UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☒

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2020

OR

☐

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to .
Commission File Number 001-33147

Evolve Transition Infrastructure LP

(Exact Name of Registrant as Specified in Its Charter)

Delaware **(State of organization)**	**11-3742489** **(I.R.S. Employer Identification No.)**
1360 Post Oak Blvd, Suite 2400 **Houston, Texas** **(Address of Principal Executive Offices)**	**77056** **(Zip Code)**

(713) 783-8000
(Registrant's Telephone Number, Including Area Code)

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Units representing limited partner interests	SNMP	NYSE American

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. Yes ☐ No ☒

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☒ Smaller reporting company ☒ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant 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 Exchange Act) Yes ☐ No ☒

The aggregate market value of Evolve Transition Infrastructure LP common units held by non-affiliates as of June 30, 2020 was approximately $4,070,736 based upon the NYSE American closing price as of such date.

Common units outstanding on March 15, 2021: 54,533,593 common units.

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COMMONLY USED DEFINED TERMS

As used in this Annual Report on Form 10-K (this "Form 10-K"), unless the context indicates or otherwise requires, the following terms have the following meanings:

- "Evolve Transition Infrastructure," "the Partnership," "we," "us," "our" or like terms refer collectively to Evolve Transition Infrastructure LP, its consolidated subsidiaries and, where the context provides, the entities in which we have a 50% ownership interest.
- "Bbl" means one barrel of 42 U.S. gallons of oil.
- "Board" means the board of directors of our general partner.
- "Boe" means one barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.
- "Boe/d" means one Boe per day.
- "Class C Preferred Units" means our Class C Preferred Units representing limited partner interests in Evolve Transition Infrastructure.
- "common units" means our common units representing limited partner interests in Evolve Transition Infrastructure.
- "Credit Agreement" means collectively, the Third Amended and Restated Credit Agreement, dated as of March 31, 2015, among the Partnership, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto, as amended by (i) Amendment and Waiver of Third Amended and Restated Credit Agreement, dated as of August 12, 2015, (ii) Joinder, Assignment and Second Amendment to Third Amended and Restated Credit Agreement, dated as of October 14, 2015, (iii) Third Amendment to Third Amended and Restated Credit Agreement, dated as of November 12, 2015, (iv) Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of July 5, 2016, (v) Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of April 17, 2017, (vi) Sixth Amendment to Third Amended and Restated Credit Agreement, dated as of November 7, 2017, (vii) Seventh Amendment to Third Amended and Restated Credit Agreement, dated as of February 5, 2018, (viii) Eighth Amendment to Third Amended and Restated Credit Agreement, dated as of May 7, 2018, (ix) Ninth Amendment to Third Amended and Restated Credit Agreement, dated as of November 22, 2019, and (x) Tenth Amendment to Third Amended and Restated Credit Agreement, dated as of November 6, 2020 (individually, the "Tenth Amendment").
- "GHGs" mean greenhouse gases.
- "MBbl" means one thousand barrels of oil or other liquid hydrocarbons.
- "MBbl/d" means one thousand barrels of oil or other liquid hydrocarbons per day.
- "MBoe" means one thousand Boe.
- "Mcf" means one thousand cubic feet of natural gas.
- "Mesquite" means (i) at all times prior to June 30, 2020, Sanchez Energy Corporation and its consolidated subsidiaries, and (ii) at all times after and including June 30, 2020, Mesquite Energy, Inc. and its consolidated subsidiaries.
- "MMBbl" means one million barrels of oil or other liquid hydrocarbons.
- "MMBoe" means one million Boe.

- "MMBtu" means one million British thermal units.
- "MMcf" means one million cubic feet of natural gas.
- "MMcf/d" means one million cubic feet of natural gas per day.
- "NGLs" means the combination of ethane, propane, butane, natural gasolines and other components that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.
- "Operational Services Agreement" means that certain Services Agreement, effective as of November 1, 2020, between the Partnership, SEP Holdings IV, LLC, Catarina Midstream, LLC, SECO Pipeline and SNMP Services.
- "our general partner" means Evolve Transition Infrastructure GP LLC, our general partner.
- "our partnership agreement" means the Third Amended and Restated Agreement of Limited Partnership of the Partnership, dated as of August 2, 2019, as amended by the Stonepeak Letter Agreement (as defined herein), as amended by Amendment No. 1 thereto, dated as of February 12, 2021.
- "Shared Services Agreement" means the Amended and Restated Shared Services Agreement between SP Holdings and the Partnership, dated as of March 6, 2015.
- "Settlement Agreement" means the Settlement Agreement, dated June 6, 2020, as amended by that certain Amendment Agreement, dated as of June 14, 2020 and effective as of June 6, 2020, in each case, by and among the Partnership, our general partner, Catarina Midstream, LLC, Seco Pipeline, LLC, the SN Debtors, SP Holdings, Carnero G&P LLC and TPL SouthTex Processing Company LP.
- "SN Debtors" means collectively, Mesquite, SN Palmetto, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, Rockin L Ranch Company, LLC, SN Payables, LLC, SN EF Maverick, LLC and SN UR Holdings, LLC.
- "SNMP Services" means SNMP Services Inc., our wholly owned subsidiary which provides payroll, human resources, employee benefits and other consulting services to us and our subsidiaries.
- "SP Holdings" means SP Holdings, LLC, the sole member of our general partner.
- "Stonepeak" means Stonepeak Catarina and its subsidiaries, other than the Partnership.
- "Stonepeak Catarina" means Stonepeak Catarina Holdings, LLC.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Form 10-K contains "forward-looking statements" as defined by the United States Securities and Exchange Commission (the "SEC") that are subject to a number of risks and uncertainties, many of which are beyond our control. These statements may include discussions about our business strategy; the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements; our financing strategy; our acquisition strategy; our ability to make distributions; our future operating results; the ability of our partners to perform under our joint ventures; our future capital expenditures; and our plans, objectives, expectations, forecasts, outlook and intentions.

All of these types of statements, other than statements of historical fact included in this Form 10-K, are forward-looking statements. These forward-looking statements may be found in Part II, Item 7. and other items within this Form 10-K. In some cases, forward-looking statements can be identified by terminology such as "may," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "potential," "pursue," "target," "continue," the negative of such terms or other comparable terminology.

The forward-looking statements contained in this Form 10-K are largely based on our expectations, which reflect estimates and assumptions made by the management of our general partner. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management's assumptions about future events may prove to be inaccurate.

Important factors that could cause our actual results to differ materially from the expectations reflected in the forward-looking statements include, among others:

- the resolution of the pending Rejection Lawsuits (as defined below) and their impact on the effectiveness of the Settlement Agreement and our business, results of operations and financial condition;
- our ability to successfully execute our business, acquisition and financing strategies;
- changes in general economic conditions, including market and macro-economic disruptions resulting from the ongoing pandemic caused by a novel strain of coronavirus ("COVID-19") and related governmental responses;
- the ability of our customers to meet their drilling and development plans on a timely basis, or at all, and perform under gathering, processing and other agreements;
- the creditworthiness and performance of our counterparties, including financial institutions, operating partners, customers and other counterparties;
- our ability to extend, replace or refinance our Credit Agreement;
- our ability to grow enterprise value;
- the ability of our partners to perform under our joint ventures;
- the availability, proximity and capacity of, and costs associated with, gathering, processing, compression and transportation facilities;
- our ability to access the credit and capital markets to obtain financing on terms we deem acceptable, if at all, and to otherwise satisfy our capital expenditure requirements;
- the timing and extent of changes in prices for, and demand for, natural gas, NGLs and oil;
- our ability to successfully execute our hedging strategy and the resulting realized prices therefrom;

- the accuracy of reserve estimates, which by their nature involve the exercise of professional judgment and may, therefore, be imprecise;
- competition in the oil and natural gas industry for employees and other personnel, equipment, materials and services and, related thereto, the availability and cost of employees and other personnel, equipment, materials and services;
- the extent to which our assets operated by others are operated successfully and economically;
- our ability to compete with other companies in the oil and natural gas industry;
- the impact of, and changes in, government policies, laws and regulations, including tax laws and regulations, environmental laws and regulations relating to air emissions, waste disposal, hydraulic fracturing and access to and use of water, laws and regulations imposing conditions and restrictions on drilling and completion operations and laws and regulations with respect to derivatives and hedging activities;
- the use of competing energy sources and the development of alternative energy sources;
- unexpected results of litigation filed against us;
- disruptions due to extreme weather conditions, such as extreme rainfall, hurricanes or tornadoes;
- the extent to which we incur uninsured losses and liabilities or losses and liabilities in excess of our insurance coverage; and
- the other factors described under "Part I, Item 1A. Risk Factors" in this Form 10-K and any updates to those factors set forth in our subsequent Quarterly Reports on Form 10-Q or Current Reports on Form 8-K.

Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or the forward-looking events and circumstances will occur. Actual results may differ materially from those anticipated or implied in forward-looking statements. The forward-looking statements speak only as of the date made, and other than as required by law, we do not intend to publicly update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

Item 1. Business

Overview

We are a publicly-traded limited partnership formed in 2005 focused on the acquisition, development and ownership of infrastructure critical to the transition of energy supply to lower carbon sources. We own natural gas gathering systems, pipelines, and processing facilities in South Texas and continue to pursue energy transition infrastructure opportunities. Our common units are currently listed on the NYSE American under the symbol "SNMP."

On February 26, 2021, in connection with our management team's focus on expanding our business strategy to focus on the ongoing energy transition in the industries in which we operate, we changed our name to Evolve Transition Infrastructure LP and our general partner changed its name to Evolve Transition Infrastructure GP LLC.

COVID-19

In March 2020, the World Health Organization declared COVID-19 a pandemic and recommended containment and mitigation measures worldwide and the United States declared a national emergency with respect to COVID-19. As a result, extraordinary and wide-ranging actions were taken by international, federal, state and local public health and governmental authorities to reduce the spread of COVID-19, including quarantines, government restrictions on movement, business closures and suspensions, canceled events and activities, self-isolation, and other voluntary or mandated changes in behavior. Such actions have also resulted in significant business and operational disruptions, including supply chain disruptions, travel restrictions, stay-at-home orders and limitations on the availability of workforces. COVID-19 and the ongoing response to mitigate its impact have contributed to a massive economic shutdown and decreased demand for crude oil and natural gas.

Also in the first quarter of 2020, Saudi Arabia and Russia increased production of crude oil as the two countries competed for market share. As a result, the global supply of crude oil significantly exceeded demand and led to a collapse in crude oil prices. The collapse in crude oil prices and the related impact on crude oil drilling resulted in crude oil, natural gas and NGL production being curtailed in the second quarter of 2020.

While crude oil prices have started to rebound from the lows reached during the early stages of the COVID-19 pandemic, the volatility in oil prices and impact of the Mesquite Chapter 11 Case (as defined below) have caused a negative impact on our net cash flows during the year ended December 31, 2020. If Mesquite should decide to shut-in any of the wells connected to our midstream facilities or otherwise becomes unable to make future payments under the Gathering Agreement, it could have a material and adverse impact on our business. The full extent to which the COVID-19 pandemic impacts our business and operations will depend on the severity, location and duration of the effects and spread of COVID-19, the actions undertaken by national, regional and local governments and health officials to contain the virus or treat its effects, and how quickly and to what extent economic conditions improve and normal business and operating conditions resume. Please read "Part I, Item 1A. Risk Factors."

Mesquite Bankruptcy – Settlement Agreement and Rejection Lawsuits

On August 11, 2019, the SN Debtors filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy code in the Bankruptcy Court, jointly administered under Case No. 19-34508 (the "Mesquite Chapter 11 Case").

On June 6, 2020 the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, including but not limited to, (i) Amendment No. 2 to the Gathering Agreement ("Amendment No. 2"),(ii) that certain Firm Transportation Service Agreement, dated as of June 30, 2020, by and between Seco Pipeline, LLC and SN Catarina, LLC, a wholly owned subsidiary of Mesquite (the "Seco Catarina Agreement"), and (iii) that certain Firm Transportation Service Agreement, dated as of June 30, 2020, by and between Seco Pipeline, LLC and SN EF Maverick, LLC, a wholly owned subsidiary of

Mesquite (the "Seco Comanche Agreement"). Each such agreement will become effective only upon satisfaction of certain closing conditions described in the Settlement Agreement.

On June 23, 2020, certain affiliates of each Occidental Petroleum Corp., The Blackstone Group and GSO Capital Partners each filed a complaint (collectively, the "Rejection Lawsuits") against Mesquite and certain of its subsidiaries requesting, among other things, that the Bankruptcy Court not approve the rejection of certain commercial agreements, as set forth in the Settlement Agreement, in connection with Mesquite's Comanche Asset (as defined herein).

On June 30, 2020, the SN Debtors emerged from the Mesquite Chapter 11 Case, with Mesquite becoming a privately held corporation.

