnership") is a Delaware limited partnership that was formed in May 2012 and began operations in October 2012. SMLP is a value-oriented limited partnership focused on developing, owning and operating midstream energy infrastructure assets that are strategically located in unconventional resource basins, primarily shale formations, in the continental United States. The Partnership's business activities are primarily conducted through various operating subsidiaries, each of which is owned or controlled by its wholly owned subsidiary holding company, Summit Holdings, a Delaware limited liability company. As of December 31, 2021, the Partnership indirectly owns its General Partner, and the General Partner is a wholly owned, indirect subsidiary of the Partnership. The General Partner has no assets or liabilities and holds the non-economic general partner interest in the Partnership.

GP Buy-In Transaction. On May 28, 2020, the Partnership closed the transactions contemplated by the Purchase Agreement (the "Purchase Agreement"), dated May 3, 2020, with affiliates of its then private equity sponsor, Energy Capital Partners II, LLC ("ECP"), to acquire Summit Investments. The acquisition of Summit Investments resulted in the Partnership acquiring (a) 2.3 million SMLP common units that were pledged as collateral under the SMPH Term Loan, (b) 0.7 million SMLP common units that were not pledged as collateral under the SMPH Term Loan and (c) a deferred purchase price obligation receivable owed by the Partnership. In addition, the Partnership acquired 0.4 million SMLP common units held by an affiliate of ECP. The total purchase price was $35.0 million in cash and warrants giving ECP the right to purchase up to 0.7 million SMLP common units (refer to Note 12 – Partners' Capital and Mezzanine Capital for additional details). Pursuant to the Purchase Agreement, the Partnership retained any liabilities stemming from the release of produced water from a produced water pipeline operated by Meadowlark Midstream, a subsidiary of the Partnership, that occurred near Williston, North Dakota and was discovered on January 6, 2015. These transactions are collectively referred to as the "GP Buy-In Transaction."

As a result of the GP Buy-In Transaction, the Partnership indirectly owns its General Partner. Following the closing of the GP Buy-In Transaction, the Partnership retired 1.1 million SMLP common units it acquired that were not pledged as collateral under the SMPH Term Loan. The 2.3 million SMLP common units that were pledged as collateral under the SMPH Term Loan were not considered outstanding with respect to voting and distributions under the Partnership Agreement until the closing of the TL Restructuring on November 17, 2020 (refer to Note 9 -Liability Management Transactions).

Under GAAP, the GP Buy-In Transaction was deemed a transaction among entities under common control with a change in reporting entity. Although SMLP is the surviving entity for legal purposes, Summit Investments is the surviving entity for accounting purposes; therefore, the historical financial results included herein, prior to the GP Buy-In Transaction are those of Summit Investments. Prior to the GP Buy-In Transaction, Summit Investments controlled SMLP and SMLP's financial statements were consolidated into Summit Investments.

Reverse Unit Split. On November 9, 2020, after the close of trading on the NYSE, the Partnership effected a 1-for-15 reverse unit split (the "Reverse Unit Split") of its common units. The common units began trading on a split-adjusted basis on November 10, 2020. Pursuant to the Reverse Unit Split, common unitholders received one common unit for every 15 common units owned at the close of business on November 9, 2020. Immediately prior to the Reverse Unit Split, there were 56,624,887 common units issued and outstanding and immediately after the Reverse Unit Split, the number of issued and outstanding common units decreased to 3,774,992.

Business Operations. The Partnership provides natural gas gathering, compression, treating and processing services as well as crude oil and produced water gathering services pursuant to primarily long-term, fee-based agreements with its customers. The Partnership's results are primarily driven by the volumes of natural gas that it gathers, compresses, treats and/or processes as well as by the volumes of crude oil and produced water that it gathers. Other than the Partnership's investments in Double E and Ohio Gathering, all of its business activities are conducted through wholly owned operating subsidiaries.

Presentation and Consolidation. The Partnership prepares its consolidated financial statements in accordance with GAAP as established by the FASB. The Partnership makes estimates and assumptions that affect the reported amounts of assets and liabilities at the balance sheet dates, including fair value measurements, the reported amounts of revenues and expenses and the disclosure of commitments and contingencies. Although management believes these estimates are reasonable, actual results could differ from its estimates.

The consolidated financial statements include the assets, liabilities and results of operations of SMLP and its subsidiaries. All intercompany transactions among the consolidated entities have been eliminated in consolidation. Comprehensive income or loss is the same as net income or loss for all periods presented.

Risks and Uncertainties. The Partnership continues to closely monitor the impact of the COVID-19 pandemic on all aspects of its business, including how it has impacted and will impact its customers, employees, supply chain and distribution network. The Partnership is unable to predict the ultimate impact that COVID-19 may have on its business, future results of operations, financial position or cash flows.

Given the dynamic nature of the COVID-19 pandemic and related market conditions, the Partnership cannot reasonably estimate the period of time that these events will persist or the full extent of the impact they will have on its business. The full extent to which the Partnership's operations may be impacted by the COVID-19 pandemic will depend largely on future developments, which are highly uncertain and cannot be accurately predicted, including changes in the severity of the pandemic, countermeasures taken by governments, businesses and individuals to slow the spread of the pandemic, and the development and availability of treatments and vaccines and the extent to which these treatments and vaccines may remain effective as potential new strains of the coronavirus emerge. Furthermore, the impacts of a potential worsening of global economic conditions and the continued disruptions to and volatility in the financial markets remain unknown.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND RECENTLY ISSUED ACCOUNTING STANDARDS APPLICABLE TO THE PARTNERSHIP

Cash, Cash Equivalents and Restricted Cash. The Partnership considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. Cash that is held by a major bank and has restrictions on its availability to the Partnership is classified as restricted cash. The restricted cash balance of $12.2 million at December 31, 2021 is related to proceeds which are available to finance Permian Transmission's capital calls associated with its investment in Double E, for debt service or other general corporate purposes of Permiam Transmission. See Note 8 - Debt for additional information.

Accounts Receivable. Accounts receivable relate to gathering and other services provided to the Partnership's customers and other counterparties. The Partnership evaluates the collectability of accounts receivable and the need for an allowance for doubtful accounts based on customer-specific facts and circumstances. To the extent the collectability of a specific customer or counterparty receivable is doubtful, the Partnership recognizes an allowance for doubtful accounts. Uncollectible receivables are written off when a settlement is reached for an amount that is less than the outstanding historical balance or a receivable amount is deemed otherwise unrealizable.

Property, Plant and Equipment. The Partnership records property, plant and equipment at historical cost of construction or fair value of the assets at acquisition. The Partnership capitalizes expenditures that extend the useful life of an asset or enhance its productivity or efficiency from its original design over the expected remaining period of use. For maintenance and repairs that do not add capacity or extend the useful life of an asset, the Partnership recognizes expenditures as an expense as incurred. The Partnership capitalizes project costs incurred during construction, including interest on funds borrowed to finance the construction of facilities, as construction in progress. Accrued capital expenditures are reflected in trade accounts payable.

The Partnership records depreciation on a straight-line basis over an asset's estimated useful life and bases its estimates for useful life on various factors including age (in the case of acquired assets), manufacturing specifications, technological advances and historical data concerning useful lives of similar assets. Estimates of useful lives follow.

	Useful lives (In years) **(In years)**
Gathering and processing systems and related equipment	12-30
Other	4-15

Construction in progress is depreciated consistent with its applicable asset class once it is placed in service. Land and line fill are not depreciated.

The Partnership bases an asset's carrying value on estimates, assumptions and judgments for useful life and salvage value. Upon sale, retirement or other disposal, the Partnership removes the carrying value of an asset and its accumulated depreciation from its balance sheet and recognizes the related gain or loss, if any.

Asset Retirement Obligations. The Partnership records a liability for asset retirement obligations only if and when a future asset retirement obligation with a determinable life is identified. For identified asset retirement obligations, the Partnership evaluates whether the expected retirement date and related costs of retirement can be estimated. The Partnership has concluded that its gathering and processing assets have an indeterminate life because they are owned and will operate for an indeterminate period when properly maintained. Because the Partnership does not have sufficient information to reasonably estimate the amount or timing of such obligations and does not have any current plan to discontinue use of any significant assets, the Partnership did not provide for any asset retirement obligations as of December 31, 2021 or 2020.

Amortizing Intangibles. The Partnership has certain acquired gas gathering contracts that had above-market pricing structures at the acquisition date and the Partnership amortizes these favorable contracts using a straight-line method over the contract's estimated useful life. The Partnership defines useful life as the period over which the contract is expected to contribute to the Partnership's future cash flows. These favorable contracts have original terms ranging from 10 years to 20 years and the Partnership recognizes the amortization expense associated with these contracts in Other revenues.

The Partnership amortizes all other gas gathering contracts, or contract intangibles, over the period of economic benefit based upon expected revenues over the life of the contract. The useful life of these contracts ranges from 3 years to 25 years. The Partnership recognizes the amortization expense associated with these contracts in Depreciation and amortization expense.

The Partnership also has rights-of-way associated with municipal easements and easements granted within existing rights-of-way. The Partnership amortizes these intangible assets over the shorter of the contractual term of the rights-of-way or the estimated useful life of the gathering system. The contractual terms of the rights-of-way range from 20 years to 30 years and the Partnership recognizes the amortization expense associated with these rights-of-way assets in Depreciation and amortization expense.

Equity Method Investments. The Partnership accounts for investments in which it exercises significant influence using the equity method so long as it (i) does not control the investee and (ii) is not the primary beneficiary. The Partnership reflects these investments in its consolidated balance sheets under the caption titled "investment in equity method investees."

The Partnership recognizes an other-than-temporary impairment for losses in the value of equity method investees when evidence indicates that the carrying amount is no longer supportable. Evidence of a loss in value might include, but is not limited to, absence of an ability to recover the carrying amount of the investment or an inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. A current fair value of an investment that is less than its carrying amount may indicate a loss in value of the investment. The Partnership evaluates its equity method investments whenever a triggering event exists that would indicate a need to assess the investment for potential impairment.

Impairment of Long-Lived Assets. The Partnership tests assets for impairment when events or circumstances indicate the carrying value of a long-lived asset may not be recoverable. The carrying value of a long-lived asset (except goodwill) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from its use and eventual disposition. If the Partnership concludes that an assets carrying value will not be recovered through future cash flows, the Partnership recognizes an impairment loss on the long-lived asset equal to the amount by which the carrying value exceeds its fair value. The Partnership determines fair value using a combination of market-based and income-based approaches.

Environmental Matters. The Partnership is subject to various federal, state and local laws and regulations relating to the protection of the environment. Liabilities for loss contingencies, including environmental remediation costs, arising from claims, assessments, litigation, fines and penalties and other sources are charged to expense when it is probable that a liability has been incurred and the amount of the assessment and/or remediation can be reasonably estimated. The Partnership accrues for losses associated with environmental remediation obligations when such losses are probable and reasonably estimable. Such accruals are adjusted as further information develops or circumstances change. Recoveries of environmental remediation costs from other parties or insurers are recorded as assets when their realization is assured beyond a reasonable doubt.

Commitments and Contingencies. When required, the Partnership records accruals for loss contingencies in accordance with FASB ASC 450, *Contingencies*. Such determinations are subject to interpretations of current facts and circumstances, forecasts of future events and estimates of the financial impacts of such events.

Noncontrolling Interest and Mezzanine Capital. A noncontrolling interest represents the portion of a consolidated subsidiary that is owned by a third party. Amounts are adjusted by the noncontrolling interest holder's proportionate share of the subsidiary's earnings or losses each period and any distributions that are paid. A noncontrolling interest is reported as a component of equity unless the noncontrolling interest is considered redeemable, in which case the noncontrolling interest is recorded between liabilities and equity (mezzanine or temporary equity) in the Partnership's consolidated balance sheet.

Revenue. The Partnership provides gathering and/or processing services principally under contracts that contain one or more of the following arrangements described below:

- ***Fee-based arrangements.*** Under fee-based arrangements, the Partnership receives a fee or fees for one or more of the following services (i) natural gas gathering, treating, transporting, compressing and/or processing and (ii) crude oil and/or produced water gathering.
- ***Percent-of-proceeds arrangements.*** Under percent-of-proceeds arrangements, the Partnership generally purchases natural gas from producers at the wellhead, or other receipt points, gathers the wellhead natural gas through its gathering system, treats and compresses the natural gas, processes the natural gas and/or sells the natural gas to a third party for processing. The Partnership then remits to its producers an agreed-upon percentage of the actual proceeds received from sales of the residue natural gas and NGLs. Certain of these arrangements may also result

in returning all or a portion of the residue natural gas and/or the NGLs to the producer, in lieu of returning sales proceeds. The margins earned are directly related to the volume of natural gas that flows through the system and the price at which the Partnership is able to sell the residue natural gas and NGLs.

The majority of the Partnership's contracts have a single performance obligation which is either to provide gathering services (an integrated service) or sell natural gas, NGLs and condensate, which are both satisfied when the related natural gas, crude oil and produced water are received and transferred to an agreed upon delivery point. The Partnership also has certain contracts with multiple performance obligations. They include an option for the customer to acquire additional services such as contracts containing MVCs. These performance obligations would also be satisfied when the related natural gas, crude oil and produced water are received and transferred to an agreed upon delivery point. In these instances, the Partnership allocates the contract's transaction price to each performance obligation using its best estimate of the standalone selling price of each service in the contract.

Performance obligations for gathering services are generally satisfied over time. The Partnership utilizes either an output method (i.e., measure of progress) for guaranteed, stand-ready service contracts or an asset/system delivery time estimate for non-guaranteed, as-available service contracts.

Performance obligations for the sale of natural gas, NGLs and condensate are satisfied at a point in time. There are no significant judgments for these transactions because the customer obtains control based on an agreed upon delivery point.

Services are typically billed on a monthly basis and the Partnership does not offer extended payment terms. The Partnership does not have contracts with financing components.

For the contracts described above, the Partnership reflects its revenues in the financial statement captions described below.

Financial statement caption:	Revenue description:
Revenues:	
Gathering services and related fees	• Revenue earned from fee-based gathering, compression, treating and processing services;
Natural gas, NGLs and condensate sales	• Revenue from the sale of physical natural gas purchased from customers percent-of- proceeds arrangements (Costs are presented within cost of natural gas and NGLs); • Revenue from sale of condensate and NGLs retained from gathering services (Costs are presented within operation and maintenance expense); and
Other revenues	• Customer reimbursements to the Partnership for costs incurred by the Partnership on customer's behalf (Recorded on a gross basis).

Certain of the Partnership's gathering and/or processing agreements provide for monthly or annual MVCs. Under these MVCs, customers agree to ship and/or process a minimum volume of production on its gathering systems or to pay a minimum monetary amount over certain periods during the term of the MVC. A customer must make a shortfall payment to the Partnership at the end of the contracted measurement period if its actual throughput volumes are less than its contractual MVC for that period. Certain customers are entitled to utilize shortfall payments to offset gathering fees in one or more subsequent contracted measurement periods to the extent that such customers throughput volumes in a subsequent contracted measurement period exceed its MVC for that contracted measurement period.

The Partnership recognizes customer obligations under their MVCs as revenue and contract assets when (i) it considers it remote that the customer will utilize shortfall payments to offset gathering or processing fees in excess of its MVCs in subsequent periods; (ii) the customer incurs a shortfall in a contract with no banking mechanism or claw back provision; (iii) the customer's banking mechanism has expired; or (iv) it is remote that the customer will use its unexercised right. In making this determination, the Partnership considers both quantitative and qualitative facts and circumstances, including, but not limited to, contract terms, capacity of the associated pipeline or receipt point and/or expectations regarding future investment, drilling and production.

The majority of the Partnership's revenue is derived from long-term, fee-based contracts with its customers, which include original terms of up to 25 years. The Partnership recognizes revenue earned from fee-based gathering, compression, treating and processing services in gathering services and related fees. The Partnership also earns revenue in the Rockies, Piceance and Permian reporting segments from the sale of physical natural gas purchased from its customers under certain percent-of-proceeds arrangements. Under ASC Topic 606, these gathering contracts are presented net within cost of natural gas and NGLs. The Partnership sells natural gas that it retains from certain customers in the Barnett reporting segment to offset the power expenses of the electric-driven compression on the DFW Midstream system. The Partnership also sells condensate and NGLs retained from certain of its gathering services in the Piceance and Permian reporting segments. Revenues from the sale of natural gas and condensate are recognized in Natural gas, NGLs and condensate sales; the associated expense is included in Operation and maintenance expense. Certain customers reimburse the Partnership for costs incurred on their behalf. The Partnership records costs incurred and reimbursed by its customers on a gross basis, with the revenue component recognized in Other revenues.

The transaction price in the Partnership's contracts is primarily based on the volume of natural gas, crude oil or produced water transferred by its gathering systems to the customer's agreed upon delivery point multiplied by the contractual rate. For contracts that include MVCs, variable consideration up to the MVC will be included in the transaction price. For contracts that do not include MVCs, the Partnership does not estimate variable consideration because the performance obligations are completed and settled on a daily basis. For contracts containing noncash consideration such as fuel received in-kind, the Partnership measures the transaction price at the point of sale when the volume, mix and market price of the commodities are known.

The Partnership has contracts with MVCs that are variable and constrained. Contracts with longer than monthly MVCs are reviewed on a quarterly basis and adjustments to those estimates are made during each respective reporting period, if necessary.

The transaction price is allocated if the contract contains more than one performance obligation such as contracts that include MVCs. The transaction price allocated is based on the MVC for the applicable measurement period.