The commercial agreements contemplated by the Settlement Agreement will not become effective until, among other things, the Rejection Lawsuits have been resolved in favor of the SN Debtors and the Bankruptcy Court has approved the rejection of the certain commercial agreements underlying the Rejection Lawsuits. The Rejection Lawsuits were not resolved by October 1, 2020, and as a result the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms. To date, none of the parties of the Settlement Agreement have provided notice of termination.

Our Relationship with Stonepeak

Since October 14, 2015, Stonepeak Catarina has owned all of our issued and outstanding preferred units. As of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) a warrant (the "Warrant") that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights. Stonepeak also owns 100% of the issued and outstanding equity interests in SP Holdings, which is the sole member of our general partner. SP Holdings has the right to appoint all of the members of the Board of directors other than two directors which Stonepeak Catarina is entitled to designate pursuant to that certain Amended and Restated Board Representation and Standstill Agreement, dated as of August 2, 2019. As a result of the foregoing, Stonepeak controls us and our general partner and has the ability to appoint all of the members of the Board.

Stonepeak Catarina is indirectly managed by Stonepeak Partners LP, a leading North American infrastructure private equity firm ("Stonepeak Partners"). Stonepeak Partners' significant infrastructure and midstream energy expertise and deep financial resources are reflected in over $31 billion of assets under management, with investments to date including, among others, preferred and common interests in the Partnership, MPLX LP, Phillips 66 Partners LP, Plains All American Pipeline, L.P. and Targa Resources Corp. We believe that, as a result of Stonepeak's significant ownership interest in us, Stonepeak is incentivized to support and promote our business plan and to encourage us to pursue projects that enhance the overall value of our business. While our relationship with Stonepeak is a significant strength, it is also a source of potential risks and conflicts. Please read "Part I, Item 1A. Risk Factors—Risks Inherent in an Investment in Our Common Units" and "Part III, Item 13. Certain Relationships and Related Transactions, and Director Independence."

Business Strategy

Our primary business objective is to create long-term value by generating stable and predictable cash flows that allow us to reduce the amount of our indebtedness and pursue energy transition infrastructure opportunities. We plan to achieve this objective by executing the following business strategy:

- grow our business through the acquisition and development of infrastructure critical to the transition of energy supply to lower carbon sources;
- pursue organic investments in our existing operating areas to support growth;
- pursue strategic relationships with third-party producers and other companies with operations in the area in which we operate in order to maximize the utilization of our midstream facilities or provide other revenue-generating services; and

● maintain financial flexibility and a strong capital structure.

Business Segments

Our business activities are conducted under two operating segments for which we provide information in our consolidated financial statements for the years ended December 31, 2020 and 2019. These two segments are based on the nature of the operations that are undertaken by each segment and are our:

● midstream business, which includes Western Catarina Midstream, the Carnero JV and Seco Pipeline (each as defined below); and

● production business, which includes non-operated oil and natural gas interests located in the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana.

For information about our segments' revenues, profits and losses and total assets, see Note 17 "Reporting Segments" of our Notes to Consolidated Financial Statements.

Midstream Business

Western Catarina Midstream

In October 2015, we acquired (the "Catarina Transaction") a gathering system from Mesquite ("Western Catarina Midstream"), which is located on the western portion of Mesquite's acreage position in Dimmit, La Salle and Webb counties in Texas (such net acreage is collectively referred to herein as "Mesquite's Catarina Asset," and the western portion of such net acreage is individually referred to herein as "Western Catarina"). Western Catarina Midstream consists of approximately 160 miles of gathering pipelines, four main processing and gathering facilities, including stabilizers, storage tanks, compressors and dehydration units, and other related assets in Western Catarina, which are located in Dimmit and Webb counties in Texas, and services upstream production from assets located in the Eagle Ford Shale in South Texas. The gathering lines range in diameter from four to 12 inches, with a capacity of 200 MMcf/d for natural gas, and 40 MBbl/d for crude oil and NGLs. There are four main gathering and processing facilities, which includes eight stabilizers of 5,000 Bbls/d, approximately 25,000 Bbls of storage capacity, pressurized storage for NGLs, approximately 23,000 horsepower of compression and approximately 300 MMcf/d of dehydration capacity. The gathering system is currently used solely to support the gathering, processing and transportation of natural gas, NGLs and crude oil produced by Mesquite at Mesquite's Catarina Asset. The gathering system has oil interconnects with the Plains All American Pipeline, L.P. header system delivered to the Gardendale terminal, and to all four takeaway pipelines to Corpus Christi, and natural gas interconnects with Southcross Energy Partners, L.P., Kinder Morgan Inc., Energy Transfer Operating, L.P. and Targa Resources Corp.

In conjunction with the Catarina Transaction, we entered into a 15-year firm gas gathering and processing agreement with Mesquite, pursuant to which Mesquite agreed to tender all of its crude oil, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres in Western Catarina for processing and transportation through Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the "Gathering Agreement").

All of the revenues from Western Catarina Midstream are currently earned from Mesquite. Under the Gathering Agreement, Mesquite was contractually obligated to meet a minimum quarterly volume delivery commitment for oil and natural gas, subject to certain adjustments, however, this contractual requirement expired in 2020. In addition, Mesquite is required to pay contractually agreed upon gathering and processing fees for oil and natural gas volumes tendered through Western Catarina Midstream. In June 2017, the Gathering Agreement was amended to add an incremental infrastructure fee to be paid by Mesquite based on water that was delivered to Western Catarina Midstream through March 31, 2018. Since March 31, 2018, we have agreed with Mesquite to continue adding the incremental infrastructure fee on a month-to-month basis.

During the year ended December 31, 2020, Mesquite transported average daily production through Western Catarina Midstream of approximately 7.4 MBbls/d of oil, 93.6 MMcf/d of natural gas and 3.1 MBbls/d of water. The average age of the Western Catarina Midstream assets is approximately nine years, and such assets have an average expected life of approximately 20 additional years.

Carnero JV

In May 2018, we executed a series of agreements with Targa Resources Corp. (NYSE: TRGP) ("Targa") and other parties pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering, LLC ("Carnero Gathering") and Carnero Processing, LLC ("Carnero Processing") (the "Carnero JV Transaction") to form an expanded 50 / 50 joint venture in South Texas, Carnero G&P, LLC ("Carnero JV"), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant located in Bee County, Texas ("Silver Oak II"), to Carnero JV, which expanded the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the 45 miles of high pressure natural gas gathering pipelines owned by Carnero Gathering that connect Western Catarina Midstream to nearby pipelines and the Raptor Gas Processing Facility (the "Carnero Gathering Line") to Carnero JV resulting in the joint venture owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) Carnero JV received a new dedication from Mesquite and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Mesquite's acreage in Dimmit, Webb, La Salle, Zavala and Maverick counties in Texas (such acreage is collectively referred to herein as "Mesquite's Comanche Asset") pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Mesquite, which was approved by all of the unaffiliated Comanche non-operated working interest owners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the joint ventures limited by the capacity of the 260 MMcf/d cryogenic natural gas processing plant in La Salle County, Texas (the "Raptor Gas Processing Facility").

Seco Pipeline

In August 2017, we completed construction of a 100% owned and operated 30-mile natural gas pipeline with 400 MMcf/d capacity that is designed and used to transport dry gas from the Raptor Gas Processing Facility to multiple markets in South Texas (the "Seco Pipeline"). The Seco Pipeline provides upstream producers with optionality to southern gas markets and creates the potential to export natural gas to premium priced markets in Mexico. On September 1, 2017, we entered into a firm transportation service agreement with Mesquite to transport certain quantities of Mesquite's natural gas on a firm basis through the Seco Pipeline for $0.22 per MMBtu delivered on or after September 1, 2017 (the "Seco Pipeline Transportation Agreement"). The Seco Pipeline Transportation Agreement had an initial term of one month and renewed automatically on a month-to-month basis. Mesquite terminated the Seco Pipeline Transportation Agreement effective February 12, 2020. From January 1, 2020 through February 12, 2020, the effective date of the Seco Pipeline Transportation Agreement termination, Mesquite transported an insignificant amount of gas through the Seco Pipeline. The Seco Pipeline has an expected life of approximately 40 years.

Title to Properties

Title to Western Catarina Midstream and the Seco Pipeline assets are either owned in fee or derived from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities, permitting the use of such land for our operations. We have no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license that is held by us or to the title to any material lease, easement, right-of-way, permit or lease we own, and we believe that we have satisfactory title to all of the material leases, easements, rights-of-way, permits and licenses with respect to all Western Catarina Midstream and Seco Pipeline assets.

Production Business

Our total estimated proved reserves at December 31, 2020, were approximately 2.3 MMBoe, all of which were classified as proved developed, with 13% being natural gas, 12% being NGLs, and 75% being oil. At December 31, 2020, we owned approximately 47 net producing wells. Our total average proved reserve-to-production ratio is approximately 9 years and our portfolio decline rate is 11% based on our estimated proved reserves at December 31, 2020.

Below is a description of our operations and our oil and natural gas properties by basin at December 31, 2020:

Locations

All of our reserves were located in the Eagle Ford Shale on non-operated properties. Production during the year ended December 31, 2020 on these properties was 237.7 MBoe and approximately 2,283.4 MBoe of estimated proved reserves were held at December 31, 2020. All of these reserves were classified as proved developed, with 13% being natural gas, 12% being NGLs, and 75% being oil.

We also own non-operated properties in Louisiana. During the year ended December 31, 2020, production on Louisiana properties was 3.5 MBoe.

Operations

We do not currently operate any of our production assets. The Eagle Ford Shale properties are operated by either Sanchez Oil & Gas Corporation ("SOG"), Mesquite or Marathon Oil Company and the Louisiana properties are operated by another prudent operator.

Proved Reserves of Natural Gas, NGLs, and Oil

The following table reflects our estimates for proved natural gas, NGLs and oil reserves based on the SEC definitions that were used to prepare our financial statements for the periods presented. The standardized measure values shown in the table are not intended to represent the current market values of our estimated proved reserves.

	2020	2019
Estimated proved reserves:		
Oil (MBbl)	1,716	2,241
Natural gas (Mcf)	1,722	2,088
NGLs (MBbl)	280	410
Total proved reserves (MBoe)	2,283	2,999
Estimated proved developed reserves:		
Oil (MBbl)	1,716	2,241
Natural gas (Mcf)	1,722	2,088
NGLs (MBbl)	280	410
Total proved developed reserves (MBoe)	2,283	2,999
Proved developed reserves as a percent of total reserves	100%	100%
Standardized measure ($ in millions)[(a)]	$ 11,881	$ 38,350

(a) Standardized measure is the present value of estimated future net revenues to be generated from the production of proved reserves. It is determined using SEC-required prices and costs in effect as of the time of estimation without giving effect to non-property related expenses (such as general and administrative expenses or debt service costs) and discounted using an annual discount rate of 10%. Our standardized measure does not include the impact of derivative transactions or future federal income taxes because we are not subject to federal income taxes. Future prices received for production and costs may vary, perhaps significantly, from the prices and costs assumed for purposes of these estimates. The standardized measure shown should not be considered the current market value of our reserves. The 10% discount factor used to calculate present value, which is required, is not necessarily the most appropriate discount rate. The present value, no matter what discount rate is used, is materially affected by assumptions as to timing of future production, which may prove to be inaccurate. Please read "Part I, item 1A. Risk Factors."

Our 2020 estimates of total proved reserves decreased 716 MBoe from 2019 due to production and revisions of previous estimates of 241 MBoe and 475 MBoe, respectively.

As of December 31, 2020, we had no remaining proved undeveloped reserves in our reserves base.

We expect to make minimal capital expenditures related to recompletion of existing wells during the year ending December 31, 2021.

At December 31, 2020 and December 31, 2019, Ryder Scott Co. LP ("Ryder Scott"), an independent oil and natural gas engineering firm, prepared estimates of all our proved reserves. We used these estimates of our proved reserves to prepare our financial statements. Ryder Scott maintains a degreed staff of highly competent technical personnel. The average experience level of Ryder Scott's technical staff of engineers, geoscientists and petrophysicists exceeds 20 years, including five to 15 years with a major oil company. The engineering information presented in their report was overseen by Mr. Eric Nelson, P.E. Mr. Nelson is an experienced reservoir engineer having been a practicing petroleum engineer since 2002. He has more than 14 years of experience in reserves evaluation with Ryder Scott. He has a Bachelor of Science degree in Chemical Engineering from the University of Tulsa and Master of Business Administration degree from the University of Texas. Mr. Nelson is a Registered Professional Engineer in the State of Texas. Our activities with Ryder Scott are coordinated by a reservoir engineer employed by us who has approximately 41 years of experience in the oil and natural gas industry and an engineering degree from the University of Tennessee and a Master of Business Administration from the University of New Orleans. He is a licensed petroleum engineer in the state of Texas and a member of the Society of Petroleum Engineers. He has prior reservoir engineering and reserves management experience at Exxon Mobil Corporation, Dominion Resources and Hilcorp Energy. He has extensive experience in managing oil and natural gas reserves processes. He serves as the key technical person reviewing the reserve reports prepared by Ryder Scott prior to review by the Audit Committee and approval by the Board.

Production and Price History

The following table sets forth information regarding net production of natural gas, NGLs and oil and certain price and cost information for each of the periods indicated:

	Years Ended December 31,			
	2020	**2019**	**Variance**	
Net production:				
Natural gas (MMcf)	158	231	(73)	(32)%
Oil production (MBbl)	191	228	(37)	(16)%
NGLs (MBbl)	24	42	(18)	(43)%
Total production (MBoe)	241	309	(68)	(22)%
Average daily production (Boe/d)	658	847	(189)	(22)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 4.13	$ 2.24	$ 1.89	84%
Natural gas price per Mcf without hedge settlements	$ 2.15	$ 1.84	$ 0.32	17%
Oil price per Bbl with hedge settlements	$ 51.68	$ 62.94	$ (11.26)	(18)%
Oil price per Bbl without hedge settlements	$ 36.87	$ 59.40	$ (22.53)	(38)%
NGL price per Bbl without hedge settlements	$ 10.58	$ 12.83	$ (2.25)	(18)%
Total price per Boe with hedge settlements	$ 44.72	$ 49.86	$ (5.14)	(10)%
Total price per Boe without hedge settlements	$ 31.68	$ 46.94	$ (15.26)	(33)%
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 23.45	$ 21.04	$ 2.41	11%
Lease operating expenses	$ 22.16	$ 19.03	$ 3.13	16%
Production taxes	$ 1.29	$ 2.01	$ (0.72)	(36)%
Depreciation, depletion and amortization	$ 9.20	$ 12.76	$ (3.55)	(28)%

(a) Field operating expenses include lease operating expenses and production taxes.

Existing Wells

The following table sets forth information at December 31, 2020, relating to the existing wells in which we owned a working interest as of that date. Gross wells are the total number of producing wells in which we have an interest, and net wells are the sum of our fractional working interests owned in gross wells.

	Natural Gas		**Oil**	
	Gross	**Net**	**Gross**	**Net**
Operated	—	—	—	—
Non-operated	—	—	91	47
Total	—	—	91	47

We did not convert any proved undeveloped wells into proved producing wells in 2020.

Drilling Activity

With respect to oil and natural gas wells drilled and completed during the years ended December 31, 2020 and 2019, the information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that are capable of producing commercial quantities of oil or natural gas, regardless of whether they produce a reasonable rate of return. No exploratory wells were drilled on any of our properties during the years ended December 31, 2020 or 2019. During the years ended December 31, 2020 and 2019, there were no wells drilled and there were no wells in progress.

Developed and Undeveloped Acreage

The following table sets forth information related to our leasehold acreage as of December 31, 2020.

	Developed Acreage[a]		**Undeveloped Acreage[b]**	
	Gross[c]	**Net[d]**	**Gross[c]**	**Net[d]**
Total	702	140	—	—

(a) Developed acres are acres pooled within or assigned to productive wells/units.
(b) Undeveloped acres are acres on which wells have not been drilled or acres that have not been pooled into a productive unit.
(c) A gross acre is an acre in which a working interest is either fully or partially leased. The number of gross acres may include minerals not under lease as a result of leasing some but not all joint mineral owners under any given tract.
(d) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Leases

Most of our reserves are comprised of wellbore rights only. We have a small lease position of less than 150 net acres in Louisiana.

Marketing and Major Customers

Our oil and natural gas production in Texas and Louisiana is marketed by the operators of our properties.

Mesquite accounted for 80% and 86% of our total revenue for the years ended December 31, 2020 and 2019, respectively. We are highly dependent upon Mesquite as our most significant customer, and we expect to derive a substantial portion of our revenue from Mesquite in the foreseeable future. Accordingly, we are indirectly subject to the business risks of Mesquite. Any development that materially and adversely affects Mesquite’s operations or financial condition could have a material adverse impact on us. For additional information on the risks associated with our relationship with Mesquite, please read “Part I, Item 1A. Risk Factors.”

Markets and Competition

We operate in a competitive environment for acquiring properties, marketing oil, NGLs and natural gas and retaining trained personnel. Many of our competitors have substantially greater financial, technical and personnel resources than us. As a result, our competitors may be able to outbid us for assets, more competitively price their gathering and transportation services and oil and natural gas production, or utilize superior technical resources than our financial or personnel resources permit. Our ability to acquire additional assets will depend on our ability to evaluate and select suitable assets and to consummate transactions in a competitive environment.

The natural gas gathering, compression, treating and transportation business is very competitive. Upon such time that we seek to obtain customers in addition to Mesquite for Western Catarina Midstream, our competitors will include other midstream companies, producers and intrastate and interstate pipelines. Competition for volumes is primarily based on reputation, commercial terms, reliability, service levels, location, available capacity, capital expenditures and fuel efficiencies.

Stonepeak is not restricted from competing with us. Please read "Part I, Item 1A. Risk Factors—Stonepeak Catarina and its affiliates, including our general partner, will have conflicts of interest with us. They will not owe any fiduciary duties to us or our common unitholders, but instead will owe us and our common unitholders limited contractual duties, and they may favor their own interests to the detriment of us and our other common unitholders." Additional information regarding our relationship with Stonepeak is provided in "Part III, Item 13. Certain Relationships and Related Transactions, and Director Independence."

Governmental Regulation

Environmental Laws

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- restrict the types, quantities and concentrations of various substances, including water and waste, that can be released into the environment;
- limit or prohibit activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible in the absence of such regulations. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. In addition, federal, state and local authorities frequently revise environmental laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

Environmental laws and regulations that could have a material impact on the oil and natural gas industry and our operations include the following:

Waste Handling

The Resource Conservation and Recovery Act ("RCRA") and comparable state laws regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous wastes and non-hazardous wastes. With the approval of the federal Environmental Protection Agency ("EPA"), the individual states can administer some or all of the provisions of RCRA, and some states have adopted their own, more stringent requirements. Drilling fluid, produced water and most other wastes associated with the exploration, development and production of oil and natural gas are currently regulated under RCRA's non-hazardous waste provisions. Although we do not believe that the current costs of managing any of our wastes are material under presently applicable laws, any future reclassification of oil and natural gas exploration, development and production wastes as hazardous wastes, could increase our costs to manage and dispose of wastes.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also known as the Superfund law, can impose joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons can include the owners or operators of the site where the release occurred, and anyone who disposed of, or arranged for the disposal of, a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, including response costs, alternative water supplies, damages to natural resources and the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Each state also has environmental cleanup laws analogous to CERCLA.

We currently own, lease or operate numerous properties that have been used for oil and natural gas production for a number of years. Although we believe that operating and waste disposal practices utilized in the past with respect to these properties were typical for the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, these properties have been operated by third parties or by previous owners or operators whose practices, including the treatment and disposal or release of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future environmental harm.

Water Discharges

The Federal Water Pollution Control Act (the "Clean Water Act"), and comparable state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, impose investigatory or remedial obligations and issue injunctions limiting or preventing our operations for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Oil Pollution Act

The Oil Pollution Act of 1990 amended the Clean Water Act in large part due to the Exxon Valdez incident. Under the Oil Pollution Act, the EPA was directed to promulgate regulations which would create a comprehensive prevention, response, liability and compensation program to deal with oil discharged into United States navigable waters. The Oil Pollution Act imposes ongoing requirements on owners and operators of facilities that handle certain quantities of crude oil, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with a spill. The Oil Pollution Act imposes liability for removal costs and damages resulting from an incident in which oil is discharged into navigable waters and establishes liability for damages for injuries to, or loss of, natural resources.

Air Emissions

The Clean Air Act, and comparable state laws, regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources. In October 2015, the EPA finalized rules that lower the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 parts per billion ("ppb") to 70 ppb, and the EPA published a final rule in July 2018 completing the final designations. States can also impose air emissions limitations that are more stringent than the federal standards imposed by the EPA. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Clean Air Act and associated state laws and regulations. Rules restricting air emissions may require a number of modifications to our operations, including the installation of new equipment. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our operating results. However, we believe that our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies. We believe that our operations are in substantial compliance with federal and state air emission standards.

Climate Change

While the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, the EPA has used existing authority under the Clean Air Act to regulate GHGs. For example, the EPA has adopted rules requiring the reporting of GHG emissions from various oil and natural gas operations on an annual basis. In addition, in June 2016, the EPA published New Source Performance Standards ("NSPS") Subpart OOOOa standards that require new, modified or reconstructed facilities in the oil and natural gas sector to reduce methane gas and volatile organic compound emissions. However, in June 2017, the EPA published a proposed rule to stay portions of the Subpart OOOOa standards for two years. In September 2018, the EPA issued proposed revisions to the NSPS applicable to new and modified oil and gas sources, which would reduce the monitoring obligations for wells and compressor stations. Further in October 2018, the EPA issued a draft report which includes a template designed to assist with compliance. In August 2020, EPA issued two final rules that will make it simpler for the oil and gas industry to comply with NSPS. The first policy amendments remove the transmission and storage segment from the rule, rescind VOC and methane emission standards for that segment and rescind methane emission standards for the production and processing segments. The second simplifies compliance requirements. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to possess and acquire emission allowances which permit corresponding GHG emissions. Furthermore, the U.S. is currently a party to the Paris Agreement adopted in December 2015 to reduce global GHG emissions. However, in June 2017, President Trump announced that the United States plans to withdraw from the Paris Agreement in accordance with the Agreement's four-year exit process and to seek negotiations either to reenter the Paris Agreement on different terms or establish a new framework agreement. In August 2017, the U.S. Department of State officially informed the United Nations of the intent of the United States to withdraw from the Paris Agreement and on November 4, 2020 the United States officially withdrew from the Paris Agreement. However, on January 20, 2021, President Biden signed an executive order to have the United States rejoin the Paris Agreement. On November 4,2020 the withdrawal took effect. However, on January 20, 2021 President Biden signed an Executive Order to reverse the withdrawal and the United States formally re-joined the Paris Agreement on February 19, 2021. Additionally, President Biden has issued an executive order seeking to adopt new regulations and policies to address climate change and suspend, revise or rescind prior agency actions that are identified as conflicting with the Biden Administration's climate policies.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing practices and has finalized a study of the potential environmental impacts of hydraulic fracturing activities, finding that under certain circumstances, the "water cycle" activities associated with hydraulic fracturing may impact drinking water resources. In 2014, the EPA released an Advanced Notice of Proposed Rulemaking seeking public comment on its plans to issue regulations under the Toxic Substances Control Act of 1976 to require companies to disclose information regarding chemicals used in hydraulic fracturing. Further, the Department of the Interior has released final regulations governing hydraulic fracturing on federal oil and natural gas leases which require lessees to file for approval of well stimulation work before commencement of operations and require well operators to disclose the trade names and purposes of additives used in the fracturing fluids. The states in which we operate have also adopted disclosure requirements related to fracturing fluids. Legislation has been introduced, but not adopted, in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. In addition, some states have adopted, and other states are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances. Currently, no states in which we utilize hydraulic fracturing have adopted these regulations. In addition, President Biden has declared that he would support federal government efforts to limit or prohibit hydraulic fracturing. These declarations include threats to take actions banning hydraulic fracturing of crude oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. On January 20, 2021, the Acting Secretary for the Department of the Interior signed an order suspending new fossil fuel leasing and permitting on federal lands for 60 days. In addition, on January 20, 2021, President Biden issued an Executive Order on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" seeking to adopt new regulations and policies to address climate change and suspend, revise, or rescind, prior agency actions that are identified as conflicting with the Biden Administration's climate policies. Among the areas that could be affected by the review are regulations addressing hydraulic fracturing. At this time, it is not possible to accurately estimate how these recent actions and future rules and rulemaking initiatives under the Biden administration will impact our business.

Endangered Species

The federal Endangered Species Act ("ESA") was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service ("FWS") may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions and may materially delay or prohibit land access for development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the FWS was required to make a determination on the listing of more than 250 species as endangered or threatened under the ESA by the end of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities.

Gathering System Regulation

Regulation of gathering facilities may affect certain aspects of our business and the market for our services. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily the Federal Energy Regulatory Commission ("FERC"). The FERC regulates interstate natural gas transportation rates, terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

The transportation and sale for resale of natural gas in interstate commerce are regulated primarily under the Natural Gas Act ("NGA"), and by regulations and orders promulgated under the NGA by the FERC. In certain limited circumstances, intrastate transportation, gathering, and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by the U.S. Congress and by FERC regulations.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests that the FERC has used to establish whether a pipeline is a gathering pipeline not subject to FERC jurisdiction. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services has been the subject of substantial litigation and varying interpretations. In addition, the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of our natural gas gathering facilities are subject to change based on future determinations by the FERC, the courts, or the U.S. Congress. If the FERC were to determine that an individual gathering system is not exempt from FERC regulation and the pipelines associated with such gathering system provide interstate transportation, the rates for, and terms and conditions of, services provided by such gathering system would be subject to regulation by the FERC. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect results of operations and cash flows. If any of our facilities were found to have provided services or otherwise operated in violation of the NGA or the NGPA, this could result in the imposition of civil penalties as well as a requirement to disgorge charges collected for such service in excess of the cost-based rate established by the FERC.