Unit-Based Compensation. For awards of unit-based compensation, the Partnership determines a grant date fair value and recognizes the related compensation expense in the statements of operations over the vesting period for each respective award.

Income Taxes. The Partnership is generally not subject to federal and state income taxes, except as noted below. However, its unitholders are individually responsible for paying federal and state income taxes on their share of its taxable income. Net income or loss for GAAP purposes may differ significantly from taxable income reportable to its unitholders as a result of differences between the tax basis and the GAAP basis of assets and liabilities and the taxable income allocation requirements of the Partnership's governing documents. The aggregate difference in the basis of the Partnership's net assets for financial and income tax purposes cannot be readily determined as the Partnership does not have access to the information about each partner's tax attributes related to the Partnership.

In general, legal entities that are chartered, organized or conducting business in the state of Texas are subject to a franchise tax (the "Texas Margin Tax"). The Texas Margin Tax has the characteristics of an income tax because it is determined by applying a tax rate to a tax base that considers both revenues and expenses. The Partnership's financial statements reflect provisions for these tax obligations.

Interest Rate Swaps. Interest rate swap agreements are reported as either assets or liabilities on the consolidated balance sheet at fair value. Interest rate swap agreements are not designated as cash-flow hedges, and accordingly, the changes in the fair value are recorded in earnings. The Partnership does not use interest rate swap agreements for speculative purposes.

Reclassifications. Certain reclassifications have been made to prior period amounts to conform to current period financial statement presentation. These reclassifications had no effect on the consolidated financial position, results of operations or cash flows of the Partnership.

New accounting standards implemented in this Annual Report.

ASU No. 2018-13 Fair Value Measurement ("ASU 2018-13"). ASU 2018-13 updates the disclosure requirements on fair value measurements including new disclosures for the changes in unrealized gains and losses for the period included in other comprehensive income for recurring Level 3 fair value measurements held at the end of the reporting period and the range and weighted average of significant unobservable inputs used to develop Level 3 fair value measurements. ASU 2018-13 modifies existing disclosures including clarifying the measurement uncertainty disclosure. ASU 2018-13 removes certain existing disclosure requirements including the amount and reasons for transfers between Level 1 and Level 2 fair value measurements and the policy for the timing of transfer between levels. The adoption of ASU 2018-13 on January 1, 2020 did not have a material impact on the Partnership's consolidated financial statements or disclosures.

ASU No. 2016-13 Financial Instruments – Credit Losses ("ASU 2016-13"). ASU 2016-13 requires the use of a current expected loss model for financial assets measured at amortized cost and certain off-balance sheet credit exposures. Under this model, entities will be required to estimate the lifetime expected credit losses on such instruments based on historical experience, current conditions, and reasonable and supportable forecasts. This amended guidance also expands the disclosure requirements to enable users of financial statements to understand an entity's assumptions, models and methods for estimating expected credit losses. The changes are effective for annual and interim periods beginning after December 15, 2019, and amendments should be applied using a modified retrospective approach. The adoption of ASU 2016-13 on January 1, 2020 did not have a material impact on the Partnership's consolidated financial statements or disclosures.

New accounting standards not yet implemented in this Annual Report.

ASU No. 2020-6 Debt – Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging – Contracts in Entity's Own Equity (Subtopic 815 – 40) ("ASU 2020-6"). ASU 2020-6 simplifies the accounting for certain financial instruments with characteristics of liabilities and equity, including convertible instruments and contracts on an entity's own equity. The ASU is part of the FASB's simplification initiative, which aims to reduce unnecessary complexity in GAAP. The ASU's amendments are effective for fiscal years beginning after December 15, 2023, and interim periods within those fiscal years. The Partnership is currently evaluating the provisions of ASU 2020-6 to determine its impact on the Partnership's consolidated financial statements and disclosures.

ASU No. 2020-4 Reference Rate Reform ("ASU 2020-4"). ASU 2020-4 provides optional expedients and exceptions for applying GAAP to contracts, hedging relationships and other transactions affected by reference rate reform on financial reporting. The amendments in ASU 2020-4 are effective as of March 12, 2020 through December 31, 2022. The Partnership is currently evaluating the provisions of ASU 2020-4 to determine its impact on the Partnership's consolidated financial statements and disclosures.

3. REVENUE

The following table presents estimated revenue expected to be recognized over the remaining contract period related to performance obligations that are unsatisfied and are comprised of estimated MVC shortfall payments.

The Partnership applies the practical expedient in paragraph 606-10-50-14 of Topic 606 for certain arrangements that are considered optional purchases (i.e., there is no enforceable obligation for the customer to make purchases) and those amounts are therefore excluded from the table.

	2022	2023	2024	2025	2026	Thereafter
Gathering services and related fees	$ 81,722	$ 63,214	$ 52,412	$ 35,805	$ 21,024	$ —

Revenue by Category. In the following table, revenue is disaggregated by geographic area and major products and services. For more detailed information about reportable segments, see Note 18 -Segment Information.

	Year ended December 31, 2021			
	Gathering services and related fees	Natural gas, NGLs and condensate sales	Other revenues	Total
	(in thousands)			
Reportable Segments:				
Northeast	$ 62,567	$ —	$ —	$ 62,567
Rockies	74,823	48,279	21,985	145,087
Permian	8,230	28,727	3,891	40,848
Piceance	95,235	5,464	4,786	105,485
Barnett	40,850	298	5,443	46,591
Total reportable segments	281,705	82,768	36,105	400,578
Corporate and other	—	—	40	40
Total	$ 281,705	$ 82,768	$ 36,145	$ 400,618

	Year ended December 31, 2020			
	Gathering services and related fees	Natural gas, NGLs and condensate sales	Other revenues	Total
	(in thousands)			
Reportable Segments:				
Northeast	$ 62,250	$ —	$ —	$ 62,250
Rockies	83,107	20,263	17,395	120,765
Permian	10,091	18,857	3,161	32,109
Piceance	106,657	2,612	4,621	113,890
Barnett	40,687	7,587	6,185	54,459
Total reportable segments	302,792	49,319	31,362	383,473
Corporate and other	—	—	—	—
Total	$ 302,792	$ 49,319	$ 31,362	$ 383,473

Contract balances. Contract assets relate to the Partnership's rights to consideration for work completed but not billed at the reporting date and consist of unbilled activity associated with contributions in aid of construction. Contract assets are transferred to trade receivables when the rights become unconditional. The following table provides information about contract assets from contracts with customers:

	December 31, 2021	December 31, 2020
	(In thousands)	
Contract assets, beginning balance	$ 2,026	$ 3,902
Additions	9,274	18,834
Transfers out	(973)	(20,710)
Contract assets, ending balance	$ 10,327	$ 2,026

As of December 31, 2021, receivables with customers totaled $50.5 million and contract assets totaled $10.3 million which were included in the Accounts receivable caption on the consolidated balance sheet.

As of December 31, 2020, receivables with customers totaled $57.5 million and contract assets totaled $2.0 million which were included in the Accounts receivable caption on the consolidated balance sheet.

Contract liabilities (deferred revenue) relate to the advance consideration received from customers primarily for contributions in aid of construction. The Partnership recognizes contract liabilities under these arrangements in revenue over the contract period.

4. PROPERTY, PLANT AND EQUIPMENT

Details on the Partnership's property, plant and equipment follow.

	December 31, 2021	December 31, 2020
	(In thousands)	
Gathering and processing systems and related equipment	$ 2,225,267	$ 2,213,501
Construction in progress	49,082	60,443
Land and line fill	10,644	10,440
Other	51,863	51,276
Total	2,336,856	2,335,660
Less accumulated depreciation	(610,774)	(521,850)
Property, plant and equipment, net	$ 1,726,082	$ 1,813,810

When the carrying amount of a long-lived asset is not recoverable, an impairment is recognized equal to the excess of the asset's carrying value over its fair value, which is based on inputs that are not observable in the market, and thus represent Level 3 inputs under GAAP's fair value hierarchy. The Partnership recognized $10.2 million and $13.1 million of impairments during the fiscal years ended December 31, 2021 and 2020, respectively. Due to the volatility of the inputs used, the Partnership cannot predict the likelihood of any future impairment.

Depreciation expense and capitalized interest for the Partnership follow.

	Year ended December 31, 2021	2020
	(In thousands)	
Depreciation expense	$ 90,711	$ 86,263
Capitalized interest	1,534	$ 3,878

5. AMORTIZING INTANGIBLE ASSETS

Details regarding the Partnership's intangible assets, all of which are subject to amortization, follow.

	December 31, 2021		
	Gross carrying amount	Accumulated amortization	Net
		(In thousands)	
Favorable gas gathering contracts	$ 24,195	$ (17,002)	$ 7,193
Contract intangibles	278,448	(217,245)	61,203
Rights-of-way	159,916	(55,385)	104,531
Total intangible assets	$ 462,559	$ (289,632)	$ 172,927

	December 31, 2020		
	Gross carrying amount	Accumulated amortization	Net
		(In thousands)	
Favorable gas gathering contracts	$ 24,195	$ (16,064)	$ 8,131
Contract intangibles	278,448	(195,243)	83,205
Rights-of-way	157,271	(49,041)	108,230
Total intangible assets	$ 459,914	$ (260,348)	$ 199,566

The Partnership recognized amortization expense of its favorable gas gathering contracts in Other revenues as follows:

	Year ended December 31, 2021	2020
	(In thousands)	
Amortization expense – favorable gas gathering contracts	$ 938	$ 938

The Partnership recognized amortization expense of its contract and right of way intangibles in costs and expenses as follows:

	Year ended December 31, 2021	2020
	(In thousands)	
Amortization expense – contract intangibles	$ 22,002	$ 25,694
Amortization expense – rights-of-way	6,344	6,175

The Partnership's estimated aggregate annual amortization expected to be recognized as of December 31, 2021 for each of the five succeeding fiscal years follows.

	(In thousands)
2022	$ 25,466
2023	25,412
2024	15,241
2025	15,057
2026	12,034
Thereafter	79,717
	$ 172,927

6. EQUITY METHOD INVESTMENTS

The Partnership has equity method investments in Double E and Ohio Gathering, the balances of which are included in the Investment in equity method investees caption on the consolidated balance sheets. Details of the Partnership's equity method investments follows.

	December 31, 2021	December 31, 2020
	(In thousands)	
Double E	$ 280,952	$ 132,852
Ohio Gathering	242,244	259,888
Total	$ 523,196	$ 392,740

Double E. The Partnership, through its wholly-owned subsidiary Summit Permian Transmission, LLC, has a 70% ownership in Double E Pipeline, LLC (the "Double E"). Double E owns a long-haul natural gas pipeline (the "Double E Pipeline") that provides transportation service for residue natural gas from multiple receipt points in the Delaware Basin to various delivery points in and around the Waha hub in Texas. The Double E Pipeline commenced operations in November 2021 and during the years ended December 31, 2021 and 2020, the Partnership made cash investments of $148.7 million and $99.9 million, respectively, in Double E, with such amounts including $3.0 million and $2.7 million of capitalized interest, respectively.

Double E is deemed to be a variable interest entity as defined in GAAP. Summit Permian Transmission was not deemed to be the primary beneficiary of Double E due to the voting rights of Double E's other owner regarding significant matters. The Partnership accounts for its ownership interest in Double E as an equity method investment because it has significant influence over Double E.

For the years ended December 31, 2021 and 2020, other than the investment activity noted above, Double E did not have any material results of operations given that the Double E Pipeline commenced operations in November 2021.

At December 31, 2021 and 2020, the Partnership's carrying amount of its interest in Double E approximated its underlying investment.

Summarized balance sheet information for Double E follows (amounts represent 100% of investee financial information).

	December 31, 2021	December 31, 2020
	(In thousands)	
Current assets	$ 12,353	$ 3,060
Noncurrent assets	410,731	197,463
Total assets	$ 423,084	$ 200,523
Current liabilities	$ 22,836	$ 12,479
Noncurrent liabilities	10,281	4,452
Total liabilities	$ 33,117	$ 16,931

Summarized statements of operations information for Double E follows (amounts represent 100% of investee financial information).

	Year ended December 31, 2021	Year Ended December 31, 2020
	(In thousands)	
Total revenues	$ 3,579	$ —
Total operating expenses	5,281	2,604
Net income (loss)	$ (1,702)	$ (2,604)

Ohio Gathering. The Partnership has investments in OGC and OCC that it collectively refers to as Ohio Gathering. Ohio Gathering owns, operates and is currently developing midstream infrastructure consisting of a liquids-rich natural gas gathering system, a dry natural gas gathering system and a condensate stabilization facility in the Utica Shale in southeastern Ohio. Ohio Gathering provides gathering services pursuant to primarily long-term, fee-based gathering agreements, which include acreage dedications. The Partnership made its initial investment in Ohio Gathering in 2014 and owned approximately 38% of Ohio Gathering at December 31, 2021 and 2020.

Ohio Gathering is accounted for as an equity method investment because it has joint control with non-affiliated owners, which gives the Partnership significant influence.

A reconciliation of the difference between the carrying amount of the Partnership's interest in Ohio Gathering and the Partnership's underlying investment in Ohio Gathering, per Ohio Gathering's books and records, is shown below.

	2021	2020
	(In thousands)	
Investment in Ohio Gathering, December 31	$ 242,244	$ 259,888
December cash distributions	2,222	2,748
Impairment loss	1,971	—
Basis difference	207,927	216,591
Other	137	—
Investment in Ohio Gathering (Books and records), November 30,	$ 454,501	$ 479,227

Summarized balance sheet information for OGC and OCC follows (amounts represent 100% of investee financial information).

	November 30, 2021		November 30, 2020	
	OGC	OCC	OGC	OCC
	(In thousands)			
Current assets	$ 36,967	$ 5,300	$ 32,404	$ 4,902
Noncurrent assets	1,189,921	961	1,240,090	290
Total assets	$ 1,226,888	$ 6,261	$ 1,272,494	$ 5,192
Current liabilities	$ 7,984	$ 3,104	$ 8,424	$ 2,982
Noncurrent liabilities	9,854	4,927	8,441	5,146
Total liabilities	$ 17,838	$ 8,031	$ 16,865	$ 8,128

Summarized statements of operations information for OGC and OCC follows (amounts represent 100% of investee financial information).

	Twelve months ended November 30, 2021		Twelve months ended November 30, 2020	
	OGC	OCC	OGC	OCC
	(In thousands)			
Total revenues	$ 102,140	$ 12,614	$ 114,524	$ 12,931
Total operating expenses	95,399	11,419	103,020	38,502
Net income (loss)	6,742	1,169	11,496	(25,571)

7. DEFERRED REVENUE

Certain of the Partnership's gathering and/or processing agreements provide for monthly or annual MVCs. The amount of the shortfall payment is based on the difference between the actual throughput volume shipped and/or processed for the applicable period and the MVC for the applicable period, multiplied by the applicable gathering or processing fee.

Many of the Partnership's gas gathering agreements contain provisions that can reduce or delay the cash flows that it expects to receive from MVCs to the extent that a customer's actual throughput volumes are above or below its MVC for the applicable contracted measurement period. These provisions include the following:

- To the extent that a customer's throughput volumes are less than its MVC for the applicable period and the customer makes a shortfall payment, it may be entitled to an offset in one or more subsequent periods to the extent that its throughput volumes in subsequent periods exceed its MVC for those periods. In such a situation, the Partnership would not receive gathering fees on throughput in excess of that customer's MVC (depending on the terms of the specific gas gathering agreement) to the extent that the customer had made a shortfall payment with respect to one or more preceding measurement periods (as applicable).

- To the extent that a customer's throughput volumes exceed its MVC in the applicable contracted measurement period, it may be entitled to apply the excess throughput against its aggregate MVC, thereby reducing the period for which its annual MVC applies. As a result of this mechanism, the weighted-average remaining period for which the Partnership’s MVCs apply will be less than the weighted-average of the originally stated MVC contractual terms.
- To the extent that certain of the Partnership’s customers' throughput volumes exceed its MVC for the applicable period, there is a crediting mechanism that allows the customer to build a bank of credits that it can utilize in the future to reduce shortfall payments owed in subsequent periods, subject to expiration if there is no shortfall in subsequent periods. The period over which this credit bank can be applied to future shortfall payments varies, depending on the particular gas gathering agreement.

The balances in deferred revenue as of December 31, 2021 and 2020 are primarily related to contributions in aid of construction which will be recognized as revenue over the life of the contract. A rollforward of current deferred revenue follows.

	(In thousands)
Current deferred revenue, January 1, 2021	$ 9,988
Additions	6,956
Less: revenue recognized	(6,570)
Current deferred revenue, December 31, 2021	$ 10,374

A rollforward of noncurrent deferred revenue follows.

	(In thousands)
Noncurrent deferred revenue, January 1, 2021	$ 48,250
Additions	1,304
Less: reclassification to current deferred revenue	(6,984)
Noncurrent deferred revenue, December 31, 2021	$ 42,570

8. DEBT

Debt for the Partnership at December 31, 2021 and 2020 follows.