Gathering services, which may occur upstream of transmission service subject to FERC jurisdiction, is regulated by the states. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. Our purchasing and gathering operations are subject to ratable take and common purchaser statutes in the State of Texas. The ratable take statute generally requires gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, the common purchaser statute generally requires gatherers to purchase without undue discrimination as to source of supply or producer. These statutes are designed to prohibit discrimination in favor of one producer over another producer or one source of supply over another source of supply. These statutes have the effect of restricting our right as an owner of gathering facilities to decide with whom we contract to purchase or transport gas.

The Railroad Commission of Texas ("TRRC") requires gatherers to file reports, obtain permits, make books and records available for audit and provide service on a nondiscriminatory basis. Shippers and producers may file complaints with the TRRC to resolve grievances relating to natural gas gathering access and rate discrimination.

While our gathering systems have not been regulated by the FERC under the NGA, the U.S. Congress may enact legislation or the FERC may adopt regulations that may subject certain of our otherwise non-FERC jurisdictional facilities to further regulation. Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas gatherers with which we compete. Failure to comply with those regulations in the future could subject us to civil penalty liability.

The Energy Policy Act of 2005 ("EPAct 2005"), amended the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by the FERC, and furthermore provides the FERC with additional civil penalty authority. The EPAct 2005 provided the FERC with the power to assess daily civil penalties for violations of the NGA and the Natural Gas Policy Act ("NGPA"). The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. In Order No. 670, the FERC promulgated rules implementing the anti-market manipulation provision of the EPAct 2005. The rules make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to: (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act or practice that operates as a fraud or deceit upon any person. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction.

Pipeline Safety Regulation

We are subject to regulation by the United States Department of Transportation ("DOT") through the Pipelines and Hazardous Materials Safety Administration ("PHMSA"), pursuant to the Hazardous Liquid Pipeline Safety Act of 1979, as amended ("HLPSA") and comparable state statutes with respect to design, installation, inspection, testing, construction, operation, replacement and maintenance of pipeline facilities. HLPSA, as amended, governs he design, installation, testing, construction, operation, replacement and management of crude oil pipeline facilities and also covers petroleum and petroleum products, including NGLs and condensate, and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the U.S. Secretary of Transportation. These regulations include potential fines and penalties for violations. We believe that we are in compliance in all material respects with these HLPSA regulations.

Our natural gas pipelines are subject to regulation by PHMSA pursuant to the Natural Gas Pipeline Safety Act of 1968 ("NGPSA") and the Pipeline Safety Improvement Act of 2002 ("PSIA"), as reauthorized and amended by the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 ("PIPES Act"). The NGPSA regulates safety requirements in the design, construction, operation and maintenance of gas pipeline facilities, while the PSIA establishes mandatory inspections for all U.S. oil and natural gas transmission pipelines in high-consequence areas ("HCAs").

PHMSA has developed regulations that require pipeline operators to implement integrity management programs, including more frequent inspections and other measures to ensure pipeline safety in HCAs. The regulations require operators, including us, to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact HCAs;
- improve data collection, integration and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating actions.

The HLPSA has been amended by the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 ("2011 Pipeline Safety Act") and the Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2016 ("2016 Pipeline Safety Act The 2011 Pipeline Safety Act increased the penalties for safety violations, established additional safety requirements for newly constructed pipelines and required studies of safety issues that could result in the adoption of new regulatory requirements by PHMSA for existing pipelines. The 2011 Pipeline Safety Act doubled the maximum administrative fines for safety violations from $100,000 to $200,000 for a single violation and from $1 million to $2 million for a related series of violations, but provided that these maximum penalty caps do not apply to certain civil enforcement actions. Effective April 27, 2017, to account for inflation, those maximum civil penalties were increased to $213,268 per day, with a maximum of $2,132,679 for a series of violations. The 2016 Pipeline Safety Act extended PHMSA's statutory mandate through 2019. The 2016 Pipeline Safety Act also empowers PHMSA to address imminent hazards by imposing emergency restrictions, prohibitions and safety measures on owners and operators of hazardous liquid pipeline facilities without prior notice or an opportunity for a hearing. PHMSA issued interim regulations in October 2016 to implement the agency's expanded authority to address unsafe pipeline conditions or practices that pose an imminent hazard to life, property, or the environment.

PHMSA regularly revises its pipeline safety regulations and has published advanced notices of proposed rulemakings and notices of proposed rulemaking to solicit comments on the need for changes to its natural gas and liquid pipeline safety regulations. In the past few years, PHMSA issued advisory bulletins providing guidance on applicable regulatory requirements, including those that must be followed for the abandonment of a pipeline; aspects of overall pipeline integrity, including the need for corrosion-control systems on buried and insulated pipeline segments, to conduct in-line inspections for all threats, and to ensure in-line inspection tool findings are accurate and verified; the need of owners and operators of natural gas facilities to take appropriate steps to prevent damage to pipeline facilities from accumulated snow or ice; actions pipeline operators should consider taking to ensure the integrity of pipelines in the event of severe flooding or hurricane damage; notice of construction; flow reversal procedures; product changes and conversion; integrity management program evaluation metrics; and incident response plans. Further changes to PHMSA's rules are expected in the future.

For example, in July 2015, PHMSA issued a notice of proposed rulemaking proposing, among other things, to extend operator qualification requirements to operators of certain natural gas gathering lines and to add a specific timeframe for operators' notifications of accidents or incidents. In January 2017, PHMSA issued a final rule adding a specific timeframe for operators' notifications of accidents or incidents but delayed final action on the operator qualification proposals until a later date. The final rule became effective March 24, 2017. In addition, in October 2015, PHMSA issued a notice of proposed rulemaking proposing changes to its hazardous liquid pipeline safety regulations, including to extend: (i) reporting requirements to all onshore or offshore, regulated or unregulated hazardous liquid gathering lines; and (ii) certain integrity management periodic assessment and remediation requirements to regulated onshore gathering lines. On January 13, 2017, PHMSA issued a final rule amending its regulations to impose new reporting requirements for certain unregulated pipelines, including all hazardous liquid gathering lines. The final rule also significantly extends and expands the reach of certain integrity management requirements, regardless of the pipeline's proximity to HCAs. However, this final rule remains subject to review and approval by the new administration, pursuant to a memorandum issued by the White House to heads of federal agencies. It is unclear whether the final rule will be revised and when it will be implemented. In April 2016, PHMSA issued a notice of proposed rulemaking that would expand integrity management requirements and impose new pressure requirements on currently regulated gas transmission pipelines and would also significantly expand the regulation of gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. On October 1, 2019, PHMSA issued its final rule which became effective July 1, 2020. While we cannot predict the outcome of legislative or regulatory initiatives, such regulatory changes and any legislative changes could have a material effect on our operations, particularly by extending more stringent and comprehensive safety regulations (such as integrity management requirements) to pipelines and gathering lines not previously subject to such requirements. While we expect any legislative or regulatory changes to allow us time to become compliant with new requirements, costs associated with compliance may have a material effect on our operations.

Furthermore, DOT regulations have incorporated by reference the American Petroleum Institute Standard 653 ("API 653") as the industry standard for the inspection, repair, alteration and reconstruction of storage tanks. API 653 requires regularly scheduled inspection and repair of such tanks. These periodic tank maintenance requirements may result in significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our storage tanks.

States are largely preempted by federal law from regulating pipeline safety for interstate lines but most are certified by the DOT to assume responsibility for enforcing intrastate pipeline regulations and inspection of intrastate pipelines. For example, in Texas the Pipeline Safety Department of the TRRC inspects and enforces the pipeline safety regulations for intrastate pipelines, including gathering lines. States may adopt stricter standards for intrastate pipelines than those imposed by the federal government for interstate lines; however, states vary considerably in their authority and capacity to address pipeline safety. State standards may include more stringent requirements for facility design and management in addition to requirements for pipelines. We do not anticipate any significant difficulty in complying with applicable state laws and regulations. Our pipelines have ongoing inspection and compliance programs designed to keep the facilities in compliance with pipeline safety and pollution control requirements.

We have incorporated all existing requirements into our programs by the required regulatory deadlines and are continually incorporating the new requirements into procedures and budgets. We expect to incur increasing regulatory compliance costs, based on the intensification of the regulatory environment and upcoming changes to regulations as outlined above. In addition to regulatory changes, costs may be incurred when there is an accidental release of a commodity gathered on our system, or a regulatory inspection identifies a deficiency in our required programs.

Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act (“OSHA”), and comparable state laws. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communications standard, OSHA Process Safety Management, the EPA community right-to-know regulations under Title III of CERCLA and similar state laws require that we organize and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements should not have a material adverse impact on our financial condition and results of operations. As of December 31, 2019, we had no accrued environmental obligations. We are not aware of any environmental issues or claims that will require material capital expenditures or that will otherwise have a material impact on our financial position or results of operations. However, we cannot predict how future environmental laws and regulations may impact our operations, and therefore, cannot provide assurance that the passage of more stringent laws or regulations in the future will not have a negative impact on our financial condition, results of operations or cash flows.

Human Capital

Headcount

We do not have any employees. Pursuant to the terms of the Operational Services Agreement, our subsidiary SNMP Services provides us and certain of our subsidiaries, including SEP Holdings IV, LLC, Catarina Midstream, LLC and SECO Pipeline, LLC, with payroll, human resources, employee benefits and other consulting services we mutually agree upon with SNMP Services. Following the effective date of the Operational Services Agreement, SOG no longer provides any employees or support staff for our business. As of March 16, 2021, thirteen (13) employees were employed by SNMP Services with their primary function being to provide services for us, all of which were full-time employees. None of SNMP Services’ employees are subject to a collective bargaining agreement. When we refer to “our employees” in this Form 10-K we are referring the SNMP Services’ employees. Our success is due in large part to the skills, experience and dedication of such employees.

Employee Safety

We believe our responsibility to our employees, neighbors, shareholders and the environment is only fulfilled through our commitment to safety and reliability. Through training, continuous monitoring and promoting a culture of excellence in operations, we continuously strive to keep our people, the communities in which we operate in and the environment safe. By monitoring the integrity of our assets and promoting the safety of our employees, we are investing in the long-term sustainability of our business.

We are subject to the requirements of OSHA and comparable state statutes that regulate the protection of the health and safety of workers. In addition, the OSHA Hazard Communication Standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in compliance with OSHA requirements, including general industry standards, record keeping requirements and monitoring of occupational exposure to regulated substances.

In response to COVID-19, we have taken steps to manage the potential impacts of the COVID-19 outbreak on our employees. We continue to practice remote work procedures when possible to protect the safety of our employees and their families, and have taken extra precautions for our employees who work in the field or cannot otherwise work remotely, such as social distancing, face covering protocols and sanitation procedures.

Development and Retention

In managing our human capital resources, we use a strategic approach to building a diverse, inclusive, and respectful workplace. SNMP Services provides expertise and tools to attract, develop, and retain diverse talent and support our employees' career and development goals. We value our employees' opinions and encourage them to engage with management and ask questions on topics such as our goals, challenges, and employee concerns.

We believe that a combination of competitive compensation and career growth and development opportunities help increase employee morale and reduce voluntary turnover. Our comprehensive benefit packages are competitive in the marketplace and we believe in recognizing and rewarding talent through our various compensation programs.

Health and Welfare

We provide a variety of benefits to help promote the health and welfare of our employees and their families. These benefits include medical, dental, vision plans and virtual health visits. Eligible employees also have access, at no charge, to an employee assistance program.

Offices

Our principal executive offices are located at 1360 Post Oak Blvd., Suite 2400, Houston, Texas 77056. Our telephone number is (713) 783-8000.

Available Information

Our internet address is http://www.evolvetransition.com. We make our website content available for informational purposes only. It should not be relied upon for investment purposes, nor is it incorporated by reference in this Form 10-K. We make available free of charge on or through our website our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The SEC maintains an internet website that contains these reports at http://www.sec.gov.

Item 1A. Risk Factors

Summary of Risk Factors

The following summary outlines our Risk Factors, which we have grouped into risk categories. These summarized Risk Factors should be read in conjunction with the detailed Risk Factors that follow:

Risks Related to the COVID-19 pandemic

- The COVID-19 pandemic has had and could continue to have a material adverse impact on our business, financial condition, cash flows and results of operations.

Risks Related to the Rejection Lawsuits and the Settlement Agreement

- The failure of the Bankruptcy Court to approve the rejection of the certain commercial agreements underlying the Rejection Lawsuits, or the termination of the Settlement Agreement by any party, could adversely affect our business, financial condition, cash flows and results of operations.

Risks Related to Our Energy Transition Infrastructure Business

- We can provide no assurance that we will be successful in implementing our new energy transition infrastructure business due to competition and other factors, which could limit our ability to grow and extend our dependence on Mesquite and our midstream business.

Risks Related to Our Midstream Business

- Mesquite accounts for the majority of our total revenue in general and substantially all of our revenue relating to the operation of our midstream business, as a result, any development that materially and adversely affects Mesquite's business, financial condition, cash flows or results of operations could have a material and adverse impact on us.

- The minimum volume commitment provisions of the Gathering Agreement expired in 2020, which could adversely affect our business, financial condition, cash flows and results of operations.

- All of our midstream assets are located in the Eagle Ford Shale in Texas, making us vulnerable to risks associated with operating in one major geographic area.

- Distributions we receive from the Carnero JV may fluctuate from quarter to quarter, which could adversely affect our cash flows and ability to pay our payables timely.

Risks Related to Our Production Business

- Market conditions for natural gas, NGLs and oil are highly volatile. A sustained decline in prices for these commodities could adversely affect our revenue, cash flows, profitability and growth.

- We depend on certain key customers for sales of our oil and natural gas. To the extent these and other customers reduce the volumes of oil or natural gas they purchase from us and are not replaced by new customers, our revenues and cash available for distribution could decline.

Risks Related to Our Midstream and Production Businesses

- As a non-operator, our development of successful operations relies extensively on third-parties, including Mesquite and Targa, which could adversely affect our business, financial condition and results of operations

Risks Related to Financing and Credit Environment

- Our independent registered public accounting firm has expressed doubt about our ability to continue as a going concern.

- Our Credit Agreement has substantial prepayment requirements, other restrictions and financial covenants and requires periodic borrowing base redeterminations.
- We may not be able to extend, replace or refinance our Credit Agreement on terms reasonably acceptable to us, or at all, which could materially and adversely affect our business, liquidity, cash flows and prospects.

Risks Related to Our Cash Distributions

- Our partnership agreement prohibits us from making certain distributions until all of the Class C Preferred Units are redeemed and, as a result, our ability to make, maintain and grow cash distributions is dependent on our ability to redeem the Class C Preferred Units.
- Our Credit Agreement restricts us from paying any distributions on our outstanding common units.
- Any termination of the Shared Services Agreement requiring the payment of a termination fee may result in substantial dilution and could adversely affect our financial condition, results of operations, operating cash flows and any ability to pay cash distributions.

Risks Related to Regulatory Compliance

- Increased regulation of hydraulic fracturing could result in reductions or delays in the production of natural gas, NGLs and oil by Mesquite, which could reduce the throughput on our facilities and adversely impact our revenues.

Risks Inherent in an Investment in Our Common Units

- We are currently not in compliance with the NYSE American listing standards. If our common units are delisted, it could result in even further reductions in the trading price and liquidity of our common units, which could materially adversely affect our ability to raise capital or pursue strategic transactions on acceptable terms, or at all.
- Certain events may result in our general partner exercising its limited call right, which may require common unitholders to sell their common units at an undesirable time or price.
- Stonepeak Catarina and its affiliates, including our general partner, will have conflicts of interest with us. They will not owe any fiduciary duties to us or our common unitholders, but instead will owe us and our common unitholders limited contractual duties, and they may favor their own interests to the detriment of us and our other common unitholders
- Our partnership agreement replaces our general partner's fiduciary duties to our common unitholders with contractual standards governing its duties.
- We are able to issue additional units without common unitholder approval, which would dilute unitholder interests.

Tax Risks

- The tax treatment of publicly traded partnerships or an investment in our common units could be subject to potential legislative, judicial or administrative changes and differing interpretations, possibly on a retroactive basis.
- Our common unitholders' share of our income will be taxable to them even if they do not receive any cash distributions from us.

Risk Factors

Our business involves a high degree of risk. Limited partner interests are inherently different from the capital stock of a corporation, although many of the business risks to which we are subject are similar to those that would be faced by a corporation engaged in a similar business. You should consider and read carefully all of the risks and uncertainties described below, together with all of the other information contained in this Form 10-K, including the financial statements and the related notes appearing at the end of this Form 10-K. If any of the following risks, or any risk described elsewhere in this Form 10-K, were to occur, our business, financial condition or results of operations could be adversely affected. If any of the following risks, or any risk described elsewhere in this Form 10-K, were to occur, our business, financial condition or results of operations could be adversely affected. The risks below are not the only ones facing the Partnership. Additional risks not currently known to us or that we currently deem immaterial may also adversely affect us. This Form 10-K also contains forward-looking statements, estimates and projections that involve risks and uncertainties. Our actual results could differ materially from those anticipated in the forward-looking statements as a result of specific factors, including the risks described below. Please read "Cautionary Note Regarding Forward-Looking Statements."

Risks Related to the COVID-19 Pandemic

The COVID-19 pandemic has had and could continue to have a material adverse impact on our business, financial condition, cash flows and results of operations.

COVID-19 has had and could continue to have a material adverse impact on our business, including our financial condition, cash flows and results of operations. COVID-19 was first reported in December 2019 and has since spread to over 200 countries and territories, including every state in the United States. In March 2020, the World Health Organization declared COVID-19 a pandemic and recommended containment and mitigation measures worldwide and the United States declared a national emergency with respect to COVID-19. As a result, extraordinary and wide-ranging actions were taken by international, federal, state and local public health and governmental authorities to reduce the spread of COVID-19, including quarantines, government restrictions on movement, business closures and suspensions, canceled events and activities, self-isolation, and other voluntary or mandated changes in behavior. Such actions have also resulted in significant business and operational disruptions, including supply chain disruptions, travel restrictions, stay-at-home orders and limitations on the availability of workforces. COVID-19 and the ongoing response to mitigate its impact have contributed to a massive economic shutdown and decreased demand for crude oil and natural gas.

As the pandemic and responses to it continue, we may experience further disruptions to commodities markets, supply chains and the health, availability and efficiency of our workforce, which could adversely affect our ability to conduct our business and operations and limit our ability to execute on our business plan. Both the outbreak of the disease and measures taken to slow its spread have created significant uncertainty and economic volatility and disruption, which have impacted and may continue to impact our business operations and have materially adversely affected and may continue to materially adversely affect our results of operations, cash flows and financial performance, including, but not limited to, the following:

- a delay in timing for the collections of our receivables for the services we perform, including as a result of deteriorating financial condition resulting from the COVID-19 pandemic and resulting economic impacts;

- illness, travel restrictions or other workforce disruptions impacting the availability or productivity of our employees;

- increased volatility and pricing in the capital markets and credit markets, which may reduce the availability of, and our ability to access, sources of liquidity on acceptable pricing or borrowing terms, if at all; and

- disruptions in the ability of our suppliers, subcontractors, joint venture partners and others to satisfy their obligations with respect to us, which has impacted, and could continue to impact, our liquidity position, which could result in our inability to pay our payables timely, including required payments under the Credit Agreement.

There are still too many variables and uncertainties regarding COVID-19 — including the pace and efficacy of vaccination efforts, the duration and severity of possible resurgences and the duration and extent of travel restrictions and business closures imposed in affected countries — to reasonably predict the full potential impact of COVID-19 on our business and operations. Even after the COVID-19 pandemic has subsided, we may experience materially adverse impacts to our business due to the global economic recession that is likely to result from the measures taken to combat the virus. Further, adverse impacts from the COVID-19 pandemic may have the effect of heightening many of the other risks we face.

Risks Related to the Rejection Lawsuits and the Settlement Agreement

The failure of the Bankruptcy Court to approve the rejection of the certain commercial agreements underlying the Rejection Lawsuits, or termination of the Settlement Agreement by any party, could adversely affect our business, financial condition, cash flows and results of operations.

On June 30, 2020, the United States Bankruptcy Court for the Southern District of Texas, Houston Division (the "Bankruptcy Court") entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, including but not limited to, (i) Amendment No. 2 to the Gathering Agreement, (ii) the Seco Catarina Agreement, and (iii) the Seco Comanche Agreement. Each of the agreements that were entered into on June 30, 2020 pursuant to the Settlement Agreement will become effective upon satisfaction of certain closing conditions described in the Settlement Agreement.

On June 23, 2020, certain affiliates of each Occidental Petroleum Corp., The Blackstone Group and GSO Capital Partners each filed a complaint (collectively, the "Rejection Lawsuits") against Mesquite and certain of its subsidiaries. The commercial agreements contemplated by the Settlement Agreement that the Partnership and its subsidiaries entered into on June 30, 2020 will not become effective until, among other things, the Rejection Lawsuits have been resolved and the Bankruptcy Court has approved the rejection of the certain commercial agreements underlying the Rejection Lawsuits in favor of the SN Debtors. The Rejection Lawsuits were not resolved as of December 31, 2020, and as a result, each of the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms.

The failure of the Bankruptcy Court to approve the rejection of the certain commercial agreements underlying the Rejection Lawsuits, or the termination of the Settlement Agreement by any party could adversely affect our business, financial condition, cash flows and results of operations.

Risks Related to Our Energy Transition Infrastructure Business

We can provide no assurance that we will be successful in implementing our new energy transition infrastructure business due to competition and other factors, which could limit our ability to grow and extend our dependence on Mesquite and our midstream business.

Part of our new business strategy is to grow our business through the acquisition and development of infrastructure critical to the transition of energy supply to lower carbon sources. This will involve identifying opportunities to offer services to third parties with our existing assets or constructing or acquiring new assets. We are currently pursuing energy transition infrastructure opportunities but we have not yet closed an acquisition or developed infrastructure in connection with this business strategy. We can provide no assurance that we will be successful in implementing our new energy transition infrastructure business, which could limit our ability to grow and extend our dependence on Mesquite and our midstream business. Moreover, we may fail to realize the anticipated benefit of any acquisition we do close, or we may be unable to integrate businesses we acquire effectively. Finally, to the extent that Stonepeak, SP Holdings or our general partner are successful in pursuing energy transition opportunities, there is no guarantee that such opportunities will be offered to us. Please read "—Risks Inherent in an Investment in Our Common Units—Our general partner and its affiliates, including SP Holdings and Stonepeak Catarina, may not allocate corporate opportunities to us."

Risks Related to Our Midstream Business

Mesquite accounts for the majority of our total revenue in general and substantially all of our revenue relating to the operation of our midstream business, as a result, any development that materially and adversely affects Mesquite's business, financial condition, cash flows or results of operations could have a material and adverse impact on us.

Mesquite is our most significant customer and accounted for approximately 80% of our total revenue and substantially all of our midstream business revenue for the year ended December 31, 2020. We are dependent on Mesquite as our only current customer for utilization of Western Catarina Midstream. In addition, Mesquite is the primary customer for utilization of the Carnero Gathering Line and the Raptor Gas Processing Facility. We expect that a majority of revenues relating to these assets will be derived from Mesquite for the foreseeable future. As a result, any event, whether in our area of operations or otherwise, that adversely affects Mesquite's production, drilling and completion schedule, financial condition, leverage, market reputation, liquidity, results of operations or cash flows could have a material and adverse impact on us. Accordingly, we are indirectly subject to the business risks of Mesquite, including, among others:

- a reduction in or slowing of Mesquite's development program, especially on Mesquite's Catarina Asset, which would directly and adversely impact demand for our gathering and processing services;
- a decline in the price of natural gas, NGLs or oil, which have been extremely volatile prior to, and during the pendency of, the COVID-19 pandemic;
- Mesquite's ability to finance its operations and development activities;
- the availability of capital on an economic basis to fund Mesquite's exploration and development activities;
- Mesquite's ability to replace reserves;
- Mesquite's drilling and operating risks, including potential environmental liabilities;
- transportation capacity restraints and interruptions;
- adverse effects of governmental and environmental regulation; and
- losses from pending or future litigation, including the Rejection Lawsuits.

Because of the natural decline in production from existing wells, our success depends, in part, on Mesquite's ability to replace declining production. Any decrease in volumes of natural gas, NGLs and oil that Mesquite produces or any decrease in the number of wells that Mesquite completes could reduce throughput volumes that could adversely affect our business and operating results.

The volumes that support our facilities depend on the level of production from wells connected to our facilities, which may be less than expected and will naturally decline over time. During the year ended December 31, 2020, Mesquite failed to drill the required number of wells on Mesquite's Catarina Asset, and as a result, Mesquite forfeited acreage not held by production during the year ended December 31, 2020. This forfeiture will impact Mesquite's ability to develop additional acreage and replace declining production, which will directly impact revenues for our gathering and processing services.