	December 31, 2021	December 31, 2020
	(In thousands)	
Revolving Credit Facility: Summit Holdings' variable rate senior secured revolving credit facility due May 13, 2022 [(1)]	$ —	$ 857,000
ABL Facility: Summit Holdings' asset based credit facility due May 1, 2026	267,000	—
Permian Transmission Credit Facility: Permian Transmission's variable rate senior secured credit facility due March 8, 2028	160,000	—
2022 Senior Notes: Summit Holdings' 5.5% senior unsecured notes due August 15, 2022 [(2)]	—	234,047
2025 Senior Notes: Summit Holdings' 5.75% senior unsecured notes due April 15, 2025	259,463	259,463
2026 Secured Notes: Summit Holdings' and Finance Corp's 8.50% senior unsecured second lien notes due October 15, 2026	700,000	—
Less: unamortized debt discount and debt issuance costs	(31,391)	(3,184)
Total long-term debt	$ 1,355,072	$ 1,347,326

(1) The Revolving Credit Facility was repaid in full in November 2021.

(2) The 2022 Senior Notes were repaid in full in November 2021.

The aggregate amount of Partnership's debt maturing during each of the years after December 31, 2021 are as follows (in thousands):

2022	$ —
2023	—
2024	—
2025	259,463
2026	967,000
Thereafter	160,000
Total long-term debt	$ 1,386,463

Revolving Credit Facility. The Partnership's subsidiary, Summit Holdings, had a senior secured revolving credit facility (the "Revolving Credit Facility") which allowed for revolving loans, letters of credit and swingline loans. On November 2, 2021, a portion of the proceeds from the issuance of the 2026 Secured Notes, as described below, together with cash on hand and borrowings under the ABL Facility, as defined below, was used to repay, in full, the obligations under the Revolving Credit Facility.

ABL Facility. Concurrently with the issuance of the 2026 Secured Notes, on November 2, 2021, Summit Holdings, as borrower, entered into a first-lien, senior secured credit agreement, with the Partnership, the subsidiaries party thereto, Bank of America, N.A., as agent, and the several lenders and other agents party thereto, consisting of a $400.0 million asset-based revolving credit facility (the "ABL Facility"), subject to a borrowing base comprised of a percentage of eligible accounts receivable of Summit Holdings and its subsidiaries that guarantee the ABL Facility (collectively, the "ABL Facility Subsidiary Guarantors") and a percentage of eligible above-ground fixed assets including eligible compression units, processing plants, compression stations and related equipment of Summit Holdings and the ABL Facility Subsidiary Guarantors. As of December 31, 2021, the most recent borrowing base determination of eligible assets totaled $691.2 million, an amount greater than the $400.0 million of aggregate commitments.

As of December 31, 2021, the applicable margin under the adjusted LIBOR borrowings was 3.25%, the interest rate was 3.38% and the unused portion of the ABL Facility totaled $109.1 million after giving effect to the issuance of $23.9 million in outstanding but undrawn irrevocable standby letters of credit.

Summit Holdings entered into that certain Loan and Security Agreement governing the ABL Facility (the "ABL Agreement"), dated as of November 2, 2021, by and among Summit Holdings, as borrower, the Partnership, the ABL Facility Subsidiary Guarantors, Bank of America, N.A., as agent, ING Capital LLC, Royal Bank of Canada and Regions Bank, as co-syndication agents, and Bank of America, N.A., ING Capital LLC, RBC Capital Markets and Regions Capital Markets, as joint lead arrangers and joint bookrunners.

The ABL Facility will mature on May 1, 2026; provided that, (a) if the outstanding amount of the 2025 Senior Notes (or any permitted refinancing indebtedness in respect thereof that has a final maturity, scheduled amortization or any other scheduled repayment, mandatory prepayment, mandatory redemption or sinking fund obligation prior to the date that is 120 days after the Termination Date (as defined in the ABL Agreement)) on such date equals or exceeds $50,000,000, then the ABL Facility will mature on December 13, 2024 and (b) if both (i) any amount of the 2025 Senior Notes (or any permitted refinancing indebtedness in respect thereof that has a final maturity, scheduled amortization or any other scheduled repayment, mandatory prepayment, mandatory redemption or sinking fund obligation prior to the date that is 120 days after the Termination Date) is outstanding on such date and (ii) Liquidity (as defined in the ABL Agreement) is less than an amount equal to the sum of the then aggregate outstanding principal amount of the 2025 Senior Notes (or any permitted refinancing indebtedness in respect thereof that has a final maturity, scheduled amortization or any other scheduled repayment, mandatory prepayment, mandatory redemption or sinking fund obligation prior to the date that is 120 days after the Termination Date) plus the Threshold Amount (as defined in the ABL Agreement) on such date, then the ABL Facility will mature on January 14, 2025.

The ABL Facility (together with certain Secured Bank Product Obligations (as defined in the ABL Agreement)) will be jointly and severally guaranteed, on a senior first-priority secured basis (subject to permitted liens), by the Partnership, Summit Holdings and each of the ABL Facility Subsidiary Guarantors.

The ABL Facility restricts, among other things, Summit Holdings' and its Restricted Subsidiaries' (as defined in the ABL Agreement) ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions or repurchase equity; (iii) make payments on or redeem junior lien, unsecured or subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject both to a number of important exceptions and qualifications.

The ABL Facility requires that Summit Holdings not permit (i) the First Lien Net Leverage Ratio (as defined in the ABL Agreement) as of the last day of any fiscal quarter to be greater than 2.50:1.00, or (ii) the Interest Coverage Ratio (as defined in the ABL Agreement) as of the last day of any fiscal quarter to be less than 2.00:1.00. As of December 31, 2021, the First Lien Net Leverage Ratio was 1.10:1.00 and the Interest Coverage Ratio was 4.30:1.00 .

The ABL Facility contains certain events of default customary for instruments of this type. In the case of an event of default arising from certain events of bankruptcy, insolvency or reorganization with respect to Summit Holdings, all outstanding Obligations (as defined in the ABL Agreement) will become due and payable immediately without further action or notice and all commitments under the ABL Facility will terminate.

Pursuant to the ABL Agreement, the Obligations (as defined in the ABL Agreement) are (or, subject to post-closing periods for certain types of collateral, will be) generally secured by a first priority lien on and security interest in (subject to permitted liens), subject to certain exclusions and limitations set forth in the ABL Agreement, (i) substantially all of the personal property of Summit Holdings and the ABL Facility Subsidiary Guarantors, (ii) all equity interests in Summit Holdings and certain other entities, all debt securities and certain rights related to the foregoing, in each case, owned by the Partnership, (iii) Closing Date Material Gathering Station Real Property and Closing Date Pipeline Material Gathering Station Real Property (each, as defined in the ABL Agreement) and certain other material real property interests (including improvements thereon) of Summit Holdings and the ABL Facility Subsidiary Guarantors as provided in the ABL Agreement and (iv) all proceeds of the foregoing collateral.

Intercreditor Agreement.

On November 2, 2021, in connection with the entry into the ABL Facility and issuance of the 2026 Secured Notes, Summit Holdings and the other guarantors party thereto entered into an Intercreditor Agreement (the “Intercreditor Agreement”) with Bank of America, N.A., as first lien representative and collateral agent for the initial first lien claimholders, Regions Bank, as second lien representative for the initial second lien claimholders and collateral agent for the initial second lien claimholders, establishing (i) a first-priority lien (subject to permitted liens) status for the liens on the collateral securing the ABL Facility and any additional first-lien indebtedness and (ii) a junior priority lien (subject to permitted liens) status for the liens on the collateral securing the 2026 Secured Notes and any additional second-lien indebtedness.

Permian Transmission Credit Facility. On March 8, 2021 (the “Permian Closing Date”), the Partnership’s unrestricted subsidiary, Permian Transmission, entered into a Credit Agreement which allows for $175.0 million of senior secured credit facilities (the “Permian Transmission Credit Facilities”), including a $160.0 million Term Loan Facility and a $15.0 million Working Capital Facility. The Permian Transmission Credit Facilities can be used to finance Permian Transmission’s capital calls associated with its investment in Double E, debt service and other general corporate purposes. Unexpended proceeds from draws on the Permian Transmission Credit Facilities are classified as restricted cash on the accompanying unaudited condensed consolidated balance sheets.

As of December 31, 2021, the applicable margin under adjusted LIBOR borrowings was 2.375%, the interest rate was 2.5% and the unused portion of the Permian Transmission Credit Facilities totaled $13.0 million, subject to a commitment fee of 0.7% after giving effect to the issuance of $2.0 million in outstanding but undrawn irrevocable standby letters of credit. As of December 31, 2021, the Partnership was in compliance with the Permian Transmission Credit Facilities covenants. There were no defaults or events of default during the period from the Permian Closing Date to December 31, 2021.

2026 Secured Notes. In 2021, the Co-Issuers issued $700.0 million of 8.500% Senior Secured Second Lien Notes due 2026 (the “2026 Secured Notes”) to eligible purchasers pursuant to Rule 144A and Regulation S of the Securities Act, at a price of 98.5% of their face value. The 2026 Secured Notes will pay interest semi-annually on April 15 and October 15 of each year, commencing on April 15, 2022, and will be jointly and severally guaranteed, on a senior second-priority secured basis (subject to permitted liens), by the Partnership and each restricted subsidiary of the Partnership (other than the Co-Issuers) that is an obligor under the ABL Agreement (as defined below), or under the Co-Issuers’ 2025 Senior Notes on the issue date of the 2026 Secured Notes.

The 2026 Secured Notes will mature on October 15, 2026; provided that, if the outstanding amount of the 2025 Senior Notes (or any refinancing indebtedness in respect thereof that has a final maturity on or prior to the date that is 91 days after the Initial Maturity Date (as defined in the 2026 Secured Notes Indenture)) is greater than or equal to $50.0 million on January 14, 2025, which is 91 days prior to the scheduled maturity date of the 2025 Senior Notes, then the 2026 Secured Notes will mature on January 14, 2025.

The Partnership used the net proceeds from the offering of the 2026 Secured Notes, together with cash on hand and borrowings under the ABL Facility (as defined below), to repay in full all of Summit Holdings’ obligations under the Revolving Credit Facility.

2026 Secured Notes Indenture.

The Co-Issuers issued the 2026 Secured Notes pursuant to an indenture (the “2026 Secured Notes Indenture”), dated as of November 2, 2021, by and among the Co-Issuers, the Partnership, any other Restricted Subsidiary (as defined in the 2026 Secured Notes Indenture) of the Partnership that provides a Notes Guarantee (as defined in the 2026 Secured Notes Indenture) and Regions Bank, as trustee (the “Trustee”) and collateral agent, setting forth specific terms applicable to the 2026 Secured Notes.

At any time prior to October 15, 2023, the Co-Issuers may on any one or more occasions redeem up to 35% of the aggregate principal amount of the 2026 Secured Notes (including any additional notes) issued under the 2026 Secured Notes Indenture at a redemption price of 108.5% of the principal amount of the 2026 Secured Notes, plus accrued and unpaid interest, if any, to, but not including, the redemption date, in an amount not greater than the net cash proceeds of certain equity offerings by the Partnership, provided that: (i) at least 65% of the initial aggregate principal amount of the 2026 Secured Notes (including any additional notes) remains outstanding immediately after the occurrence of such redemption (excluding notes held by the Partnership and its subsidiaries); and (ii) the redemption occurs within 180 days of the date of the closing of each such equity offering by the Partnership. On and after October 15, 2023, the Co-Issuers may redeem all or part of the 2026 Secured Notes at redemption prices (expressed as percentages of principal amount) equal to: (a) 104.250% for the twelve-month period beginning October 15, 2023; (b) 102.125% for the twelve-month period beginning October 15, 2024; and (c) 100.000% for the twelve-month period beginning on October 15, 2025 and at any time thereafter, in each case plus accrued and unpaid interest, if any, to, but not including, the redemption date. In certain circumstances, the Co-Issuers will be required to offer to purchase the 2026 Secured Notes with excess proceeds from asset sales, excess cash flow and upon the occurrence of certain change of control events.

The 2026 Secured Notes Indenture restricts the Partnership’s and its Restricted Subsidiaries’ ability and the ability of certain of their subsidiaries to: (i) incur additional debt or issue preferred stock; (ii) make distributions, repurchase equity or redeem junior lien, unsecured or subordinated debt; (iii) make payments on junior lien, unsecured or subordinated indebtedness; (iv) create liens or other encumbrances; (v) make investments, loans or other guarantees; (vi) engage in transactions with affiliates; and (viii) make acquisitions or merge or consolidate with another entity. These covenants are subject both to a number of important exceptions and qualifications. At any time when the 2026 Secured Notes are rated investment grade by at least two of Moody’s Investors Service, Inc., Standard & Poor’s Ratings Services or Fitch Ratings, Inc., no default under the 2026 Secured Notes Indenture has occurred and is continuing, many of these covenants will terminate.

The 2026 Secured Notes Indenture contains certain events of default customary for instruments of this type.

In the case of an event of default arising from certain events of bankruptcy, insolvency or reorganization with respect to either Co-Issuer, the Partnership, and certain significant subsidiaries of the Partnership, all outstanding Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the Trustee or the holders of at least 25% in principal amount of the then outstanding Notes may declare all the 2026 Secured Notes to be due and payable immediately.

Collateral Agreement.

On November 2, 2021, the Co-Issuers, as pledgors and grantors, entered into, in connection with the 2026 Secured Notes Indenture, a Collateral Agreement (Second Lien), with the Partnership, as a pledgor, each subsidiary guarantor listed therein and Regions Bank, as collateral agent (the “Collateral Agreement”). Pursuant to the Collateral Agreement and the 2026 Secured Notes Indenture, the obligations under the 2026 Secured Notes Indenture are (or, subject to post-closing periods for certain types of collateral, will be) generally secured by a second priority lien on and security interest in (subject to permitted liens) the assets of the Partnership, the Co-Issuers and the subsidiary guarantors securing their obligations under the ABL Facility (as described below under “—ABL Facility”).

Excess Cash Flow Offers to Purchase.

Starting in the first quarter of 2023 with respect to the fiscal year ended 2022, and continuing annually through the fiscal year 2025, the Partnership is required under the terms of the 2026 Secured Notes Indenture to, if it has Excess Cash Flow (as defined in the 2026 Secured Notes Indenture), and subject to its ability to make such an offer under the ABL Credit Facility, offer to purchase an amount of the 2026 Secured Notes, at 100% of the principal amount plus accrued and unpaid interest, equal to 100% of the Excess Cash Flow generated in the prior year.

Generally, if the Partnership does not offer to purchase designated annual amounts of its 2026 Secured Notes or reduce its first lien capacity under the 2026 Secured Notes Indenture per annum from 2023 through 2025, the interest rate on the 2026 Secured Notes are subject to certain rate escalations. Per the terms of the 2026 Secured Notes Indenture, the designated amounts are $50.0 million in aggregate by April 1, 2023, otherwise the interest rate shall automatically increase by 50 basis points per annum; $100.0 million in aggregate by April 1, 2024, otherwise the interest rate shall automatically increase by 100 basis points per annum (minus any amount previously increased); and $200.0 million in aggregate by April 1, 2025, otherwise the interest rate shall automatically increase by 200 basis points per annum (minus any amount previously increased).

To the extent the Partnership makes an offer to purchase, and the offer is not fully accepted by the holders of the 2026 Secured Notes, the Partnership may use any remaining amount not accepted for any purpose not prohibited by the 2026 Secured Notes Indenture or the ABL Facility.

2022 Senior Notes. In July 2014, the Co-Issuers co-issued the 2022 Senior Notes. During 2021, the Co-Issuers redeemed all of the outstanding 2022 Senior Notes at a redemption price equal to 100.0% of the principal amount of the 2022 Senior Notes, plus accrued and unpaid interest.

2025 Senior Notes. In February 2017, the Co-Issuers co-issued the 2025 Senior Notes. The Partnership pays interest on the 2025 Senior Notes semi-annually in cash in arrears on April 15 and October 15 of each year. The 2025 Senior Notes are senior, unsecured obligations and rank equally in right of payment with all of the Partnership's existing and future senior obligations. The 2025 Senior Notes are effectively subordinated in right of payment to all of the Partnership's secured indebtedness, to the extent of the collateral securing such indebtedness.

The Co-Issuers have the right to redeem all or part of the 2025 Senior Notes at a redemption price of 102.875% (with the redemption price declining ratably each year to 100.00% on April 15, 2023), plus accrued and unpaid interest, if any, to, but not including, the redemption date. Debt issuance costs of $7.7 million are being amortized over the life of the 2025 Senior Notes.

As of and during the year ended December 31, 2021, that Partnership was in compliance with the financial covenants governing its 2025 Senior Notes.

SMPH Term Loan and TL Restructuring. Until November 17, 2020, a subsidiary of the Partnership, SMP Holdings, had a senior secured term loan facility with $155.2 million of principal outstanding and a maturity date of May 15, 2022. Borrowings under the SMPH Term Loan bore interest at LIBOR plus 6.00% or ABR plus 5.00%, as defined in the SMPH Term Loan, and were secured by the following collateral: (i) a perfected first-priority lien on, and pledge of (a) all of the capital stock issued by SMP Holdings, (b) 2.3 million SMLP units owned by SMP Holdings, (c) all of the equity interests owned by SMP Holdings in the General Partner, and (ii) substantially all other personal property of SMP Holdings.

On September 29, 2020, SMP Holdings, Summit Investments and, for limited purposes, the Partnership, entered into the TL Restructuring. At the closing of the TL Restructuring on November 17, 2020, the Term Loan Agent executed a Strict Foreclosure on behalf of the Term Loan Lenders on the 2,306,972 common units held by SMP Holdings and pledged as collateral under the SMPH Term Loan, which was then distributed to all SMPH Term Loan Lenders on a pro rata basis. In addition to the Strict Foreclosure, SMP Holdings paid to each of the SMPH Term Loan Lenders its pro rata share of $26.5 million in cash that the Partnership paid to SMP Holdings to fully satisfy its obligation with respect to the deferred purchased price obligation.

As of December 31, 2020, the SMPH Term Loan is fully satisfied and no longer exists.

ECP Loans. On May 28, 2020, in connection with the closing of the GP Buy-In Transaction, Summit Holdings, entered into (i) a Term Loan Credit Agreement (the "ECP NewCo Term Loan Credit Agreement"), with SMP TopCo, LLC, a Delaware limited liability company and affiliate of ECP ("ECP NewCo"), as lender and administrative agent, and Mizuho Bank (USA) ("Mizuho"), as collateral agent, in a principal amount of $28.2 million (the "ECP NewCo Loan"), and (ii) a Term Loan Credit Agreement (the "ECP Holdings Term Loan Credit Agreement" and together with the ECP NewCo Term Loan Credit Agreement, the "ECP Term Loan Credit Agreements"), with ECP Holdings, as lender, and ECP NewCo, as administrative agent and Mizuho, as collateral agent, in a principal amount of $6.8 million (the "ECP Holdings Loan" and together with the ECP NewCo Loan, the "ECP Loans"). The ECP Loans were set to mature on March 31, 2021 and bore interest at a fixed rate of 8.00% per annum, with the interest payment due at maturity of the ECP Loans. With borrowings under the Partnership's Revolving Credit Facility, the Partnership fully repaid all amounts outstanding under the ECP Loans ($35 million of principal and $0.6 million of accrued interest) on August 7, 2020.

9. LIABILITY MANAGEMENT TRANSACTIONS

During the year ended December 31, 2020, the Partnership and its subsidiaries completed several liability management transactions, described below, that resulted in the early extinguishment of an aggregate $306.5 million face value of the Partnership's indebtedness.

Open Market Repurchases. During the year ended December 31, 2020, the Partnership made a number of open market repurchases of the 2022 Senior Notes and 2025 Senior Notes that resulted in the extinguishment of $32.4 million of face value of the 2022 Senior Notes and $201.8 million of face value of the 2025 Senior Notes (the "Open Market Repurchases"). Total cash consideration paid to repurchase the principal amounts outstanding of the 2022 Senior Notes and 2025 Senior Notes, plus accrued interest totaled $150.3 million and the Partnership recognized a $86.4 million gain on the early extinguishment of debt during the year ended December 31, 2020.

Debt Tender Offers. In September 2020, the Co-Issuers completed the Debt Tender Offers to purchase a portion of the 2022 Senior Notes and 2025 Senior Notes. Upon concluding the Debt Tender Offers, the Co-Issuers repurchased $33.5 million principal amount of the 2022 Senior Notes and $38.7 million principal amount of the 2025 Senior Notes. Total cash consideration paid to repurchase the principal amounts outstanding of the 2022 and 2025 Senior Notes, plus accrued interest, totaled $48.7 million, and the Partnership recognized a $23.3 million gain on the early extinguishment of debt during the year ended December 31, 2020.

SMPH Term Loan Restructuring. On November 17, 2020, the Partnership completed the TL Restructuring and recognized a gain of $94.0 million equal to the difference between the face value of the cancelled SMPH Term Loan and the fair value of the total consideration transferred, including unamortized debt issuance costs, and certain direct transaction costs related to the restructuring. The transaction was accounted for under ASC Topic 470-60 *"Troubled Debt Restructuring with Debtors"* and had a total impact of $26.15 per unit.

Summary of gain on extinguishment of debt. The Partnership recognized a $203.1 million gain on extinguishment of debt during the year ended December 31, 2020, the components of which are summarized in the table below.

	ECP Loan Repayment	Open Market Repurchases		Tender Offers		TL Restructuring	Total
(in thousands)		2022 Senior Notes	2025 Senior Notes	2022 Senior Notes	2025 Senior Notes		
Gain on Repurchases of Senior Notes and TL Restructuring	$ —	$ 11,554	$ 76,789	$ 9,223	$ 15,479	$ 99,175	$ 212,220
Debt issue costs	(361)	(143)	(1,541)	(125)	(351)	(2,724)	(5,245)
Transaction costs	(249)	(105)	(105)	(467)	(467)	(2,520)	(3,913)
Gain (loss) on debt extinguishment	$ (610)	$ 11,306	$ 75,143	$ 8,631	$ 14,661	$ 93,931	$ 203,062

10. COMMITMENTS AND CONTINGENCIES

Environmental Matters. Although the Partnership believes that it is in material compliance with applicable environmental regulations, the risk of environmental remediation costs and liabilities are inherent in pipeline ownership and operation. Furthermore, the Partnership can provide no assurances that significant environmental remediation costs and liabilities will not be incurred in the future. The Partnership is currently not aware of any material contingent liabilities that exist with respect to environmental matters, except as noted below.

In 2015, the Partnership learned of the rupture of a four-inch produced water gathering pipeline on the Meadowlark Midstream system near Williston, North Dakota ("2015 Blacktail Release").

As of December 31, 2021, the Partnership has recognized (i) a current liability for remediation effort expenditures expected to be incurred within the next 12 months and (ii) a noncurrent liability for estimated remediation expenditures expected to be incurred subsequent to December 31, 2022. Each of these amounts represent the Partnership's best estimate for costs expected to be incurred. Neither of these amounts have been discounted to its present value.

A rollforward of the Partnership's undiscounted accrued environmental remediation follows and is primarily related to the 2015 Blacktail Release and other environmental remediation activities is below.

	(In thousands)
Accrued environmental remediation, January 1, 2020	$ 4,651
Payments made	(1,722)
Accrued environmental remediation, December 31, 2020	$ 2,929
Payments made	(1,972)
Additional accruals	4,649
Accrued environmental remediation, December 31, 2021	$ 5,606

In the fourth quarter of 2020, the Partnership recognized a $17.0 million loss contingency for the 2015 Blacktail Release as a result of ongoing discussions with multiple federal and state government agencies, including the U.S. Department of Justice, the U.S. Environmental Protection Agency, the North Dakota Industrial Commission, the North Dakota Office of the Attorney General, the North Dakota Department of Environmental Quality, and the North Dakota Game and Fish Department. Subsequently, on August 4, 2021, the Partnership and several of its subsidiaries entered into the following agreements to resolve the U.S. federal and North Dakota state governments' environmental claims with respect to the 2015 Blacktail Release: (i) a Consent Decree with (a) the U.S. Department of Justice ("DOJ"), on behalf of the U.S. Environmental Protection Agency and the U.S. Department of Interior, and (b) the State of North Dakota, on behalf of the North Dakota Department of Environmental Quality and the North Dakota Game and Fish Department ("Consent Decree"), lodged with the U.S. District Court for the District of North Dakota ("U.S. District Court"); (ii) a Plea Agreement with the United States, by and through the U.S. Attorney for the District of North Dakota, and the Environmental Crimes Section of the DOJ ("Plea Agreement"); and (iii) a Consent Agreement with the North Dakota Industrial Commission ("Consent Agreement" together with the Consent Decree and Plea Agreement, the "Global Settlement"). The Partnership increased its loss contingency for the 2015 Blacktail Release during the three months ended June 30, 2021 by $19.3 million. As of December 31, 2021, the accrued loss liability for the 2015 Blacktail Release was $33.2 million.

Key terms of the Global Settlement include (i) payment of penalties and fines totaling $36.3 million, consisting of $1.25 million in natural resource damages to the federal and state governments payable after court approval of the Global Settlement, $25.0 million payable to the federal government over five years, and $10.0 million payable to the state governments over six years, with interest applied to unpaid amounts accruing at a fixed rate of 3.25%, and of which $5.6 million is expected to be paid within the next twelve months; (ii) continuation of remediation efforts at the site of the 2015 Blacktail Release; (iii) other injunctive relief including but not limited to control room management, environmental management system audit, training, and reporting; (iv) guilty pleas for one charge of negligent discharge of a harmful quantity of oil and one charge of knowing failure to immediately report a discharge of oil; and (v) organizational probation for a minimum period of three years from sentencing, including payment in full of certain components of the fines and penalty amounts. The agreements comprising the Global Settlement are subject to the approval of the U.S. District Court for the District of North Dakota (the "U.S. District Court"). The U.S. District Court entered an order making the civil components of the Global Settlement effective on September 28, 2021 and has set a hearing for December 6, 2021 on the criminal components of the Global Settlement, which if accepted by the U.S. District Court will complete approval of the Global Settlement.

Legal Proceedings. The Partnership is involved in various litigation and administrative proceedings arising in the normal course of business. In the opinion of management, any liabilities that may result from these claims or those arising in the normal course of business would not individually or in the aggregate have a material adverse effect on the Partnership's financial position or results of operations.

11. FINANCIAL INSTRUMENTS

Concentrations of Credit Risk. Financial instruments that potentially subject the Partnership to concentrations of credit risk consist of cash and cash equivalents, restricted cash and accounts receivable. The Partnership maintains its cash and cash equivalents and restricted cash in bank deposit accounts that frequently exceed federally insured limits. The Partnership has not experienced any losses in such accounts and does not believe it is exposed to any significant risk.

Accounts receivable primarily comprise amounts due for the gathering, compression, treating and processing services the Partnership provides to its customers and also the sale of natural gas liquids resulting from its processing services. This industry concentration has the potential to impact its overall exposure to credit risk, either positively or negatively, in that the Partnerships customers may be similarly affected by changes in economic, industry or other conditions. The Partnership monitors the creditworthiness of its counterparties and can require letters of credit or other forms of credit assurance for receivables from counterparties that are judged to have substandard credit, unless the credit risk can otherwise be mitigated. The Partnership's top five customers or counterparties accounted for 38% of its total accounts receivable at December 31, 2021, compared to 51% as of December 31, 2020.

Fair Value. The carrying amount of cash and cash equivalents, restricted cash, accounts receivable and trade accounts payable reported on the consolidated balance sheet approximates fair value due to their short-term maturities.

A summary of the estimated fair value of the Partnerships debt financial instruments follows.

	December 31, 2021		December 31, 2020	
	Carrying Value [1]	Estimated fair value (Level 2)	Carrying Value [1]	Estimated fair value (Level 2)
	(in thousands)			
2022 Senior Notes	$ —	$ —	$ 234,047	$ 215,713
2025 Senior Notes	259,463	234,814	259,463	168,002
2026 Secured Notes	700,000	718,083	—	—

[1] Excludes applicable unamortized debt issuance costs and debt discounts.

The carrying value on the balance sheets of the ABL Facility, Revolving Credit Facility and Permian Transmission Credit Facility is its fair value due to its floating interest rate. The fair value for the 2026 Secured Notes, 2022 Senior Notes and 2025 Senior Notes is based on an average of nonbinding broker quotes as of December 31, 2021 and 2020. The use of different market assumptions or valuation methodologies may have a material effect on the estimated fair value of the Senior Notes.

Interest Rate Swaps. In connection with the Permian Transmission Credit Facility, the Partnership entered into amortizing interest rate swap agreements for a notional amount of $144.0 million. These interest rate swaps manage exposure to variability in expected cash flows attributable to interest rate risk. Interest rate swaps convert a portion of the Partnership's variable rate debt to fixed rate debt. The Partnership chooses counterparties for its derivative instruments that it believes are creditworthy at the time the transactions are entered into, and the Partnership actively monitors the creditworthiness where applicable. However, there can be no assurance that a counterparty will be able to meet its obligations to the Partnership. The Partnership presents its derivative positions on a gross basis and does not net the asset and liability positions.

As of December 31, 2021, the Partnership's interest rate swap agreements had a fair value of $0.8 million and are recorded within other current liabilities and other noncurrent liabilities within the consolidated balance sheets.

12. PARTNERS' CAPITAL AND MEZZANINE CAPITAL

Common Units. A rollforward of the number of common limited partner units follows for the period from December 31, 2019 to December 31, 2021.

	Common Units[2]
December 31, 2019	3,021,258
GP Buy-In Transaction[1]	(132,687)
Common units issued for SMLP LTIP, net	95,987
TL Restructuring	2,306,972
Series A Preferred Unit Exchange Offer, net of units withheld for taxes	817,845
Other	717
December 31, 2020	6,110,092
2021 Preferred Exchange Offer, net of units withheld for taxes	538,715
Common units issued for SMLP LTIP, net	106,580
ECP Warrant Exercise	414,447
December 31, 2021	7,169,834

[1] The purchase price for the SMLP common units reflected in the consolidated statement of partners' capital for the year ended December 31, 2020 is comprised of the (i) the $35.0 million cash payment to ECP, (ii) the $2.3 million fair value for the issuance of 0.7 million warrants, and (iii) $6.8 million of advisory fees and other direct costs related to closing the GP Buy-In Transaction.

[2] As adjusted for reverse unit split.

Series A Preferred Units. In November 2017, the Partnership issued 300,000 Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Units (the "Series A Preferred Units") representing limited partner interests in the Partnership at a price to the public of $1,000 per unit.

The Series A Preferred Units rank senior to (i) common units representing limited partner interests in the Partnership and (ii) each other class or series of limited partner interests or other equity securities in the Partnership that may be established in the future that expressly ranks junior to the Series A Preferred Units as to the payment of distributions and amounts payable upon a liquidation event. The Series A Preferred Units rank equal in all respects with each class or series of limited partner interests or other equity securities in the Partnership that may be established in the future that is not expressly made senior or subordinated to the Series A Preferred Units as to the payment of distributions and amounts payable on a liquidation event. The Series A Preferred Units rank junior to (i) all of the Partnership's existing and future indebtedness and other liabilities with respect to assets available to satisfy claims against the Partnership and (ii) each other class or series of limited partner interests or other equity securities in the Partnership established in the future that is expressly made senior to the Series A Preferred Units as to the payment of distributions and amounts payable upon a liquidation event. Income is allocated to the Series A Preferred Units in an amount equal to the earned distributions (whether these distributions are declared by the General Partner to be paid or not) for the respective reporting period.

Distributions on the Series A Preferred Units are cumulative and compounding and are payable semi-annually in arrears on the 15th day of each June and December through and including December 15, 2022, and, thereafter, quarterly in arrears on the 15th day of March, June, September and December of each year (each, a "Distribution Payment Date") to holders of record as of the close of business on the first business day of the month of the applicable Distribution Payment Date, in each case, when, as, and if declared by the General Partner out of legally available funds for such purpose.

The initial distribution rate for the Series A Preferred Units is 9.50% per annum of the $1,000 liquidation preference per Series A Preferred Unit. On and after December 15, 2022, distributions on the Series A Preferred Units will accumulate for each distribution period at a percentage of the liquidation preference equal to the three-month LIBOR plus a spread of 7.43%.

In connection with the GP Buy-In Transaction, the Partnership suspended its distributions to be paid to holders of its Series A Preferred Units, commencing with respect to the quarter ending March 31, 2020. As of December 31, 2021, the amount of accrued and unpaid distributions on the Series A Preferred Units was $29.9 million.

A rollforward of the number of Series A Preferred Units follows for the period from December 31, 2019 to December 31, 2021.

	Series A Preferred Units
December 31, 2019	300,000
Series A Preferred Unit Exchange Offer	(62,816)
Series A Preferred Unit Tender	(75,075)
December 31, 2020	162,109
Series A Preferred Unit Exchange Offer	(18,662)
December 31, 2021	143,447

Series A Preferred Unit Exchange Offers. In April 2021, the Partnership completed an offer to exchange its Series A Preferred Units for newly issued common units, whereby it issued 538,715 SMLP common units, net of units withheld for withholding taxes, in exchange for 18,662 Series A Preferred Units. In July 2020, the Partnership completed an offer to exchange its Series A Preferred Units for newly issued common units, whereby it issued 817,845 SMLP common units, net of units withheld for withholding taxes, in exchange for 62,816 Series A Preferred Units.

Series A Preferred Tender Offer. In December 2020, the Partnership completed a cash tender offer for its Series A Preferred Units whereby it accepted 75,075 Series A Preferred Units for a purchase price of $333.00 per Series A Preferred Unit and an aggregate purchase price of $25.0 million.

Subsidiary Series A Preferred Units. The Partnership has Subsidiary Series A Preferred Units that ranks senior to each other class or series of limited partner interests or other equity securities in Permian Holdco that may be established in the future that expressly ranks junior to the Subsidiary Series A Preferred Units as to the payment of distributions and amounts payable upon a liquidation event. The Subsidiary Series A Preferred Units rank equal in all respects with each class or series of limited partner interests or other equity securities in Permian Holdco that may be established in the future that is not expressly made senior or subordinated to the Subsidiary Series A Preferred Units as to the payment of distributions and amounts payable on a liquidation event. The Subsidiary Series A Preferred Units rank junior to (i) all of Permian Holdco's or a subsidiary of Permian Holdco's future indebtedness and other liabilities with respect to assets available to satisfy claims against Permian Holdco and (ii) each other class or series of limited partner interests or other equity securities in Permian Holdco established in the future that is expressly made senior to the Subsidiary Series A Preferred Units as to the payment of distributions and amounts payable upon a liquidation event. Income is allocated to the Subsidiary Series A Preferred Units in an amount equal to the earned distributions for the respective reporting period.

Distributions on the Subsidiary Series A Preferred Units are cumulative and compounding and are payable 21 days following the quarterly period ended March, June, September and December of each year (each, a “Series A Distribution Payment Date”) to holders of record as of the close of business on the first business day of the month of the applicable Series A Distribution Payment Date, in each case, when, as, and if declared by Permian Holdco out of legally available funds for such purpose.