In addition, volumes from completed wells will naturally decline and our cash flows associated with these wells will also decline over time. In order to maintain or increase throughput levels on our facilities, we must obtain new sources of natural gas, NGLs and oil from Mesquite or other third parties. The primary factors affecting our ability to obtain additional sources of natural gas, NGLs and oil include (i) the success of Mesquite's drilling activity in our areas of operation, (ii) Mesquite's acquisition of additional acreage and (iii) our ability to obtain additional dedications of acreage from Mesquite or new dedications of acreage from other third parties.

We have no control over Mesquite's or other producers' levels of development and completion activity in our areas of operation, the amount of reserves associated with wells connected to our facilities or the rate at which production from a well declines. We have no control over Mesquite or other producers or their development plan decisions, which are affected by, among other things:

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

Fluctuations in energy prices can also greatly affect the development of reserves. Declines in commodity prices could have a negative impact on Mesquite's development and production activity, and if sustained, could lead Mesquite to materially reduce its drilling and completion activities. Sustained reductions in development or production activity in our areas of operation could lead to reduced utilization of our services.

Due to these and other factors, even if reserves are known to exist in areas served by our facilities, Mesquite and other producers may choose not to develop, or be prohibited from developing, those reserves. If reductions in development activity result in our inability to maintain the current levels of throughput on our facilities, those reductions could adversely affect our business and operating results.

The minimum volume commitment provisions of the Gathering Agreement expired in 2020, which could adversely affect our business, financial condition, cash flows and results of operations.

The term of the minimum volume commitment was the first five years of the 15-year term of the Gathering Agreement. The minimum volume commitment term expired in 2020. As a result, Mesquite has no contractual commitment with respect to throughput volumes and if Mesquite's actual throughput volumes are less than anticipated, we will not be entitled to receive any shortfall payments. If Mesquite's throughput volumes decrease materially, or if Mesquite ceased shipping throughput volumes on Western Catarina Midstream, it would have a material adverse effect on our business, financial condition, cash flows and results of operations.

Interruptions in operations at our facilities or facilities that Targa operates on behalf of the Carnero JV may adversely affect our business, financial condition, cash flows and results of operations.

Any significant interruption at any of our facilities or the facilities that Targa operates on behalf of the Carnero JV, or in our ability or Targa's ability on behalf of the Carnero JV, as applicable, to gather, treat or process natural gas, NGLs and oil, would adversely affect our business, financial condition, cash flows and results of operations. Operations at impacted facilities could be partially or completely shut down, temporarily or permanently, as a result of circumstances not within our control, such as:

- unscheduled turnarounds or catastrophic events at 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 or decline in the supply of resources necessary to operate a facility;
- damage to facilities resulting from natural gas, NGLs and oil that do not comply with applicable specifications; and
- inadequate transportation or market access to support production volumes, including lack of availability of pipeline capacity.

We may not be able to attract additional third-party volumes, which could limit our ability to grow and would increase our dependence on Mesquite.

Part of our long-term growth strategy includes identifying additional opportunities to offer gathering, processing and transportation services to other third parties. Our ability to increase throughput on our facilities and any related revenue from third parties is subject to numerous factors beyond our control, including competition from third parties and the extent to which we have available capacity when requested by third parties. To the extent that we lack available capacity on our facilities for third-party volumes, we may not be able to compete effectively with third-party gathering or processing systems for additional volumes. In addition, some of our competitors for third-party volumes have greater financial resources and access to larger supplies of oil and natural gas than those available to us, which could allow those competitors to price their services more aggressively than us. Moreover, the underlying lease for the properties on which Western Catarina Midstream is located restricts Western Catarina Midstream to the handling of hydrocarbons produced on the properties covered by the lease.

We may not be able to attract material third-party service opportunities. Our efforts to attract new unaffiliated customers may be adversely affected by (i) certain rights Mesquite has under applicable agreements and, with respect to Western Catarina Midstream, the fact that a substantial portion of the capacity of the facility will be necessary to service Mesquite's production and development and completion schedule, (ii) the current nature of our facilities, (iii) our desire to provide services pursuant to fee-based contracts and (iv) the existence of current and future dedications to other gatherers by potential third-party customers. As a result, we may not have the capacity or ability to provide services to third parties, or potential third-party customers may prefer to obtain services pursuant to other forms of contractual arrangements under which we would be required to assume direct commodity exposure.

All of our midstream assets are located in the Eagle Ford Shale in Texas, making us vulnerable to risks associated with operating in one major geographic area.

All of our midstream assets are located in the Eagle Ford Shale in Texas. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, market limitations or interruption of the processing or transportation of natural gas, NGLs or oil.

We do not intend to obtain independent evaluations of reserves of natural gas, NGLs and oil reserves connected to Western Catarina Midstream on a regular or ongoing basis; therefore, in the future, volumes of natural gas, NGLs and oil on the gathering system could be less than we anticipate.

We have not obtained and do not intend to obtain independent evaluations of the reserves of natural gas, NGLs and oil, including those of Mesquite, connected to Western Catarina Midstream on a regular or ongoing basis. Moreover, even if we did obtain independent evaluations of the reserves of natural gas, NGLs and oil connected to Western Catarina Midstream, such evaluations may prove to be incorrect. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future 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 some or all of Western Catarina Midstream or the anticipated life of such reserves. If the total reserves or estimated life of the reserves connected to Western Catarina Midstream are less than we anticipate and we are unable to secure additional sources of natural gas, NGLs and oil, it could adversely affect our business, financial condition, cash flows and results of operations.

A shortage of equipment and skilled labor in the Eagle Ford Shale could reduce equipment availability and labor productivity and increase labor and equipment costs, which could have a material adverse effect on our business and results of operations.

Gathering and processing services require special equipment and laborers skilled in multiple disciplines, such as equipment operators, mechanics and engineers, among others. Decreased levels of production and shrinking margins from lower commodity prices may result in shortages of equipment and skilled labor in the Eagle Ford Shale, as companies seek to deploy their resources in more profitable basins. If we experience shortages of necessary equipment or skilled labor in the future, our labor and equipment costs and overall productivity could be materially and adversely affected. Material increases in equipment, labor prices or health and benefit costs for employees, could have a material adverse effect on our business and results of operations.

Distributions we receive from the Carnero JV may fluctuate from quarter to quarter, which could adversely affect our cash flows and ability to pay our payables timely.

We received approximately $15.3 million in cash from the Carnero JV in the form of distributions during the year ended December 31, 2020. Targa, as the operator of the Carnero JV, has certain rights which permit it to affect the amount and timing of distributions to us. For example, Targa has certain discretion with regard to cash reserves and working capital adjustments that may cause the amount of our distributions to fluctuate from quarter-to-quarter. Fluctuations in the amount and timing of distributions from the Carnero JV could adversely affect our cash flows and ability to pay our payables timely, including required payments under the Credit Agreement.

Our participation in joint ventures exposes us to liability or harm to our reputation resulting from failures by our joint venture partners.

In May 2018, we executed a series of agreements with Targa and other parties pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering and Carnero Processing to form an expanded 50 / 50 joint venture in South Texas, Carnero JV, (2) Targa contributed 100% of the equity interest in Silver Oak II to Carnero JV, which expanded the processing capacity of the joint venture from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the Carnero Gathering Line to Carnero JV resulting in the joint venture owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, and (4) Carnero JV received a new dedication from Mesquite and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Mesquite's Comanche Asset pursuant to a new long-term firm gas gathering and processing agreement. We and Targa are jointly and severally liable for all liabilities and obligations of Carnero JV. If Targa fails to perform or is financially unable to bear its portion of required capital contributions or other obligations, including liabilities stemming from claims or lawsuits, we could be required to make additional investments, provide additional services or pay more than our proportionate share of a liability to make up for Targa's shortfall. Further, if we are unable to adequately address Targa's performance issues, Mesquite, the main customer on the facilities, may terminate its agreements, which could result in legal liability to us, harm our reputation and reduce cash flows generated from the Carnero Gathering Line and the Raptor Gas Processing Facility.

Increased competition from other companies that provide gathering services could have a negative impact on the demand for our services, which could adversely affect our business, financial condition, cash flows and results of operations.

Our ability to flow a sufficient volume of throughput prior to and after the expiration of the Gathering Agreement to maintain current revenues and cash flows could be adversely affected by the activities of our competitors. Our facilities compete primarily with other gathering and processing systems. Some competitors have greater financial resources than us and may now, or in the future, have access to greater supplies of natural gas, NGLs and oil than we do. Some of these competitors may expand or construct facilities that would create additional competition for the services that we provide to Mesquite or other future customers. In addition, Mesquite or other future customers may develop their own facilities instead of using our midstream assets.

All of these competitive pressures could make it more difficult for us to retain Mesquite as a customer and/or attract new customers as we seek to expand our business, which could adversely affect our business, financial condition, cash flows and results of operations.

If third-party pipelines or other midstream facilities interconnected to our facilities become partially or fully unavailable, it could adversely affect our business, financial condition, cash flows and results of operations.

Our facilities connect to other pipelines or facilities owned and operated by unaffiliated third parties. The continuing operation of third-party pipelines, compressor stations and other midstream facilities is not within our control. These pipelines, plants and other midstream facilities may become unavailable because of testing, turnarounds, line repair, maintenance, reduced operating pressure, lack of operating capacity, regulatory requirements and curtailments of receipt or deliveries due to insufficient capacity or because of damage from severe weather conditions or other operational issues. In addition, if the costs to us to access and transport on these third-party pipelines significantly increase, our profitability could be reduced. If any such increase in costs occurs or if any of these pipelines or other midstream facilities become unable to receive or transport natural gas, NGLs or oil, it could adversely affect our business, financial condition, cash flows and results of operations.

We do not own the land on which Western Catarina Midstream or the Seco Pipeline is located, which could have a material adverse effect on our business, results of operations and financial condition.

We do not own the land on which Western Catarina Midstream or the Seco Pipeline is located, and we are, therefore, subject to the possibility of more onerous terms 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. We currently have certain rights to construct and operate our pipelines on land owned by third parties for a specific period of time and may need to obtain other rights in the future from third parties and governmental agencies to continue these operations or expand Western Catarina Midstream or the Seco Pipeline. Our loss of these rights or inability to obtain additional rights, through our inability to renew or obtain right-of-way contracts or otherwise, could have a material adverse effect on our business, results of operations, financial condition.

Our right-of-first-offer with Mesquite for midstream assets is subject to risks and uncertainty, and thus may not enhance our ability to grow our business.

Pursuant to a right-of-first-offer, Mesquite has agreed to offer us the right to purchase midstream assets that it desires to transfer to any unaffiliated person through 2030. Mesquite is under no obligation to sell any assets to us or to accept any offer for its assets that we may choose to make. Furthermore, for a variety of reasons, we may decide not to exercise this right when it becomes available.

The acquisition of additional assets in connection with the exercise of our right-of-first-offer will depend upon, among other things, our ability to agree on the price and other terms of the sale, our ability to obtain financing on acceptable terms for the acquisition of such assets and our ability to acquire such assets on the same or better terms than third parties. We can offer no assurance that we will be able to successfully acquire any assets pursuant to this right-of-first-offer.

Our operations could be disrupted if our information systems are hacked or fail, causing increased expenses and loss of revenue.

We face various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data systems unusable, threats to the security of our facilities and infrastructure, Mesquite’s facilities and infrastructure or other third-party facilities and infrastructure, such as pipelines. The potential for such security threats has subjected our operations to increased risks that could have a material adverse effect on our business.

Our business is increasingly dependent on technology infrastructure, certain critical financial, accounting and other data processing systems and other communications and information systems. These systems include data network and telecommunications, internet access, our website, and various computer hardware equipment and software applications, including those that are critical to the safe operations of our assets. We process transactions on a daily basis and rely upon the proper functioning of computer systems. Additionally, we rely on information systems across our operations, including the management of processes and transactions. These systems are subject to damage or interruption from a number of potential sources including natural disasters, software viruses or other malware, power failures, cybersecurity threats to gain unauthorized access to sensitive information, cyber-attacks, which may render data systems unusable, and physical threats to the security of our facilities and infrastructure or third-party facilities and infrastructure. If a key system were hacked or otherwise interfered with by an unauthorized access, or were to fail or experience unscheduled downtime for any reason, even if only for a short period, our financial results could be affected adversely.

The implementation of social distancing measures and other limitations on our workforce in response to the COVID-19 pandemic have necessitated portions of our workforce switching to remote work arrangements. The increase in companies and individuals working remotely has increased the frequency and scope of cyber-attacks and the risk of potential cybersecurity incidents, both deliberate attacks and unintentional events. While, to date, we have not had a significant cybersecurity breach or attack that had a material impact on our business or results of operations, if we were to be subject to a material successful cyber intrusion, it could result in remediation or service restoration costs, increased cyber protection costs, lost revenues, litigation or regulatory actions by governmental authorities, increased insurance premiums, reputational damage and damage to our competitiveness, financial condition, results of operations and cash flows.

Cyber-attacks against us or others in our industry could result in additional regulations, and U.S. government warnings have indicated that infrastructure assets, including pipelines, may be specifically targeted by certain groups. These attacks include, without limitation, malicious software, ransomware, attempts to gain unauthorized access to data, and other electronic security breaches. These attacks may be perpetrated by state-sponsored groups, “hacktivists”, criminal organizations or private individuals (including employee malfeasance). Current efforts by the federal government and any potential future regulations could lead to increased regulatory compliance costs, insurance coverage cost or capital expenditures. We cannot predict the potential impact to our business or the energy industry resulting from additional regulations.

Further, our business interruption insurance may not compensate us adequately for losses that may occur. We do not carry insurance specifically for cybersecurity events; however, certain of our insurance policies may allow for coverage of associated damages resulting from such events. If we were to incur a significant liability for which we were not fully insured, it could have a material adverse effect on our financial position, results or operations and cash flows. In addition, the proceeds of any such insurance may not be paid in a timely manner and may be insufficient if such an event were to occur.

Risks Related to Our Production Business

Market conditions for natural gas, NGLs and oil are highly volatile. A sustained decline in prices for these commodities could adversely affect our revenue, cash flows, profitability and growth.

Prices for natural gas, NGLs and oil fluctuate widely in response to a variety of factors that are beyond our control, such as:

- domestic and foreign supply of and demand for natural gas, NGLs and oil;
- weather conditions and the occurrence of natural disasters;
- overall domestic and global economic conditions;
- political and economic conditions in countries producing natural gas, NGLs and oil, including terrorist attacks and threats, escalation of military activity in response to such attacks or acts of war;
- actions of the Organization of Petroleum Exporting Countries (“OPEC”) and other state-controlled oil companies relating to oil price and production controls;
- the effect of increasing liquefied natural gas and exports from the United States;
- the impact of the U.S. dollar exchange rates on prices for natural gas, NGLs and oil;

- technological advances affecting energy supply and energy consumption;
- domestic and foreign governmental regulations, including regulations prohibiting or restricting our ability to apply hydraulic fracturing to our wells, and taxation;
- the impact of energy conservation efforts and alternative fuel requirements;
- the proximity, capacity, cost and availability of production and transportation facilities for natural gas, NGLs and oil;
- events that impact global market demand, including impacts from global health epidemics and concerns, such as the coronavirus;
- the availability of refining capacity; and
- the price and availability of, and consumer demand for, alternative fuels.

Given that natural gas, NGLs and oil are global commodities, prices can also be significantly influenced by developments in other countries and markets, particularly in key consumption markets like China and India.

Governmental actions may also affect prices for natural gas, NGLs and oil. In the past, prices for natural gas, NGLs and oil have been extremely volatile, especially during the pendency of the COVID-19 pandemic, and we expect this volatility to continue. Downward volatility can negatively affect the amount of our net estimated proved reserves and the standardized measure of discounted future net cash flows of our net estimated proved reserves.

In addition, our revenue, profitability and cash flows depend upon the prices of and demand for natural gas, NGLs and oil, and continued price volatility and low commodity prices, or a sustained drop in prices could negatively affect our financial results and impede our growth. In particular, sustained declines in commodity prices will:

- limit our ability to enter into commodity derivative contracts at attractive prices;
- reduce the value and quantities of our reserves, because declines in prices for natural gas, NGLs and oil would reduce the amount of natural gas, NGLs and oil that we can economically produce;
- reduce the amount of cash flows available for capital expenditures;
- limit our ability to borrow money; and
- make it uneconomical for our operating partners to commence or continue production levels of natural gas, NGLs and oil.

Our estimated reserves are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our estimated reserves.

It is not possible to measure underground accumulations of oil and natural gas in an exact way. Oil and natural gas reserve engineering requires subjective estimates of underground accumulations of oil and natural gas and assumptions concerning future oil and natural gas prices, production levels and operating and development costs. Our independent reserve engineers do not independently verify the accuracy and completeness of information and data furnished by us. In estimating our level of oil and natural gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

- future oil and natural gas prices;
- production levels;

- capital expenditures;
- operating and development costs;
- the effects of regulation;
- the accuracy and reliability of the underlying engineering and geologic data; and
- the availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, the classifications of reserves based on risk or recovery and our estimates of the future net cash flows from our reserves could change significantly.

Our standardized measure is calculated using unhedged oil and natural gas prices and is determined in accordance with the rules and regulations of the SEC (except for the impact of income taxes as we are not a taxable entity). Over time, we may make material changes to reserve estimates to take into account changes in our assumptions and the results of actual drilling and production.

The reserve estimates that we make for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracies in our estimates of proved reserves, future production rates and the timing of development expenditures.

The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the current market value of our estimated oil and natural gas reserves.

We base the estimated discounted future net cash flows from our estimated proved reserves on prices and costs in effect on the day of the estimate. However, actual future net cash flows from our oil and natural gas properties also will be affected by factors such as:

- the actual prices that are received for oil and natural gas;
- actual operating costs in producing oil and natural gas;
- the amount and timing of actual production;
- the amount and timing of capital expenditures;
- supply of and demand for oil and natural gas; and
- changes in governmental regulations or taxation.

The timing of both production and the incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus, their actual present value. In addition, the 10% discount factor used when calculating our discounted future net cash flows in compliance with the Financial Accounting Standard Board's Accounting Standards may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations, financial condition and cash flows.

Future price declines or downward reserve revisions may result in write-downs of our asset carrying values, which could adversely affect our results of operations and limit our ability to borrow funds.

Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase or production data factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our properties for impairments. We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. We are required to perform impairment tests on our assets periodically and whenever events or circumstances warrant a review of our assets. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our assets, the carrying value may not be recoverable and therefore would require a write-down. We have incurred impairment charges in the past and may do so again in the future. Any impairment could be substantial and have a material adverse effect on our results of operations in the period incurred and our ability to borrow funds under our Credit Agreement.

We depend on certain key customers for sales of our oil and natural gas. To the extent these and other customers reduce the volumes of oil or natural gas they purchase from us and are not replaced by new customers, our revenues and cash flows could decline.

Our oil and natural gas production in Texas and Louisiana is marketed by the operators of our properties. To the extent these or other customers reduce the volumes of oil and natural gas that they purchase from us and are not replaced by new customers, or the market prices for oil and natural gas decline in our market areas, our revenues and cash flows could decline.

Seasonal weather conditions may adversely affect our ability to conduct production activities, which could adversely impact our cash flows.

Oil and natural gas operations are often adversely affected by seasonal weather conditions, primarily during periods of severe weather or rainfall, and during periods of extreme cold. Power outages and other damages resulting from tornados, ice storms, flooding and other strong storms or weather events may prevent wells from being operated in an optimal manner. These weather conditions may reduce oil and natural gas production, which could adversely impact our cash flows.

Our oil and natural gas properties may be exposed to unanticipated water disposal or processing costs.

Where water produced from properties fails to meet the quality requirements of applicable regulatory agencies or wells produce water in excess of the applicable volumetric permit limit, the wells may have to be shut in or upgraded for water handling or treatment. The costs to treat or dispose of this produced water may increase if any of the following occur:

- permits cannot be renewed or obtained from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- the wells produce excess water; or
- new laws and regulations require water to be disposed of or treated in a different manner.

Risks Related to Our Midstream and Production Businesses

As a non-operator, our development of successful operations relies extensively on third-parties, including Mesquite and Targa, which could adversely affect our business, financial condition and results of operations.

We have only participated in wells, leasehold acreage and midstream assets operated by third parties, including Mesquite and Targa. The success of our business operations depends on the success of such operators. If our operators are not successful in the development, exploitation, production and operating activities relating to our midstream and production businesses, or are unable or unwilling to perform, it could adversely affect our business, financial condition and results of operations.

The insolvency of an operator of any of our properties or assets, the failure of an operator of any of our properties or assets to adequately perform operations or an operator’s breach of applicable agreements could reduce our production and revenue and result in our liability to governmental authorities for compliance with environmental, safety and other regulatory requirements, to the operator's suppliers and vendors and to royalty owners under oil and gas leases jointly owned with the operator or another insolvent owner.

Our operators will make decisions in connection with their operations (subject to their contractual and legal obligations), which may not be in our best interests and could have a material adverse effect on our business, financial condition and results of operations.

Risks Related to Financing and Credit Environment

Our independent registered public accounting firm has expressed doubt about our ability to continue as a going concern.

Our historical consolidated financial statements have been prepared under the assumption that we will continue as a going concern. The report on our audited consolidated financial statements for the year ended December 31, 2020 issued by our independent registered public accounting firm included in this Form 10-K includes an explanatory paragraph referring to the Credit Agreement being a current liability that matures on September 30, 2021 and expressing substantial doubt in our ability to continue as a going concern. Our ability to continue as a going concern is dependent upon our ability to either (i) refinance or extend the maturity of the Credit Agreement, or (ii) obtain adequate new debt or equity financing to repay the Credit Agreement in full at maturity. Our consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty. However, if we are unable to refinance or extend the maturity of the Credit Agreement, or otherwise raise adequate funds prior to the maturity date, it will further raise substantial doubt about our ability to continue as a going concern. The doubt regarding our potential ability to continue as a going concern may adversely affect our ability to obtain new financing on reasonable terms or at all. Additionally, if we are unable to continue as a going concern, our unitholders may lose some or all of their investment in us.

Our Credit Agreement has substantial prepayment requirements, other restrictions and financial covenants and requires periodic borrowing base redeterminations.

We depend on the Credit Agreement for future capital needs. The Credit Agreement restricts our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations. Additionally, the initial aggregate commitment amount is subject to quarterly $10.0 million principal and other mandatory prepayments. We are also required to comply with certain financial covenants and ratios. Our ability to comply with these restrictions, requirements and covenants in the future is uncertain and will be affected by the levels of cash flows from our operations and events or circumstances beyond our control, including events and circumstances that may stem from the condition of financial markets and commodity price levels. Our failure to comply with any of the prepayment requirements, or other restrictions and covenants under the Credit Agreement could result in an event of default, which could cause all of our existing indebtedness to become immediately due and payable. Each of the following is also an event of default:

- failure to pay any principal when due or any interest, fees or other amount prior to the expiration of certain grace periods;
- a representation or warranty made under the loan documents or in any report or other instrument furnished thereunder is incorrect when made;
- failure to perform or otherwise comply with the covenants in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- any event that permits or causes the acceleration of the indebtedness;
- bankruptcy or insolvency events involving us or our subsidiaries;
- certain changes in control as specified in the covenants to the Credit Agreement;

- the entry of, and failure to pay, one or more adverse judgments in excess of $2.5 million or one or more non-monetary judgments that could reasonably be expected to have a material adverse effect and for which enforcement proceedings are brought or that are not stayed pending appeal; and

- specified events relating to our employee benefit plans that could reasonably be expected to result in liabilities in excess of $2.5 million in any year.

- failure to comply with the Transaction Covenant (as defined below).

The Credit Agreement will mature on September 30, 2021. We may not be able to renew or replace the facility at similar borrowing costs, terms, covenants, restrictions or borrowing base, or with similar debt issue costs.

The amount available for borrowing at any one time under the Credit Agreement is limited to the separate borrowing bases associated with our oil and natural gas properties and our midstream assets. The borrowing base for the credit available for the upstream oil and natural gas properties is re-determined semi-annually in the second and fourth quarters of the year, and may be re-determined at our request more frequently and by the lenders, in their sole discretion, based on reserve reports as prepared by petroleum engineers, using, among other things, the oil and natural gas pricing prevailing at such time. The borrowing base for the credit available for our midstream properties is equal to the rolling four quarter EBITDA of our midstream operations multiplied by 4.5. Outstanding borrowings in excess of our borrowing base must be repaid or we must pledge other oil and natural gas properties as additional collateral. We may elect to pay any borrowing base deficiency in three equal monthly installments such that the deficiency is eliminated in a period of three months. Any increase in our borrowing base must be approved by all of the lenders.

Our Credit Agreement contains a condition to borrowing and a representation that no material adverse effect has occurred, which includes, among other things, a material adverse change in, or material adverse effect on the business, operations, property, liabilities (actual or contingent) or condition (financial or otherwise) of us and our subsidiaries who are guarantors taken as a whole. If a material adverse effect were to occur, we would be prohibited from borrowing under the Credit Agreement and we would be in default under the Credit Agreement, which could cause all of our existing indebtedness to become immediately due and payable.