The distribution rate for the Subsidiary Series A Preferred Units is 7.00% per annum of the $1,000 liquidation preference per Subsidiary Series A Preferred Unit. A pro-rated initial distribution on the Subsidiary Series A Preferred Units was Paid-in-kind (“PIK”) on January 21, 2020 in an amount equal to 7.00% per Subsidiary Series A Preferred Unit plus 1.00% per annum of the undrawn commitment units.

In 2020, the Partnership issued 50,000 Subsidiary Series A Preferred Units at a price of $1,000 per unit for net proceeds of $48.7 million (after deducting underwriting discounts and offering expenses). All proceeds were used to fund capital expenses associated with the Double E Project.

These Subsidiary Series A Preferred Units are considered redeemable securities under GAAP due to the existence of certain redemption provisions that are outside of the Partnership’s control. Therefore, the securities are classified as temporary equity in the mezzanine section of the consolidated balance sheets.

The Partnership records its Subsidiary Series A Preferred Units at fair value upon issuance, net of issuance costs, and subsequently records an effective interest method accretion amount each reporting period to accrete the carrying value to a most probable redemption value that is based on a predetermined internal rate of return measure. The Partnership also elected to make PIK distributions to holders of the Subsidiary Series A Preferred Units during the years ended December 31, 2021 and 2020, which increase the liquidation preference on each Subsidiary Series A Preferred Unit. Ultimately, Net Income (Loss) Attributable to common limited partners includes adjustments for PIK distributions and redemption accretion. During the years ended December 31, 2021 and 2020, the Partnership issued 6,131 and 5,251 Subsidiary Series A Preferred Units, respectively, through PIK transactions. As of December 31, 2021 and 2020, the Partnership had 91,439 and 85,308 Subsidiary Series A Preferred Units outstanding, respectively.

If the Subsidiary Series A Preferred Units were redeemed on December 31, 2021, the redemption amount would be $114.3 million, when considering the applicable multiple of invested capital metric and make-whole amount provisions contained in the Subsidiary Series A Preferred Unit agreement.

The following table shows the change in the Partnership’s Subsidiary Series A Preferred Unit balance during the year ended December 31, 2021:

	(in thousands)
Balance at January 1, 2020	$ 27,450
New issuances	50,000
PIK distributions	5,251
Issuance costs	(1,290)
Redemption accretion	8,247
Balance at December 31, 2020	$ 89,658
PIK distributions	6,131
Redemption accretion	10,536
Balance at December 31, 2021 (1)	$ 106,325

(1) Amount is net of $3.9 million of issuance costs at December 31, 2021.

Warrants. On May 28, 2020 and in connection with the GP Buy-In Transaction, the Partnership issued (i) a warrant to purchase up to 537,307 SMLP common units (8,059,609 SMLP common units prior to the Reverse Unit Split) to ECP NewCo (the “ECP NewCo Warrant”) and (ii) a warrant to purchase up to 129,360 SMLP common units (1,940,391 SMLP common units prior to the Reverse Unit Split) to ECP Holdings (the “ECP Holdings Warrant” and together with the ECP NewCo Warrant, the “ECP Warrants”). The exercise price under the ECP Warrants was 15.35 per SMLP common unit. At issuance the ECP Warrants were valued at $2.3 million using a Black-Scholes model and accounted for as a liability instrument.

On August 5, 2021, the ECP Entities cashlessly exercised all of the ECP Warrants for an aggregate of 414,447 SMLP common units, net of the exercise price, as calculated pursuant to Section 3(c) of the ECP Warrants (the "ECP Warrant Exercise"). For the year ended December 31, 2021, the Partnership recognized a $13.6 million loss related to the ECP Warrants.

Cash Distribution Policy. In connection with the GP Buy-In Transaction, the Partnership suspended its cash distributions to holders of its common units, commencing with respect to the quarter ending March 31, 2020. Upon the resumption of distributions, the Partnership Agreement requires that it distribute all available cash, subject to reserves established by its General Partner, within 45 days after the end of each quarter to unitholders of record on the applicable record date. The amount of distributions paid under this policy is subject to fluctuations based on the amount of cash the Partnership generates from its business and the decision to make any distribution is determined by the General Partner, taking into consideration the terms of the Partnership Agreement.

Cash Distributions Paid and Declared. Prior to the GP Buy-In Transaction, on January 29, 2020, the Board of Directors declared a distribution of $0.125 per unit for the quarterly period ended December 31, 2020 This distribution, which totaled $11.7 million, was paid on February 14, 2020 to unitholders of record at the close of business on February 7, 2020.

13. EARNINGS PER UNIT

The following table details the components of EPU.

	Year ended December 31,	
	2021	2020
	(In thousands, except per-unit amounts)	
Numerator for basic and diluted EPU:		
Allocation of net income (loss) among limited partner interests:		
Net income (loss)	$ (19,949)	$ 189,078
Net income attributable to Subsidiary Series A Preferred Units	(16,667)	(13,498)
Net loss attributable to noncontrolling interest	—	3,274
Net income (loss) attributable Summit Midstream Partners, LP	(36,616)	178,854
Less: Net income attributable to Series A Preferred Unit	(15,998)	(26,529)
Add: Deemed capital contribution	8,326	110,669
Net income (loss) attributable to common limited partners	$ (44,288)	$ 262,994
Denominator for basic and diluted EPU:		
Weighted-average common units outstanding – basic	6,741	3,592
Effect of nonvested phantom units	—	102
Weighted-average common units outstanding – diluted	6,741	3,694
Net Income (Loss) per limited partner unit:		
Common unit – basic	$ (6.57)	$ 73.22
Common unit – diluted	$ (6.57)	$ 71.19
Nonvested anti-dilutive phantom units excluded from the calculation of diluted EPU	203	240

14. SUPPLEMENTAL CASH FLOW INFORMATION

	Year ended December 31, 2021	2020
	(In thousands)	
Supplemental cash flow information:		
Cash interest paid	$ 57,655	$ 79,450
Cash paid for taxes	$ 191	$ 190
Noncash investing and financing activities:		
Capital expenditures in trade accounts payable (period-end accruals)	$ 5,692	$ 6,154
Warrant issuance for GP Buy-In Transaction	—	2,300
Right-of-use assets relating to ASC Topic 842	—	3,685
Fair value of SMLP equity for TL Restructuring	—	30,521
Accretion of Subsidiary Series A Preferred Units	10,536	8,247
Exercise of ECP Warrants	15,542	—

15. UNIT-BASED AND NONCASH COMPENSATION

SMLP Long-Term Incentive Plan. The Partnership's Long-Term Incentive Plan ("SMLP LTIP") provides for equity awards to eligible officers, employees, consultants and directors of the Partnership, thereby linking the recipients' compensation directly to SMLP's performance. The SMLP LTIP provides for the granting, from time to time, of unit-based awards, including common units, restricted units, phantom units, unit options, unit appreciation rights, distribution equivalent rights, profits interest units and other unit-based awards. Grants are made at the discretion of the Board of Directors or Compensation Committee. A total of 1.0 million common units was reserved for issuance pursuant to and in accordance with the SMLP LTIP. As of December 31, 2021, approximately 0.3 million common units remained available for future issuance. Significant items for the year ended December 31, 2021:

- For the year ended December 31, 2021, the Partnership granted 159,239 phantom units and associated distribution equivalent rights to employees. These awards had a grant date fair value of $20.65 per common unit and vest ratably over a three-year period.
- For the year ended December 31, 2021, the Partnership issued 40,002 common units to the Partnership's six independent directors in connection with their annual compensation plan. These awards had a grant date fair value of $28.99 per common unit and vested immediately.

The following table presents phantom unit activity for the periods presented:

	Units	Weighted-average grant date fair value
Nonvested phantom units, December 31, 2019	140,400	$ 115.35
Phantom units granted	345,997	9.20
Phantom units vested	(193,349)	54.07
Phantom units forfeited	(1,357)	119.24
Nonvested phantom units, December 31, 2020	291,691	26.57
Phantom units granted	199,241	22.33
Phantom units vested	(143,768)	30.66
Phantom units forfeited	(13,385)	38.85
Nonvested phantom units, December 31, 2021	333,779	$ 21.78

A phantom unit is a notional unit that entitles the grantee to receive a common unit upon the vesting of the phantom unit or on a deferred basis upon specified future dates or events or, in the discretion of the administrator, cash equal to the fair market value of a common unit. Distribution equivalent rights for each phantom unit provide for a lump sum cash amount equal to the accrued distributions from the grant date to be paid in cash upon the vesting date.

Phantom units granted to date generally vest ratably over a three year period. Grant date fair value is determined based on the closing price of SMLP's common units on the date of grant multiplied by the number of phantom units awarded to the grantee.

Forfeitures are recorded as incurred. Holders of all phantom units granted to date are entitled to receive distribution equivalent rights for each phantom unit, providing for a lump sum cash amount equal to the accrued distributions from the grant date of the phantom units to be paid in cash upon the vesting date. Upon vesting, phantom unit awards may be settled, at the Partnership's discretion, in cash and/or common units, but the current intention is to settle all phantom unit awards with common units.

The intrinsic value of phantom units that vested during the years ended December 31, follows.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Intrinsic value of vested LTIP awards	$ 4,407	$ 2,602

As of December 31, 2021, the unrecognized unit-based compensation related to the SMLP LTIP was $2.6 million. Incremental unit-based compensation will be recorded over the remaining weighted-average vesting period of approximately 1.3 years.

Unit-based compensation recognized in general and administrative expense related to awards under the SMLP LTIP follows.

	Year ended December 31,	
	2021	2020
	(In thousands)	
SMLP LTIP unit-based compensation	$ 4,744	$ 8,111

16. LEASES

Leases. The Partnership leases certain office space and equipment under operating leases. The Partnership leases office space for terms of between 3 and 10 years. Office space leases limit exposure to risks related to ownership, such as fluctuations in real estate prices. The Partnership leases equipment primarily to support its operations in response to the needs of its gathering systems for terms of between 3 and 4 years. The Partnership also leases vehicles under finance leases to support its operations in response to the needs of its gathering systems for a term of 3 years.

Some of the Partnerships leases are subject to annual escalations relating to the Consumer Price Index ("CPI"). While lease liabilities are not remeasured as a result of changes to the CPI, changes to the CPI are treated as variable lease payments and recognized in the period in which the obligation for those payments was incurred.

Significant assumptions or judgments include the determination of whether a contract contains a lease and the discount rate used in the lease liabilities.

The rate implicit in the lease contracts are not readily determinable. In determining the discount rate used in for lease liabilities, the Partnership analyzed certain factors in its incremental borrowing rate, including collateral assumptions and the term used. The incremental borrowing rate on the ABL Facility was 3.38% at December 31, 2021, which reflects the fixed rate at which the Partnership could borrow a similar amount, for a similar term and with similar collateral as in the lease contracts at the commencement date.

ROU assets (included in the other noncurrent assets caption on the Partnership's consolidated balance sheet) and lease liabilities (included in the Other current liabilities and Other noncurrent liabilities captions on the Partnership's consolidated balance sheet) follow:

	December 31, 2021	December 31, 2020
	(In thousands)	
ROU assets		
Operating	$ 2,515	$ 3,736
Finance	792	1,748
	$ 3,307	$ 5,484
Lease liabilities, current		
Operating	$ 1,213	$ 2,298
Finance	167	618
	$ 1,380	$ 2,916
Lease liabilities, noncurrent		
Operating	$ 2,272	$ 3,182
Finance	122	154
	$ 2,394	$ 3,336

Lease cost and Other information follow:

	Year ended December 31,	
	2021	2020
	(In thousands)	
Lease cost		
Finance lease cost:		
Amortization of ROU assets (included in depreciation and amortization)	$ 1,026	$ 1,274
Interest on lease liabilities (included in interest expense)	20	52
Operating lease cost (included in general and administrative expense)	1,722	2,644
	$ 2,768	$ 3,970

	Year ended December 31,	
	2021	2020
	(In thousands)	
Other information		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash outflows from operating leases	$ 1,407	$ 1,472
Operating cash outflows from finance leases	20	52
Financing cash outflows from finance leases	634	1,150
ROU assets obtained in exchange for new operating lease liabilities	—	3,552
ROU assets obtained in exchange for new finance lease liabilities	94	133
Weighted-average remaining lease term (years) - operating leases	5.1	4.9
Weighted-average remaining lease term (years) - finance leases	1.1	1.4
Weighted-average discount rate - operating leases	5 %	5 %
Weighted-average discount rate - finance leases	4 %	4 %

The Partnership recognizes total lease expense incurred or allocated to us in general and administrative expenses. Lease expense related to operating leases, including lease expense incurred on the Partnership's behalf and allocated to us, was as follows:

	Year ended December 31,	
	2021	2020
	(In thousands)	
Lease expense	$ 2,479	$ 3,436

Future minimum lease payments due under noncancelable leases at December 31, 2021, were as follows:

	December 31, 2021	
	(In thousands)	
	Operating	Finance
2022	$ 1,173	$ 173
2023	854	88
2024	573	38
2025	464	—
2026	156	—
2027	160	—
Thereafter	418	—
Total future minimum lease payments	$ 3,798	$ 299

17. RESTRUCTURING

2020 Restructuring Activities. In late 2020, management initiated the 2020 Restructuring Plan, resulting in certain management, facility and organizational changes. Under the 2020 Restructuring Plan, and during the years ended December 31, 2021 and 2020, the Partnership expensed approximately $0.9 million and $5.6 million, respectively, of costs associated with these restructuring activities. These activities consisted primarily of employee-related severance costs and are included within the General and administrative caption on the consolidated statement of operations.

2019 Restructuring Activities. In 2019, management approved and initiated a plan to restructure its operations ("2019 Restructuring Plan"), resulting in certain management, facility and organizational changes. Under the 2019 Restructuring Plan, the Partnership expensed approximately $3.5 million, of costs associated with its restructuring activities. These activities consisted primarily of employee-related costs and consulting costs in support of the project. These costs are included within the General and administrative caption on the consolidated statement of operations**.**

Details for the 2020 and 2019 Restructuring Plans follow.

	Severance Charges		Other Restructuring Charges		Total Severance and Other	
	2021	2020	2021	2020	2021	2020
	(In thousands)					
2020 Restructuring Plan	$ 810	$ 5,591	$ 104	$ 56	$ 914	$ 5,647
2019 Restructuring Plan	—	2,159	—	1,293	—	3,452
	$ 810	$ 7,750	$ 104	$ 1,349	$ 914	$ 9,099

	Accrued December 31, 2019	Charges Incurred	Cash Payments	Accrued December 31, 2020	Charges Incurred	Cash Payments	Accrued December 31, 2021
	(In thousands)						
Employee-related costs	$ 2,816	$ 7,750	$ (7,018)	$ 3,548	$ 810	$ (4,358)	$ —
Other	—	1,349	(1,349)	—	104	(104)	—
Total restructuring costs	$ 2,816	$ 9,099	$ (8,367)	$ 3,548	$ 914	$ (4,462)	$ —

18. SEGMENT INFORMATION

In accordance with ASC No. 280 - Segment Reporting, the Partnership routinely evaluates whether its reportable segments have changed. In the fourth quarter of 2021, the Partnership changed its segment reporting to align with how the General Partner's Chief Executive Officer, its chief operating decision maker, reviews financial information in order to allocate resources and assess performance. The new segment reporting resulted from changes enacted to optimize commercial efforts and geographic workforce in order to better align its commercial, engineering, and operational capabilities.

The Partnership's current reportable segments are described below.

- **Rockies** – Includes the Partnership's wholly owned midstream assets located in the Williston Basin and the DJ Basin.
- **Permian** – Includes the Partnership's wholly owned midstream assets located in the Permian Basin and the equity method investment in Double E.
- **Northeast** – Includes the Partnership's wholly owned midstream assets located in the Utica and Marcellus shale plays and the equity method investment in Ohio Gathering that is focused on the Utica Shale.
- **Piceance** – Includes the Partnership's wholly owned midstream assets located in the Piceance Basin.
- **Barnett** – Includes the Partnership's wholly owned midstream assets located in the Barnett Shale.

Corporate and Other represents those results that: (i) are not specifically attributable to a reportable segment; (ii) are not individually reportable; or (iii) have not been allocated to a reportable segments for the purpose of evaluating their performance, including certain general and administrative expense items, certain natural gas and crude oil marketing services and transaction costs.

Assets by reportable segment follow.

	December 31,	
	2021	2020
	(in thousands)	
Assets:		
Northeast	$ 623,224	$ 645,754
Rockies	592,148	625,793
Permian	458,988	299,421
Piceance	524,218	579,800
Barnett	315,055	336,629
Total reportable segment assets	2,513,633	2,487,397
Corporate and Other	8,829	12,420
Total assets	$ 2,522,462	$ 2,499,817

Revenues by reportable segment follow.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Revenues:		
Northeast	$ 62,567	$ 62,250
Rockies	145,087	120,765
Permian	40,848	32,109
Piceance	105,485	113,890
Barnett	46,591	54,459
Total reportable segments revenue	400,578	383,473
Corporate and Other	40	—
Total revenues	$ 400,618	$ 383,473

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Counterparties accounting for a significant portion of total revenues were as follows:

	Year ended December 31,	
	2021	2020
Percentage of total revenues[1]:		
Counterparty A - Piceance	12 %	13 %
Counterparty B - Northeast	*	5 %
Counterparty B - Permian	*	5 %
Counterparty B - Barnett	*	1 %

* Less than 10% in the aggregate

Depreciation and amortization, including the amortization expense associated with the Partnership's favorable and unfavorable gas gathering contracts as reported in other revenues, by reportable segment follows.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Depreciation and amortization:		
Northeast	$ 17,054	$ 16,891
Rockies	29,513	32,057
Permian	5,858	5,455
Piceance	48,773	45,203
Barnett[1]	16,133	16,112
Total reportable segment depreciation and amortization	117,331	115,718
Corporate and Other	2,664	3,352
Total depreciation and amortization	$ 119,995	$ 119,070

[1] Includes the amortization expense associated with the Partnership's favorable and unfavorable gas gathering contracts as reported in Other revenues.

Cash paid for capital expenditures by reportable segment follow.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Cash paid for capital expenditures:		
Northeast	$ 11,237	$ 7,657
Rockies	9,875	21,596
Permian	2,042	7,014
Piceance	579	1,370
Barnett	766	1,878
Total reportable segment capital expenditures	24,499	39,515
Corporate and Other	531	3,613
Total cash paid for capital expenditures	$ 25,030	$ 43,128

The Partnership assesses the performance of its reportable segments based on segment adjusted EBITDA. The Partnership defines segment adjusted EBITDA as total revenues less total costs and expenses; plus (i) other income excluding interest income, (ii) proportional adjusted EBITDA for equity method investees, (iii) depreciation and amortization, (iv) adjustments related to MVC shortfall payments, (v) adjustments related to capital reimbursement activity, (vi) unit-based and noncash compensation, (vii) impairments (vii) other noncash expenses or losses, less other noncash income or gains and (ix) restructuring expenses. Proportional adjusted EBITDA for the Partnership's equity method investees is defined as the product of (i) total revenues less total expenses, excluding impairments and other noncash income or expense items, and amortization for deferred contract costs; and (ii) ownership interest in Ohio Gathering during the respective period.

For the purpose of evaluating segment performance, the Partnership excludes the effect of Corporate and Other revenues and expenses, such as certain general and administrative expenses (including compensation-related expenses and professional services fees), certain natural gas and crude oil marketing services, transaction costs, interest expense and income tax expense or benefit from segment adjusted EBITDA.

Segment adjusted EBITDA by reportable segment follows.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Reportable segment adjusted EBITDA		
Northeast	$ 83,287	$ 85,854
Rockies	64,517	71,509
Permian	6,614	5,744
Piceance	76,131	88,820
Barnett	36,729	32,093
Total of reportable segments' measures of profit	$ 267,278	$ 284,020

A reconciliation of income or loss before income taxes and income or loss from equity method investees to total of reportable segments' measures of profit or loss follows.

	Year ended December 31,	
	2021	2020
	(In thousands)	
Reconciliation of income (loss) before income taxes and income (loss) from equity method investees to total of reportable segments' measures of profit:		
Income (loss) before income taxes and income (loss) from equity method investees	$ (28,156)	$ 177,661
Add:		
Corporate and Other expense	68,783	60,903
Interest expense	66,156	78,894
Gain on early extinguishment of debt	3,523	(203,062)
Depreciation and amortization[1]	119,995	119,070
Proportional adjusted EBITDA for equity method investees	29,022	31,056
Adjustments related to capital reimbursement activity	(6,571)	(1,395)
Unit-based and noncash compensation	4,744	8,111
Gain on asset sales, net	(369)	(307)
Long-lived asset impairment	10,151	13,089
Total of reportable segments' measures of profit	$ 267,278	$ 284,020

[1] Includes the amortization expense associated with the Partnership's favorable gas gathering contracts as reported in other revenues.

For the years ended December 31, 2021 and 2020, adjustments related to MVC shortfall payments recognize the earnings from MVC shortfall payments ratably over the term of the associated MVC.

Contributions in aid of construction are recognized over the remaining term of the respective contract. The Partnership includes adjustments related to capital reimbursement activity in its calculation of segment adjusted EBITDA to account for revenue recognized from contributions in aid of construction.

19. SUBSEQUENT EVENTS

2022 Preferred Exchange Offer. On January 12, 2022, the Partnership completed an offer to exchange its Series A Preferred Units and accepted for exchange 77,939 Series A Preferred Units for the issuance of 2,853,875 SMLP common units, net of units withheld for withholding taxes.

Permian Transmission Credit Facility conversion. In January 2022, the Partnership converted its Permian Transmission Credit Facility into a $160.0 million term loan facility (the "Permian Term Loan Facility") with an applicable margin of LIBOR borrowings of 2.375%. The Permian Term Loan Facility contains a sculpted 10-year amortization schedule with mandatory quarterly amortization payments due, commencing in the first quarter of 2022.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

There have been no changes in, or disagreements with, accountants on accounting and financial disclosure matters during the years ended December 31, 2021 and 2020.

Item 9A. Controls and Procedures.

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed by us in the reports that we file or submit to the Securities and Exchange Commission under the Exchange Act, is recorded, processed, summarized and reported within the time periods specified by the Commission’s rules and forms, and that information is accumulated and communicated to the management of our General Partner, including our General Partner’s principal executive and principal financial officers (whom we refer to as the Certifying Officers), as appropriate to allow timely decisions regarding required disclosure. SMLP’s management, with the participation of the Chief Executive Officer and Chief Financial Officer of SMLP's General Partner, has evaluated the effectiveness of SMLP’s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this annual report (the “Evaluation Date”). Based on such evaluation, the Chief Executive Officer and Chief Financial Officer of SMLP's General Partner have concluded that, as of the Evaluation Date, SMLP’s disclosure controls and procedures are effective.

Changes in Internal Control Over Financial Reporting

There have not been any changes in SMLP’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth fiscal quarter of 2020 that have materially affected, or are reasonably likely to materially affect, SMLP's internal control over financial reporting.

Management’s Annual Report on Internal Control Over Financial Reporting

Our General Partner is responsible for establishing and maintaining adequate internal control over financial reporting for the Partnership. With our participation, an evaluation of the effectiveness of our internal control over financial reporting was conducted as of December 31, 2021, based on the framework and criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has concluded that our internal control over financial reporting was effective as of December 31, 2021. Our independent registered public accounting firm has issued an audit report on our internal control over financial reporting, included below this report.

/s/ J. HEATH DENEKE

J. Heath Deneke

President and Chief Executive Officer, Summit Midstream GP, LLC (the General Partner of SMLP)

/s/ WILLIAM J. MAULT

William J. Mault

Executive Vice President and Chief Financial Officer, Summit Midstream GP, LLC (the General Partner of SMLP)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Summit Midstream, GP, LLC and the unitholders of Summit Midstream Partners, LP

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Summit Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2021, of the Partnership and our report dated February 28, 2022, expressed an unqualified opinion on those financial statements based on our audit.

Basis for Opinion

The Partnership's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Partnership's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. An entity's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the entity; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the entity are being made only in accordance with authorizations of management and directors of the entity; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the entity's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ Deloitte & Touche LLP
Houston, Texas
February 28, 2022

Item 9B. Other Information.

On February 23, 2022, the Compensation Committee approved a new form of award agreement under the SMLP LTIP pursuant to which it modified the vesting schedule from the previously filed form of award agreement.

This description of the new form of award agreement is qualified in its entirety by reference to the agreement, a copy of which is filed as Exhibit 10.54 to this Annual Report on Form 10-K for the fiscal year ended December 31, 2021.

Item 9C. Disclosure Regarding Foreign Jurisdictions that Prevent Inspections.

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

This information is incorporated by reference to the Partnership’s Proxy Statement for its 2022 Annual Meeting of Limited Partners, which will be filed with the SEC within 120 days of December 31, 2021.

Item 11. Executive Compensation.

This information is incorporated by reference to the Partnership’s Proxy Statement for its 2022 Annual Meeting of Limited Partners, which will be filed with the SEC within 120 days of December 31, 2021.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

This information is incorporated by reference to the Partnership’s Proxy Statement for its 2022 Annual Meeting of Limited Partners, which will be filed with the SEC within 120 days of December 31, 2021.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

This information is incorporated by reference to the Partnership’s Proxy Statement for its 2022 Annual Meeting of Limited Partners, which will be filed with the SEC within 120 days of December 31, 2021.

Item 14. Principal Accounting Fees and Services.

This information is incorporated by reference to the Partnership's Proxy Statement for its 2022 Annual Meeting of Limited Partners, which will be filed with the SEC within 120 days of December 31, 2021.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a)(1) Financial Statements

Our Consolidated Financial Statements and accompanying footnotes are included in Part II, Item 8, of this report.

(2) Financial Statement Schedules

All schedules are omitted because the required information is inapplicable or the information is presented in the financial statements or the notes thereto.

(3) Exhibit Index

The exhibits listed on the accompanying Exhibit Index are filed as part of, or incorporated by reference into, this Annual Report.

Exhibit number	Description
2.1	Purchase Agreement, dated May 3, 2020, by and among Energy Capital Partners II, LP, Energy Capital Partners II-A, LP, Energy Capital Partners II-C (SMLP IP), LP, Energy Capital Partners II-C (Summit IP), LP, Energy Capital Partners II (Summit Co-Invest), LP and Summit Midstream Management, LLC, as contributors, SMP TopCo, LLC and SMLP Holdings, LLC, as sellers, Summit Midstream Partners, LP, as the acquiror, and, solely for certain purposes set forth therein, Summit Midstream Partners GP, LLC (Incorporated herein by reference to Exhibit 2.1 to SMLP's Current Report on Form 8-K dated May 5, 2020 (Commission File No. 001-35666))
3.1	Fourth Amended and Restated Agreement of Limited Partnership of Summit Midstream Partners, LP, dated May 28, 2020 (Incorporated herein by reference to Exhibit 3.1 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
3.2	Second Amended and Restated Limited Liability Company Agreement of Summit Midstream GP, LLC, dated May 28, 2020 (Incorporated herein by reference to Exhibit 3.2 to SMLP's Current Report on Form 8-K filed June 2, 2020 (Commission File No. 001-35666))
3.3	Certificate of Limited Partnership of Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 3.1 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
3.4	Certificate of Formation of Summit Midstream GP, LLC (Incorporated herein by reference to Exhibit 3.4 to SMLP's Form S-1 Registration Statement dated August 21, 2012 (Commission File No. 333-183466))
4.1	Description of Common Units (Incorporated herein by reference to Exhibit 4.1 to SMLP's Form 10-K/A dated April 26, 2021 (Commission File No. 333-183466))
4.2	Investor Rights Agreement, dated as of October 3, 2012, by and among EFS-S, LLC, Summit Midstream GP, LLC and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated October 4, 2012 (Commission File No. 001-35666))
10.1	Strict Foreclosure Agreement, dated November 17, 2020, by and among Summit Midstream Partners Holdings, LLC, Summit Midstream Partners, LLC and Credit Suisse AG, Cayman Islands Branch (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated November 17, 2020 (Commission File No. 001-35666))
10.2	General Assignment and Bill of Sale, dated November 17, 2020, by Summit Midstream Partners Holdings, LLC and Summit Midstream Partners, LLC (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated November 17, 2020 (Commission File No. 001-35666))
10.3	Mutual Release Agreement, dated November 17, 2020, by and among Summit Midstream Partners Holdings, LLC, Summit Midstream Partners, LLC, the lenders party thereto, and Credit Suisse AG, Cayman Islands Branch (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K dated November 17, 2020 (Commission File No. 001-35666)).

10.4	Term Loan Credit Agreement, dated May 28, 2020, by and among Summit Midstream Holdings, LLC, as borrower, SMP TopCo, LLC, as lender and administrative agent and Mizuho Bank (USA), as collateral agent (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.5	Term Loan Credit Agreement, dated May 28, 2020, by and among Summit Midstream Holdings, LLC, as borrower, SMLP Holdings, LLC, as lender, SMP TopCo, LLC, as administrative agent and Mizuho Bank (USA), as collateral agent (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.6	Guarantee and Collateral Agreement, dated May 28, 2020, by and among Summit Midstream Holdings, LLC, Summit Midstream Partners, LP, the subsidiaries listed therein and Mizuho Bank (USA), as collateral agent, relating to the ECP NewCo Term Loan Credit Agreement (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.7	Guarantee and Collateral Agreement, dated May 28, 2020, by and among Summit Midstream Holdings, LLC, Summit Midstream Partners, LP, the subsidiaries listed therein and Mizuho Bank (USA), as collateral agent, relating to the ECP Holdings Term Loan Credit Agreement (Incorporated herein by reference to Exhibit 10.4 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.8	Pari Passu Intercreditor Agreement, dated as of May 28, 2020, among Wells Fargo Bank, National Association, as Revolving Credit Facility Collateral Agent, Mizuho Bank (USA), as NewCo Term Loan Collateral Agent and SMLP Holdings Term Loan Collateral Agent, Summit Midstream Holdings, LLC and other grantors from time to time party thereto (Incorporated herein by reference to Exhibit 10.5 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.9	Warrant to Purchase Common Units, dated May 28, 2020, from Summit Midstream Partners, LP to SMP TopCo, LLC (Incorporated herein by reference to Exhibit 10.6 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.10	Warrant to Purchase Common Units, dated May 28, 2020, from Summit Midstream Partners, LP to SMLP Holdings, LLC (Incorporated herein by reference to Exhibit 10.7 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.11	Operation and Management Services Agreement, dated May 28, 2020, by and among Summit Midstream Partners, LP and Summit Operating Services Company, LLC (Incorporated herein by reference to Exhibit 10.8 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.12	Term Loan Agreement, dated as of March 21, 2017, among Summit Midstream Partners Holdings, LLC, as borrower, the lenders party thereto and Credit Suisse AG, Cayman Islands Branch, as Administrative Agent and Collateral Agent (Incorporated herein by reference to Exhibit 10.9 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.13	Guarantee and Collateral Agreement, dated as of March 21, 2017, by and among Summit Midstream Partners Holdings, LLC, as grantor, Summit Midstream Partners, LLC, as pledgor and grantor and Credit Suisse AG, Cayman Islands Branch, as collateral agent (Incorporated herein by reference to Exhibit 10.10 to SMLP's Current Report on Form 8-K dated June 2, 2020 (Commission File No. 001-35666))
10.14	Amendment to Warrants to Purchase Common Units, dated August 7, 2020, by and among Summit Midstream Partners, LP, SMP TopCo, LLC and SMLP Holdings, LLC (Incorporated herein by reference to Exhibit 10.11 to SMLP's Quarterly Report on Form 10-Q for the period ended September 30, 2020 (Commission File No. 001-35666))

10.15	Transaction Support Agreement, dated September 29, 2020, by and among Summit Midstream Partners Holdings, LLC, Summit Midstream Partners, LLC, Summit Midstream Partners, LP and the Initial Directing Lenders listed therein (Incorporated herein by reference to Exhibit 10.1 to SMLP’s Current Report on Form 8-K dated September 30, 2020 (Commission File No. 001-34666))
10.16	Purchase Agreement, dated as of June 12, 2013, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., Summit Midstream GP, LLC, the Guarantors named therein and the Initial Purchasers named therein (Incorporated herein by reference to Exhibit 1.1 to SMLP's Current Report on Form 8-K dated June 17, 2013 (Commission File No. 001-35666))
10.17	Purchase and Sale Agreement between Meadowlark Midstream Company, LLC, Tioga Midstream, LLC and Hess North Dakota Pipelines LLC dated as of February 22, 2019 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated February 26, 2019 (Commission File No. 001-35666))
10.18	Purchase and Sale Agreement between Meadowlark Midstream Company, LLC, Tioga Midstream, LLC and Hess Infrastructure Partners LP dated as of February 22, 2019 (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated February 26, 2019 (Commission File No. 001-35666))
10.19	Indenture, dated as of June 17, 2013, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors party thereto and U.S. Bank National Association (including form of the 7½% senior notes due 2021) (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated June 17, 2013 (Commission File No. 001-35666))
10.20	Registration Rights Agreement, dated as of June 17, 2013, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors named therein and the Initial Purchasers named therein (Incorporated herein by reference to Exhibit 4.2 to SMLP's Current Report on Form 8-K dated June 17, 2013 (Commission File No. 001-35666))
10.21	Joinder Agreement, dated as of June 4, 2013, by and among Summit Midstream Holdings, LLC, The Royal Bank of Scotland plc, as Administrative Agent, and the lenders party thereto (Incorporated herein by reference to Exhibit 10.2 to SMLP's Current Report on Form 8-K dated June 5, 2013 (Commission File No. 001-35666))
10.22	Third Amended and Restated Credit Agreement dated as of May 26, 2017 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated May 30, 2017 (Commission File No. 001-35666))
10.23	First Amendment to the Third Amended and Restated Credit Agreement dated as of September 22, 2017 (Incorporated herein by reference to Exhibit 10.7 to SMLP’s Annual Report on Form 10-K for the fiscal year ended December 31, 2017 (Commission File No. 001-35666))
10.24	Second Amendment to Third Amended and Restated Credit Agreement dated as of June 26, 2019 (Incorporated herein by reference to Exhibit 10.2 to SMLP's Quarterly Report on Form 10-Q dated August 9, 2019 (Commission File No. 001-35666))
10.25	Third Amendment to Third Amended and Restated Credit Agreement and Second Amendment to Second Amended and Restated Guarantee and Collateral Agreement dated as of December 24, 2019 (Incorporated by reference to Exhibit 10.11 to SMLP’s Annual Report on Form 10-K for the fiscal year ended December 31, 2019 (Commission File No. 001-35666))
10.26	Fourth Amendment to Third Amended and Restated Credit Agreement and Third Amendment to Second Amended and Restated Guarantee and Collateral Agreement, dated as of December 18, 2020, by and among Summit Midstream Holdings, LLC, each of the other Loan Parties party thereto, Wells Fargo Bank, National Association, as administrative and collateral agent and the Lenders party thereto (Incorporated herein by reference to Exhibit 10.1 to SMLP’s Current Report on Form 8-K dated December 18, 2020 (Commission File No. 01-35666))

10.27	Amended and Restated Limited Liability Company Agreement of Summit Permian Transmission Holdco, LLC, dated as of December 24, 2019 (Incorporated by reference to Exhibit 10.12 to SMLP’s Annual Report on Form 10-K for the fiscal year ended December 31, 2019 (Commission File No. 001-35666))
10.28	Amended and Restated Guarantee and Collateral Agreement dated as of November 1, 2013 (Incorporated herein by reference to Exhibit 10.7 to SMLP's 2013 Annual Report on Form 10-K for the fiscal year ended December 31, 2013 (Commission File No. 001-35666))
10.29	Base Indenture, dated as of July 15, 2014, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp. and U.S. Bank National Association (Incorporated herein by reference to Exhibit 4.1 to SMLP's Current Report on Form 8-K dated July 9, 2014 (Commission File No. 001-35666))
10.30	First Supplemental Indenture, dated as of July 15, 2014, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors party thereto and U.S. Bank National Association (including form of the 5½% senior notes due 2022) (Incorporated herein by reference to Exhibit 4.2 to SMLP's Current Report on Form 8-K dated July 9, 2014 (Commission File No. 001-35666))
10.31	Second Supplemental Indenture, dated as of February 15, 2017, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors party thereto and U.S. Bank National Association (including form of the 5.75% senior notes due 2025) (Incorporated herein by reference to Exhibit 4.2 to SMLP’s Current Report on Form 8-K dated February 17, 2017 (Commission File No. 001-35666))
10.32	Equity Distribution Agreement, dated June 12, 2015, among the Partnership, the General Partner, the Operating Company, Citigroup Global Markets Inc., Deutsche Bank Securities Inc. and RBC Capital Markets, LLC. (Incorporated herein by reference to Exhibit 1.1 to SMLP's Current Report on Form 8-K dated June 12, 2015 (Commission File No. 001-35666))
10.33	Contribution Agreement between Summit Midstream Partners Holdings, LLC and Summit Midstream Partners, LP dated as of February 25, 2016 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Form 8-K filed March 1, 2016 (Commission File No. 001-35666))
10.34	Amendment to Contribution Agreement between Summit Midstream Partners Holdings, LLC and Summit Midstream Partners, LP dated February 25, 2019 (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K dated February 26, 2019 (Commission File No. 001-35666))
10.35	Amendment No. 2 to Contribution Agreement between Summit Midstream Partners Holdings, LLC and Summit Midstream Partners, LP dated November 7, 2019 (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K dated November 8, 2019 (Commission File No. 001-35666))
10.36	Amendment No. 3 to Contribution Agreement, dated November 17, 2020, by and between Summit Midstream Partners Holdings, LLC and Summit Midstream Partners, LP (Incorporated herein by reference to Exhibit 10.4 to SMLP’s Current Report on Form 8-K dated November 17, 2020 (Commission File No. 001-35666))
10.37	Credit Agreement, dated as of March 8, 2021, among Summit Permian Transmission, LLC, as borrower, MUFG Bank Ltd., as administrative agent, Mizuho Bank (USA), as collateral agent, ING Capital LLC, Mizuho Bank, Ltd. and MUFG Union Bank, N.A., as L/C issuers, coordinating lead arrangers and joint bookrunners, and the lenders from time to time party thereto (Incorporated herein by reference to Exhibit 10.1 to SMLP’s Quarterly Report on Form 10-Q dated May 7, 2021 (Commission File No. 333-183466))
10.38	Joint Factual Statement (Incorporated herein by reference to Exhibit 10.1 to SMLP’s Quarterly Report on Form 10-Q for the three months ended June 30, 2021 dated August 9, 2021 (Commission File No. 333-183466))

10.39		Criminal Plea Agreement (Incorporated herein by reference to Exhibit 10.2 to SMLP’s Quarterly Report on Form 10-Q for the three months ended June 30, 2021 dated August 9, 2021 (Commission File No. 333-183466))
10.40		Consent Decree (Incorporated herein by reference to Exhibit 10.3 to SMLP’s Quarterly Report on Form 10-Q for the three months ended June 30, 2021 dated August 9, 2021 (Commission File No. 333-183466))
10.41	†	Indenture, dated as of November 2, 2021, by and among Summit Midstream Holdings, LLC, Summit Midstream Finance Corp., the Guarantors party thereto and Regions Bank, as trustee (including form of the 8.500% Senior Secured Second Lien Notes due 2026) (Incorporated herein by reference to Exhibit 4.1 to SMLP's Quarterly Report on Form 10-Q dated November 4, 2021 (Commission File No. 001-35666))
10.42		Collateral Agreement, dated as of November 2, 2021, by and among Summit Midstream Partners, LP, as a pledgor, Summit Midstream Holdings, LLC and Summit Midstream Finance Corp., as pledgors and grantors, the Subsidiary Guarantors party therein, and Regions Bank, as collateral agent (Incorporated herein by reference to Exhibit 10.4 to SMLP’s Quarterly Report on Form 10-Q for the three months ended September 30, 2021 dated November 4, 2021 (Commission File No. 333-183466))
10.43		Loan and Security Agreement, dated as November 2, 2021, among Summit Midstream Holdings, as borrower, Summit Midstream Partners, LP and certain subsidiaries from time to time party thereto, as guarantors, Bank of America, N.A., as agent, ING Capital LLC, Royal Bank of Canada and Regions Bank, as co-syndication agents, joint lead arrangers and joint bookrunners (Incorporated herein by reference to Exhibit 10.5 to SMLP’s Quarterly Report on Form 10-Q for the three months ended September 30, 2021 dated November 4, 2021 (Commission File No. 333-183466))
10.44	†	Intercreditor Agreement, dated as of November 2, 2021, by and among Bank of America, N.A., as first lien representative and collateral agent for the initial first lien claimholders, Regions Bank, as second lien representative for the initial second lien claimholders and as collateral agent for the initial second lien claimholders, acknowledged and agreed to by Summit Midstream Holdings, LLC and the other grantors referred to therein (Incorporated herein by reference to Exhibit 10.6 to SMLP’s Quarterly Report on Form 10-Q for the three months ended September 30, 2021 dated November 4, 2021 (Commission File No. 333-183466))
10.45		Equity Restructuring Agreement by and among Summit Midstream Partners, LP, Summit Midstream GP, LLC and Summit Midstream Partners Holdings, LLC dated as of February 25, 2019 (Incorporated herein by reference to Exhibit 10.4 to SMLP's Current Report on Form 8-K dated February 26, 2019 (Commission File No. 001-35666))
10.46	*	Amended and Restated Employment Agreement, effective September 1, 2020, by and between Summit Midstream Partners, LLC and Marc D. Stratton (Incorporated herein by reference to Exhibit 10.41 to SMLP’s Annual Report on Form 10-K for the fiscal year ended December 31, 2020 (Commission File No. 001-35666))
10.47	*	Form of Retention Bonus Agreement (Incorporated herein by reference to Exhibit 10.1 to SMLP’s Current Report on Form 8-K dated June 11, 2019 (Commission File Number 001-35666))
10.48		Employment Agreement effective September 16, 2019, by and between Summit Midstream Partners, LLC and Heath Deneke (Incorporated herein by reference to Exhibit 10.1 to SMLP’s Current Report on Form 8-K dated August 9, 2019 (Commission File Number 001-35666))
10.49	*	Employment Agreement, effective as of September 4, 2020, by and between Summit Midstream Partners, LP and James Johnston (Incorporated herein by reference to Exhibit 10.4 to SMLP’s Form 10-Q dated November 6, 2020 (Commission File No. 001-35666))
10.50	*	Summit Midstream Partners, LP 2012 Long-Term Incentive Plan, as amended and restated (incorporated herein by reference to Exhibit 10.1 to SMLP’s Current Report on Form 8-K dated March 20, 2020 (Commission File No. 001-35666))

10.51	*	Summit Midstream Partners, LP 2012 Long-Term Incentive Plan Phantom Unit Agreement (Incorporated herein by reference to Exhibit 10.1 to SMLP's Current Report on Form 8-K filed March 17, 2014 (Commission File No. 001-35666))
10.52	*	Form of Director Unit Award Agreement (Incorporated herein by reference to Exhibit 10.3 to SMLP's Current Report on Form 8-K filed October 4, 2012 (Commission File No. 001-35666))
10.53	*	Summit Midstream Partners, LLC Deferred Compensation Plan effective as of July 1, 2013 (Incorporated herein by reference to Exhibit 4.3 to SMLP's Form S-8 Registration Statement dated June 28, 2013 (Commission File No. 333-189684))
10.54	***	Form of Director Unit Award Agreement (2022)
21.1		List of Subsidiaries (Incorporated herein by reference to Exhibit 21.1 to SMLP’s Form 8-K filed August 10, 2020 (Commission File No. 001-35666))
22.1		Summit Midstream Partners, LP Subsidiary Issuers and Guarantors of Registered Securities (Incorporated herein by reference to Exhibit 22.1 to SMLP's Report on Form 10-Q filed May 8, 2020 (Commission File No. 001-35666)).
23.1	***	Consent of Deloitte & Touche LLP
31.1	***	Rule 13a-14(a)/15d-14(a) Certification, executed by Heath Deneke, President, Chief Executive Officer and Director
31.2	***	Rule 13a-14(a)/15d-14(a) Certification, executed by William J. Mault, Executive Vice President and Chief Financial Officer
32.1	***	Certifications required by Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350), executed by Heath Deneke, President, Chief Executive Officer and Director, and William J. Mault, Executive Vice President and Chief Financial Officer
101.INS	**	XBRL Instance Document – the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH	**	Inline XBRL Taxonomy Extension Schema
101.CAL	**	Inline XBRL Taxonomy Extension Calculation Linkbase
101.DEF	**	Inline XBRL Taxonomy Extension Definition Linkbase
101.LAB	**	Inline XBRL Taxonomy Extension Label Linkbase
101.PRE	**	Inline XBRL Taxonomy Extension Presentation Linkbase
104		Cover Page Interactive Data File (embedded within the Inline XBRL document).

* Management contract or compensatory plan or arrangement required to be filed as an exhibit pursuant to Item 15(b) of this report

† Certain portions have been omitted pursuant to a confidential treatment request. Omitted information has been filed separately with the SEC.

** Pursuant to Rule 406T of Regulation S-T, the Interactive Data Files on Exhibit 101 hereto are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, are deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise are not subject to liability under those sections. The financial information contained in the XBRL (eXtensible Business Reporting Language)-related documents is unaudited and unreviewed.

*** Filed herewith

(c) Financial Statement Schedules

Not applicable.

Item 16. Form 10-K Summary.

Not applicable.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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.

	Summit Midstream Partners, LP
	(Registrant)
	By: Summit Midstream GP, LLC (its General Partner)
February 28, 2022	*/s/ WILLIAM J. MAULT*
	William J. Mault, Executive Vice President and Chief Financial Officer (Principal Financial Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ J. HEATH DENEKE J. Heath Deneke	Director, President and Chief Executive Officer (Principal Executive Officer)	February 28, 2022
/s/ WILLIAM J. MAULT William J. Mault	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2022
/s/ MATTHEW B. SICINSKI Matthew B. Sicinski	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 28, 2022
/s/ JAMES J. CLEARY James J. Cleary	Director	February 28, 2022
/s/ LEE JACOBE Lee Jacobe	Director	February 28, 2022
/s/ ROBERT J. MCNALLY Robert J. McNally	Director	February 28, 2022
/s/ JERRY L. PETERS Jerry L. Peters	Director	February 28, 2022
/s/ MARGUERITE WOUNG-CHAPMAN Marguerite Woung-Chapman	Director	February 28, 2022

EXHIBIT 10.54

February 24, 2022

SUMMIT MIDSTREAM PARTNERS, LP
2012 LONG-TERM INCENTIVE PLAN
_____ LTIP GRANT AWARD AGREEMENT

Pursuant to this ____ LTIP Grant Award Agreement, dated as of ____________ (this "**Agreement**") and the Summit Midstream Partners, LP 2012 Long-Term Incentive Plan, as amended and restated (the "**Plan**"), Summit Midstream GP, LLC (the "**Company**"), as the general partner of Summit Midstream Partners, LP (the "**Partnership**"), hereby grants to [_______________] (the "**Participant**") the following Other Unit-Based Award within the meaning of the Plan (the "**Award**") consisting, in part, of Phantom Units (the "**Phantom Units**"), and, in part, of a dollar-denominated cash amount (the "**Retention Component**"). In the event of any conflict between the terms of this Agreement and the Plan (the terms and conditions of which are hereby incorporated into this Agreement by reference), the terms of the Plan shall control. Except as otherwise expressly provided herein, all capitalized terms used in this Agreement, but not defined, shall have the meanings provided in the Plan.

The effectiveness of the Award requires your acceptance by executing and returning the signature page hereto within five days of the Grant Date and the Award may be revoked if not so accepted.

GRANT NOTICE

Subject to the terms and conditions of this Agreement, the principal features of the Award are as follows:

Number of Phantom Units: [___________] Phantom Units, each of which is hereby granted in tandem with a corresponding DER, as further detailed in Section 3 below.

Dollar-Denominated Retention Component Amount: $[___________]

Grant Date: ___________

Reference Date: _____________

Vesting of the Award:

- The Phantom Units (rounded down to the nearest whole number of units, except in the case of the final vesting date) shall vest on each of the following anniversaries of the Reference Date described above, subject to the Participant's continued Service as an Employee through the applicable vesting date, as follows: _______________________________________.
- The Retention Component (rounded down to the nearest whole cent (1¢), except in the case of the final vesting date) shall vest on each of the following anniversaries of the Reference Date described above, subject to the Participant's continued Service as an Employee through the applicable vesting date., as follows: ______________________________________.
- In addition, the Phantom Units and the Retention Component shall be subject to accelerated vesting as set forth in Section 4 below.

Termination of the Award: Except as otherwise described in the Plan or this Agreement, in the event of a termination of the Participant's Service for any reason, all Phantom Units and any portions of the Retention Component that have not vested prior to or in connection with such termination of Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor.

Payment of the Award:

- Vested Phantom Units shall be paid to the Participant in the form of Units and/or cash as set forth in Section 5 below.
- Vested Retention Component amounts shall be paid to the Participant in the form of cash as set forth in Section 5 below.

TERMS AND CONDITIONS OF THE ____ LTIP GRANT

1. Grant. The Company hereby grants to the Participant, as of the Grant Date, that certain Award described in the Grant Notice and consisting of a grant of the Phantom Units and a grant of the Retention Component, subject to all of the terms and conditions contained in this Agreement, the Grant Notice, the Plan and the Time of Settlement Election Form (the "**Election Form**") (if any). Prior to actual payment in respect of any vested Phantom Unit or vested Retention Component amount, such Phantom Unit and Retention Component amount will represent an unsecured obligation of the Partnership, payable (if at all) only from the general assets of the Partnership.

2. LTIP Grant – In General.

(a) *Phantom Units*. Subject to Section 4 below, each Phantom Unit that vests shall represent the right to receive payment, in accordance with Section 5 below, in the form of one (1) Unit. Unless and until a Phantom Unit vests, the Participant will have no right to payment in respect of such Phantom Unit.

(b) *Retention Component*. Subject to Section 4 below, the portion of the Retention Component that vests shall represent the right to receive payment, in accordance with Section 5 below, in the form of cash. Unless and until the applicable Retention Component amount vests, the Participant will have no right to payment of such amount in respect of such vested portion of the Retention Component.

3. Grant of Tandem DER. Each Phantom Unit granted hereunder is hereby granted in tandem with a corresponding DER, which DER shall remain outstanding from the Grant Date until the earlier of the payment or forfeiture of the Phantom Unit to which it corresponds. Each vested DER shall entitle the Participant to receive payments, subject to and in accordance with this Agreement, in an amount equal to any distributions made by the Partnership in respect of the Unit underlying the Phantom Unit to which such DER relates. Such payments shall be made in cash to the extent the corresponding distribution was made in cash and shall be made in accordance with Section 5 below. The Company shall establish, with respect to each Phantom Unit, a separate DER bookkeeping account for such Phantom Unit (a "**DER Account**"), which shall be credited (without interest) on the applicable distribution dates with an amount equal to any distributions made by the Partnership during the period that such Phantom Unit remains outstanding with respect to the Unit underlying the Phantom Unit to which such DER relates. Upon the vesting of a Phantom Unit, the DER (and the DER Account) with respect to such vested Phantom Unit shall also become vested. Similarly, upon the forfeiture of a Phantom Unit, the DER (and the DER Account) with respect to such forfeited Phantom Unit shall also be forfeited. DERs shall not entitle the Participant to any payments relating to distributions occurring after the earlier to occur of the applicable Phantom Unit payment date or the forfeiture of the Phantom Unit underlying such DER. The DERs and any amounts that may become distributable in respect thereof shall be treated separately from the Phantom Units and the rights arising in connection therewith for purposes of Section 409A of the Code (including for purposes of the designation of the time and form of payments required by Section 409A of the Code).

4. Vesting and Termination.

(a) *Vesting*. Subject to Section 4(c) below, the Phantom Units and Retention Component shall vest in such amounts and at such times as are set forth in the Grant Notice above.

(b) *Accelerated Vesting*. Subject to Section 4(c) below, the unvested portions of the Phantom Units and Retention Component shall vest in full upon the occurrence of any of the following events: (i) a termination of the Participant's Service by the Company or the Partnership other than for Cause, (ii) a termination of the Participant's Service by the Participant for Good Reason (as that term shall be defined in a written agreement (if any) between the Company and the Participant), (iii) a termination of the Participant's Service by reason of the Participant's death or Disability, or (iv) a Change in Control.

(c) *Forfeiture*. Notwithstanding the foregoing, in the event of a termination of the Participant's Service for any reason, all Phantom Units and Retention Component amounts that have not vested prior to or in connection with such termination of Service shall thereupon automatically be forfeited by the Participant without further action and without payment of consideration therefor. No portion of the Phantom Units or Retention Component which has not become vested at the date of the Participant's termination of Service shall thereafter become vested.

(d) *Payment*. Vested Phantom Units and vested Retention Component amounts shall be subject to the payment provisions set forth in Section 5 below.

5. Payment of Phantom Units, DERs and Retention Components.

(a) *Phantom Units*. Unpaid, vested Phantom Units shall be paid to the Participant (or in the event of the Participant's death, to the Participant's estate) in the form of Units or in the Company's sole discretion cash, or a combination of both, in an amount equal to the Fair Market Value of a Unit, in a lump-sum as soon as reasonably practical, but not later than forty-five (45) days, following the date on which such Phantom Units vest or, if applicable, at the time elected pursuant to the Election Form.

(b) *DERs*. Unpaid, vested DERs shall be paid to the Participant (or in the event of the Participant's death, to the Participant's estate) as soon as reasonably practical, but not later than forty-five (45) days, following the date on which a Phantom Unit and related DER vests, in the form of a cash payment equal to the amount then credited to the DER Account maintained with respect to such Phantom Unit or, if applicable, at the time elected pursuant to the Election Form.

(c) *Retention Components*. Unpaid, vested Retention Component amounts shall be paid to the Participant (or in the event of the Participant's death, to the Participant's estate) as soon as reasonably practical, but not later than forty-five (45) days, following the date on which the applicable Retention Component amount vests, in the form of a cash payment or, if applicable, at the time elected pursuant to the Election Form.

(c) *Potential Six-Month Delay*. Notwithstanding anything to the contrary in this Agreement, no amounts payable under this Agreement shall be paid to the Participant prior to the expiration of the six (6)-month period following his or her "separation from service" (within the meaning of Treasury Regulation Section 1.409A-1(h)) (a

“**Separation from Service**”) to the extent that the Company determines that paying such amounts prior to the expiration of such six (6)-month period would result in a prohibited distribution under Section 409A(a)(2)(B)(i) of the Code. If the payment of any such amounts is delayed as a result of the previous sentence, then on the first business day following the end of the applicable six (6)-month period (or such earlier date upon which such amounts can be paid under Section 409A of the Code without resulting in a prohibited distribution, including as a result of the Participant’s death), such amounts shall be paid to the Participant.

6. Tax Withholding.

(a) *In General*. The Company and/or its Affiliates shall have the authority and the right to deduct or withhold, or to require the Participant to remit to the Company and/or its Affiliates, an amount sufficient to satisfy all applicable federal, state and local taxes (including the Participant’s employment tax obligations) that become due under applicable law with respect to any taxable event arising in connection with the Award.

(b) *Phantom Unit Matters*. The Company and/or its Affiliates shall have the authority and right to satisfy such withholding amounts from proceeds of the sale of Units acquired upon vesting of the Phantom Units either through a voluntary sale or through a mandatory sale arranged by the Company (on the Participant’s behalf pursuant to this authorization). In satisfaction of the foregoing requirement, unless otherwise determined by the Committee (which determination may not be delegated), the Company and/or its Affiliates shall withhold Units otherwise issuable in respect of such Phantom Units having a Fair Market Value equal to the sums required to be withheld. In the event that Units that would otherwise be issued in payment of the Phantom Units are used to satisfy such withholding obligations, the number of Units which shall be so withheld shall, unless otherwise approved by the Committee, not exceed the number of Units that would result in an accounting charge with respect to such Units used to pay such taxes.

7. Rights as Unit Holder. Neither the Participant nor any person claiming under or through the Participant shall, with respect to any Phantom Units subject to the Award, have any of the rights or privileges of a holder of Units in respect of any Units that may become deliverable hereunder unless and until certificates representing such Units shall have been issued or recorded in book entry form on the records of the Partnership or its transfer agents or registrars, and delivered in certificate or book entry form to the Participant or any person claiming under or through the Participant.

8. Non-Transferability. Neither the Phantom Units, the DERs or the Retention Component nor any right of the Participant thereunder may be assigned, alienated, pledged, attached, sold or otherwise transferred or encumbered by the Participant (or any permitted transferee) other than by will or the laws of descent and distribution and any such purported assignment, alienation, pledge, attachment, sale, transfer or encumbrance shall be void and unenforceable against the Company, the Partnership and any of their Affiliates.

9. Distribution of Units. Unless otherwise determined by the Committee or required by any applicable law, rule or regulation, neither the Company nor the Partnership shall deliver to the Participant, with respect to any payment relating to the Phantom Units under the Award, certificates evidencing Units issued pursuant to this Agreement and instead such Units shall be recorded in the books of the Partnership (or, as applicable, its transfer agent or equity plan administrator). All certificates for any such Units issued pursuant to this Agreement and all

Units issued pursuant to book entry procedures hereunder shall be subject to such stop transfer orders and other restrictions as the Company may deem advisable under the Plan or the rules, regulations, and other requirements of the Securities Exchange Commission, any stock exchange upon which such Units are then listed, and any applicable federal or state laws, and the Company may cause a legend or legends to be inscribed on any such certificates or book entry to make appropriate reference to such restrictions. In addition to the terms and conditions provided herein, the Company may require that the Participant make such covenants, agreements, and representations as the Company, in its sole discretion, deems advisable in order to comply with any such laws, regulations, or requirements. No fractional Units shall be issued or delivered pursuant to the Phantom Units and the Committee shall determine whether cash, other securities, or other property shall be paid or transferred in lieu of fractional Units or whether such fractional Units or any rights thereto shall be canceled, terminated, or otherwise eliminated.

10. Partnership Agreement. Units issued upon payment of the Phantom Units under the Award shall be subject to the terms of the Plan and the Partnership Agreement. Upon the issuance of Units to the Participant, the Participant shall, automatically and without further action on his or her part, (i) be admitted to the Partnership as a Limited Partner (as defined in the Partnership Agreement) with respect to the Units, and (ii) become bound, and be deemed to have agreed to be bound, by the terms of the Partnership Agreement.

11. No Effect on Service. Nothing in this Agreement or in the Plan shall be construed as giving the Participant the right to be retained in the employ or service of the Company or any Affiliate thereof. Furthermore, the Company and its Affiliates may at any time dismiss the Participant from employment or consulting free from any liability or any claim under the Plan or this Agreement, unless otherwise expressly provided in the Plan, this Agreement or any other written agreement between the Participant and the Company or an Affiliate thereof.

12. Severability. If any provision of this Agreement is or becomes or is deemed to be invalid, illegal, or unenforceable in any jurisdiction, such provision shall be construed or deemed amended to conform to the applicable law or, if it cannot be construed or deemed amended without, in the determination of the Committee, materially altering the intent of this Agreement, such provision shall be stricken as to such jurisdiction, and the remainder of this Agreement shall remain in full force and effect.

13. Tax Consultation. None of the Board, the Committee, the Company nor the Partnership has made any warranty or representation to Participant with respect to the income tax consequences that relate to the Award or the transactions contemplated by this Agreement, and the Participant represents that he or she is in no manner relying on such entities or their representatives for tax advice or an assessment of such tax consequences. The Participant understands that the Participant may suffer adverse tax consequences in connection with the Phantom Units, the DERs and the Retention Component granted hereunder. The Participant represents that the Participant has consulted with any tax consultants that the Participant deems advisable in connection with the Award.

14. Amendments, Suspension and Termination. Subject to Section 7(a) of the Plan, the Committee may waive any conditions or rights under, amend any terms of, or alter this Agreement at any time, provided that no such change, other than pursuant to Section 7(c) of the

Plan, shall materially reduce the rights or benefits of the Participant without the Participant's consent.

15. Conformity to Securities Laws. The Participant acknowledges that the Plan and this Agreement are intended to conform to the extent necessary with all provisions of the Securities Act and the Exchange Act, any and all regulations and rules promulgated by the Securities and Exchange Commission thereunder, and all applicable state securities laws and regulations. Notwithstanding anything herein to the contrary, the Plan shall be administered, and the Phantom Units, the DERs and the Retention Component are granted, only in such a manner as to conform to such laws, rules and regulations. To the extent permitted by applicable law, the Plan and this Agreement shall be deemed amended to the extent necessary to conform to such laws, rules and regulations.

16. Code Section 409A. Neither the Award nor any of the payments made pursuant to this Agreement are intended to constitute or provide for a deferral of compensation that is subject to Section 409A of the Code, except to the extent the Participant elects a deferred payment date pursuant to the Election Form. To the extent that the Committee determines that the Award or any such payment is not exempt from (or, if an election is made pursuant to the Election Form, compliant with) Section 409A of the Code, the Committee may (but shall not be required to) amend this Agreement or the Election Form, if applicable, in a manner intended to comply with the requirements of Section 409A of the Code or an exemption therefrom (including amendments with retroactive effect), or take any other actions as it deems necessary or appropriate to (a) exempt the Award or the payments thereunder from Section 409A of the Code and/or preserve the intended tax treatment of the benefits provided with respect to the Phantom Units, the DERs and the Retention Component, or (b) comply with the requirements of Section 409A of the Code. To the extent applicable, this Agreement and the Election Form (if any) shall be interpreted in accordance with the provisions of Section 409A of the Code. Notwithstanding anything in this Agreement or the Election Form (if any) to the contrary, to the extent that any payment or benefit hereunder constitutes non-exempt "nonqualified deferred compensation" for purposes of Section 409A of the Code, and such payment or benefit would otherwise be payable or distributable hereunder by reason of the Participant's termination of Service, all references to the Participant's termination of Service shall be construed to mean a Separation from Service, and the Participant shall not be considered to have a termination of Service unless such termination constitutes a Separation from Service with respect to the Participant.

17. Adjustments; Clawback. The Participant acknowledges that the Award is subject to modification and termination in certain events as provided in this Agreement and Section 7 of the Plan. The Participant further acknowledges that the Award and any payments made hereunder shall be subject to the provisions of any clawback policy that may be adopted as provided in Section 8(o) of the Plan.

18. Successors and Assigns. The Company or the Partnership may assign any of its rights under this Agreement to single or multiple assignees, and this Agreement shall inure to the benefit of the successors and assigns of the Company and the Partnership. Subject to the restrictions on transfer contained herein, this Agreement shall be binding upon the Participant and his or her heirs, executors, administrators, successors and assigns.

19. Governing Law. The validity, construction, and effect of this Agreement and any rules and regulations relating to this Agreement shall be determined in accordance with the laws of the State of Delaware without regard to its conflicts of laws principles.

20. Consent to Jurisdiction and Services of Process; Appointment of Agent. NOTWITHSTANDING ANYTHING TO THE CONTRARY IN THE PARTNERSHIP AGREEMENT, EACH PARTY TO THIS AGREEMENT HEREBY CONSENTS TO THE EXCLUSIVE JURISDICTION OF THE UNITED STATES DISTRICT COURT FOR THE SOUTHERN DISTRICT OF NEW YORK AND OF THE STATE COURTS LOCATED IN THE STATE OF NEW YORK IN NEW YORK COUNTY AND IRREVOCABLY AGREES THAT ALL ACTIONS OR PROCEEDINGS ARISING OUT OF OR RELATING TO THIS AGREEMENT, THE PHANTOM UNITS OR THE RETENTION AWARD, SHALL BE LITIGATED IN SUCH COURTS. EACH PARTY (a) CONSENTS TO SUBMIT HIMSELF, HERSELF OR ITSELF TO THE PERSONAL JURISDICTION OF SUCH COURTS FOR SUCH ACTIONS OR PROCEEDINGS, (b) AGREES THAT HE, SHE OR IT WILL NOT ATTEMPT TO DENY OR DEFEAT SUCH PERSONAL JURISDICTION BY MOTION OR OTHER REQUEST FOR LEAVE FROM ANY SUCH COURT, AND (c) AGREES THAT HE, SHE OR IT WILL NOT BRING ANY SUCH ACTION OR PROCEEDING IN ANY COURT OTHER THAN SUCH COURTS. EACH PARTY ACCEPTS FOR HIMSELF, HERSELF OR ITSELF AND IN CONNECTION WITH SUCH PARTY'S PROPERTIES, GENERALLY AND UNCONDITIONALLY, THE EXCLUSIVE AND IRREVOCABLE JURISDICTION AND VENUE OF THE AFORESAID COURTS AND WAIVES ANY DEFENSE OF FORUM NON CONVENIENS, AND IRREVOCABLY AGREES TO BE BOUND BY ANY NON-APPEALABLE JUDGMENT RENDERED THEREBY IN CONNECTION WITH SUCH ACTIONS OR PROCEEDINGS. A COPY OF ANY SERVICE OF PROCESS SERVED UPON THE PARTIES SHALL BE MAILED BY REGISTERED MAIL TO THE RESPECTIVE PARTY EXCEPT THAT, UNLESS OTHERWISE PROVIDED BY APPLICABLE LAW, ANY FAILURE TO MAIL SUCH COPY SHALL NOT AFFECT THE VALIDITY OF SERVICE OF PROCESS. IF ANY AGENT APPOINTED BY A PARTY REFUSES TO ACCEPT SERVICE, EACH PARTY AGREES THAT SERVICE UPON THE APPROPRIATE PARTY BY REGISTERED MAIL SHALL CONSTITUTE SUFFICIENT SERVICE. NOTHING HEREIN SHALL AFFECT THE RIGHT OF A PARTY TO SERVE PROCESS IN ANY OTHER MANNER PERMITTED BY LAW.

21. Headings. Headings are given to the sections and subsections of this Agreement solely as a convenience to facilitate reference. Such headings shall not be deemed in any way material or relevant to the construction or interpretation of this Agreement or any provision hereof.

[*Signature page follows*]

The Participant's signature below indicates the Participant's agreement with and understanding that the Award is subject to all of the terms and conditions contained in the Plan, in this Agreement, the Grant Notice and in the Election Form (if any), and that, in the event that there are any inconsistencies between the terms of the Plan and the terms of this Agreement, the terms of the Plan shall control. The Participant further acknowledges that the Participant has read and understands the Plan, this Agreement and the Election Form (if any), which contain the specific terms and conditions of the Award. The Participant hereby agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee upon any questions arising under the Plan, this Agreement, the Grant Notice or the Election Form (if any).

SUMMIT MIDSTREAM GP, LLC,
a Delaware limited liability company

By: J. Heath Deneke
Its: General Partner

By: ________________________________
Name: J. Heath Deneke
Title: President and Chief Executive Officer

SUMMIT MIDSTREAM PARTNERS, LP,
a Delaware limited partnership

By: Summit Midstream GP, LLC
Its: General Partner

By:________________________________
Name: J. Heath Deneke
Title: President and Chief Executive Officer

"**PARTICIPANT**"

____
[Name]

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-234781 on Form S-3 and Nos. 333-184214, 333-189684 and 333-237323 on Form S-8 of our reports dated February 28, 2022, relating to the consolidated financial statements of Summit Midstream Partners, LP and subsidiaries (the “Partnership”), and the effectiveness of the Partnership's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Summit Midstream Partners, LP for the year ended December 31, 2021.

DELOITTE & TOUCHE LLP

Houston, Texas

February 28, 2022

EXHIBIT 31.1

CERTIFICATIONS

I, Heath Deneke, certify that:

1. I have reviewed this annual report on Form 10-K of Summit Midstream Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	February 28, 2022	*/s/ Heath Deneke*
		Heath Deneke
		President, Chief Executive Officer and Director of Summit Midstream GP, LLC (the general partner of Summit Midstream Partners, LP)

EXHIBIT 31.2

CERTIFICATIONS

I, William J. Mault, certify that:

1. I have reviewed this annual report on Form 10-K of Summit Midstream Partners, LP;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date:	February 28, 2022	*/s/ William J. Mault*
		William J. Mault
		Executive Vice President and Chief Financial Officer of Summit Midstream GP, LLC (the general partner of Summit Midstream Partners, LP)

EXHIBIT 32.1

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report on Form 10-K of Summit Midstream Partners, LP (the "Registrant") for the annual period ended December 31, 2021, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, Heath Deneke, as President, Chief Executive Officer and Director of Summit Midstream GP, LLC, the general partner of the Registrant, and William J. Mault, as Executive Vice President and Chief Financial Officer of Summit Midstream GP, LLC, the general partner of the Registrant, each hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to his knowledge:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Registrant.

/s/ Heath Deneke

Name:	Heath Deneke
Title:	President, Chief Executive Officer and Director of Summit Midstream GP, LLC (the general partner of Summit Midstream Partners, LP)
Date:	February 28, 2022

/s/ William J. Mault

Name:	William J. Mault
Title:	Executive Vice President and Chief Financial Officer of Summit Midstream GP, LLC (the general partner of Summit Midstream Partners, LP)
Date:	February 28, 2022