The Tenth Amendment contains a new covenant (the “Transaction Covenant”), which provides that we must either (i) engage an investment bank, advisory firm or “sell-side” oil and gas midstream acquisition and divestiture firm (an “Advisory Firm”) to advise us with respect to a possible strategic transaction, which may include a sale of properties or equity interests, an issuance of equity interests in us or a subsidiary or a debt financing transaction (each, a “Qualifying Transaction”), or, (ii) without an Advisory Firm, take material steps towards engaging in a Qualifying Transaction. If we engage an Advisory Firm, then the target closing date for a Qualifying Transaction must be no later than August 31, 2021. If we take material steps on our own, then the target closing date for a Qualifying Transaction must be on or before June 30, 2021 or we must hire an Advisory Firm. In either event, the net cash proceeds must be reasonably expected to be greater than the full amount due under the Credit Agreement on the maturity date. If we are unable to comply with the Transaction Covenant it will be deemed an immediate event of default under the Credit Agreement, which could cause all of our existing indebtedness to become immediately due and payable. Any failure to comply with the Transaction Covenant could have a material and adverse effect on our business, liquidity and cash flows.

We may not be able to extend, replace or refinance our Credit Agreement on terms reasonably acceptable to us, or at all, which could materially and adversely affect our business, liquidity, cash flows and prospects.

Our Credit Agreement matures on September 30, 2021. We may not be able to extend, replace or refinance our existing Credit Agreement on terms reasonably acceptable to us, or at all, with our existing syndicate of banks or with replacement banks. In addition, we may not be able to access other external financial resources sufficient to enable us to repay the debt outstanding under our Credit Agreement upon its maturity. Any of the foregoing could materially and adversely affect our business, liquidity, cash flows and prospects.

Changes in LIBOR reporting practices or the method in which LIBOR is determined may adversely affect the market value of our current or future debt obligations, including obligations under our Credit Agreement.

As of March 16, 2021, we had $104.5 million of debt outstanding under our Credit Agreement that bears interest at variable rates that use the London Interbank Offered Rate ("LIBOR"), as a benchmark rate. On July 27, 2017, the Financial Conduct Authority (the "FCA"), which regulates LIBOR, announced that it intends to stop persuading or compelling banks to submit LIBOR quotations after 2021. The Alternative Reference Rates Committee, a steering committee consisting of large U.S. financial institutions convened by the U.S. Federal Reserve Board and the Federal Reserve Bank of New York, has recommended replacing LIBOR with the Secured Overnight Financing Rate (SOFR), an index supported by short-term Treasury repurchase agreements. On November 30, 2020, ICE Benchmark Administration ("IBA"), the administrator of USD LIBOR announced that it does not intend to cease publication of the remaining USD LIBOR tenors until June 30, 2023, providing additional time for existing contracts that are dependent on LIBOR to mature.

Under our Credit Agreement, if (a) the administrative agent determines that reasonable means do not exist for ascertaining LIBOR and such circumstances are unlikely to be temporary, (b) the supervisor for the administrator of LIBOR or another governmental authority having jurisdiction over the administrative agent has made a public statement identifying a date after which LIBOR shall no longer be used, or (c) new syndicated loans have started to adopt a new benchmark interest rate, then we will be required to negotiate an amendment to our Credit Agreement with the administrative agent. The use of the alternative benchmark interest rate under any such amendment may result in interest obligations which are more than or do not otherwise correlate over time with the payments that would have been made on such debt if LIBOR was available in its current form. Further, the same costs and risks that may lead to the discontinuation or unavailability of LIBOR may make one or more of the alternative methods impossible or impracticable to determine. At this time, it is not possible to predict the effect of any establishment of any alternative benchmark rate(s) and we cannot predict what alternative benchmark rate(s) will be utilized. Any new benchmark rate will likely not replicate LIBOR exactly, and any changes to benchmark rates may have an uncertain impact on our cost of funds under our Credit Agreement. Any of these proposals or consequences could have a material adverse effect on our financing costs.

We will be required to make substantial capital expenditures to increase our asset base. If we are unable to obtain needed capital or financing on satisfactory terms, our cash flows may be diminished or our financial leverage could increase.

In order to increase our asset base, we will need to make expansion capital expenditures. If we do not make sufficient or effective expansion capital expenditures, we will be unable to expand our business operations which may diminish our cash flows. To fund our expansion capital expenditures and investment capital expenditures, we will be required to use cash from our operations or incur borrowings. Alternatively, we may sell additional common units or other securities to fund our capital expenditures. Our ability to obtain bank financing or our ability to access the capital markets for future equity or debt offerings may be limited by our financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by general economic conditions, contingencies and uncertainties that are beyond our control. Even if we are successful in obtaining the necessary funds, the terms of such financings could implement restrictions or limitations on our ability to pay cash distributions. For example, our Credit Agreement currently prohibits us from making distributions to our common unitholders. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional limited partner interests may result in significant unitholder dilution and would increase the aggregate amount of cash required to make cash distributions to our unitholders in the future, if any, which could materially decrease our ability to pay cash distributions. Stonepeak is not contractually committed to providing any direct or indirect support to fund our growth.

Our ability to access the capital and credit markets to raise capital and borrow on favorable terms will be affected by disruptions in the capital and credit markets, which could adversely affect our operations, our ability to make acquisitions and our ability to pay cash distributions.

Disruptions in the capital and credit markets could limit our ability to access these markets or significantly increase our cost to borrow. Some lenders may increase interest rates, enact tighter lending standards, refuse to refinance existing debt at maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital markets on favorable terms, our ability to make acquisitions and pay cash distributions could be affected.

We are exposed to credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers, vendors, lenders in our Credit Agreement and counterparties to our hedging arrangements. Some of our customers, vendors, lenders and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Despite our credit review and analysis, we may experience financial losses in our dealings with these and other parties with whom we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our customers, vendors, lenders or counterparties could have a material adverse impact on our business, financial condition, results of operations or cash flows.

Our future debt levels may limit our flexibility to obtain additional financing and pursue other business opportunities.

We may incur substantial additional indebtedness in the future under our Credit Agreement or otherwise. Our future indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, maintenance and investment capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;
- covenants and financial tests contained in our existing and future credit and debt instruments may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- increased cash flows required to make principal and interest payments on our indebtedness could reduce the funds that would otherwise be available to fund operations, capital expenditures, future business development or any cash distributions; and
- our debt level may make us more vulnerable than our competitors with less debt to competitive pressures or a downturn in our business or the economy generally.

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, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future debt, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness, or seeking additional equity capital or bankruptcy protection. We may not be able to affect any of these remedies on satisfactory terms or at all.

Periods of inflation or stagflation, or expectations of inflation or stagflation, could increase our costs and adversely affect our business and operating results.

During periods of inflation or stagflation, our costs of doing business could increase, including increases in the variable interest rates that we pay on amounts we borrow under our Credit Agreement. We have not hedged any of our expected production volumes for 2021, and as a result, the cash flows generated by that future production will be subject to the impact of inflation or stagflation. If any of our operating, administrative or capital costs were to increase as a result of inflation or increase in the cost of goods and services, such a cap could have a material adverse effect on our business, financial condition, results of operations, and cash flows.

An increase in interest rates may cause the market price of our common units to decline and may increase our borrowing costs.

Like all equity investments, an investment in our common units is subject to certain risks. In exchange for accepting these risks, investors may expect to receive a higher rate of return than would otherwise be obtainable from lower-risk investments. Accordingly, as interest rates rise, the ability of investors to obtain higher risk-adjusted rates of return by purchasing government-backed debt or other interest-bearing securities may cause a corresponding decline in demand for riskier investments generally, including equity investments such as publicly-traded limited partnership interests. Reduced demand for our common units resulting from investors seeking other more favorable investment opportunities may cause the trading price of our common units to decline.

Higher interest rates may also increase the borrowing costs associated with our Credit Agreement. If our borrowing costs were to increase, our interest payments on our debt may increase, which would reduce the amount of cash available for our operating or capital activities.

Risks Related to Our Cash Distributions

Our partnership agreement prohibits us from making certain distributions until all of the Class C Preferred Units are redeemed and, as a result, our ability to make, maintain and grow cash distributions to common unitholders is dependent on our ability to redeem the Class C Preferred Units.

Under the terms of our partnership agreement, until the first quarter in which no Class C Preferred Units remain outstanding, we are not permitted to declare or make any distributions, redemptions or repurchases in respect of, among other partnership interests, our common units. As of January 1, 2021, our partnership agreement provides us with the ability to redeem the Class C Preferred Units without a premium to the liquidation preference of the Class C Preferred Units. If we are unable to access the capital markets on favorable terms or otherwise secure debt or equity financing to redeem the Class C Preferred Units, our ability to redeem the Class C Preferred Units and then to make, maintain and grow cash distributions to common unitholders will be materially adversely affected.

Our Credit Agreement restricts us from paying any distributions on our outstanding common units.

We do not have the ability to pay distributions to our common unitholders under our Credit Agreement other than in certain limited circumstances set forth in the Credit Agreement.

Any termination of the Shared Services Agreement requiring the payment of a termination fee may result in substantial dilution and could adversely affect our financial condition, results of operations, operating cash flows and any ability to pay cash distributions.

As previously disclosed and described in more detail in "Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Stonepeak Transactions," SP Holdings began engaging in non-binding discussions with the Board about terminating or, alternatively, amending and restating the Shared Services Agreement. If the Shared Services Agreement is terminated, and such termination ultimately requires the payment of a termination fee in cash, which we estimate was in excess of $35.0 million as of December 31, 2020, it could adversely affect our financial condition, results of operations and cash flows. If the Shared Services Agreement is terminated and such termination ultimately requires the payment of a termination fee in common units, then holders of our common units will experience substantial dilution.

If we do not complete expansion projects or make and integrate acquisitions, our future growth may be limited.

Our ability to enhance our financial position depends, in part, on our ability to complete expansion projects and make acquisitions that result in an increase in cash generated. We may be unable to complete successful, accretive expansion projects or acquisitions for any of the following reasons:

- we are outbid by competitors for potential acquisition candidates;
- we are unable to identify attractive expansion projects or acquisition candidates;
- we are unable to obtain necessary rights-of-way or governmental approvals, including from regulatory agencies;
- we are unable to successfully integrate the businesses that we develop or acquire;
- we are unable to obtain financing for such expansion projects or acquisitions on economically acceptable terms, or at all;

- we do not make accurate assumptions about potential volumes, reserves, revenues and costs, including synergies and growth; or
- we are unable to secure adequate customer commitments to use the newly developed or acquired facilities.

Oil and natural gas prices are very volatile. If commodity prices decline significantly for a temporary or prolonged period, our cash from operations may decline and may adversely affect our financial condition, our results of operations, our profitability and our ability to invest in new midstream facilities.

Our revenue, profitability and operating cash flows depend in part upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. Changes in oil and natural gas prices have a significant impact on the value of our reserves and on our operating cash flows and may also impact the fees generated by us from our midstream facilities. In particular, declines in commodity prices will directly reduce the value of our reserves, our operating cash flows, our ability to borrow money or raise capital and may indirectly reduce the cash flows from our midstream facilities. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and level of foreign imports of oil and natural gas;
- the level of consumer product demand;
- weather conditions;
- overall domestic and global economic conditions;
- political and economic conditions in oil and natural gas producing countries, including those in West Africa, the Middle East and South America;
- the ability of members of OPEC to agree to and maintain oil price and production controls;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the costs, proximity and capacity of oil and natural gas pipelines and other transportation facilities;
- the price and availability of alternative fuels; and
- the increase in the supply of natural gas due to the development of natural gas.

In the past, the prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. If commodity prices decline significantly for a temporary or prolonged period, our cash from operations may decline and may adversely affect our financial condition, our results of operations, our profitability and our ability to invest in new midstream facilities.

Acquisitions involve potential risks that could adversely affect our business, financial condition and results of operations.

Any acquisition involves potential risks, including, among other things:

- the risk of title defects discovered after closing;
- inaccurate assumptions about revenues and costs, including synergies;
- significant increases in our indebtedness and working capital requirements;
- an inability to transition and integrate successfully or timely the businesses we acquire;
- the cost of transition and integration of data systems and processes;
- potential environmental problems and costs;
- the assumptions of unknown liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management's attention from other business concerns;
- increased demands on existing personnel and on our organizational structure;
- disputes arising out of acquisitions;
- customer or key employee losses of the acquired businesses; and
- the failure to realize expected growth or profitability.

The scope and cost of these risks may ultimately be materially greater than estimated at the time of the acquisition. Furthermore, our future acquisition costs may be higher than those we have achieved historically. Any of these factors could adversely affect our business, financial condition and results of operations.

Inadequate insurance could have a material adverse impact on our business, financial condition and results of operations.

We ordinarily maintain insurance against certain losses and liabilities arising from our operations; however, insurance against all operational risks is not available to us and we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Additionally, our insurance program may include a number of insurance carriers. Significant disruptions in financial markets could lead to a deterioration in the financial condition of many financial institutions, including insurance companies; therefore, we may not be able to obtain the full amount of our insurance coverage for insured events. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business, financial condition and results of operations.

Risks Related to Regulatory Compliance

Potential regulatory actions could increase our operating or capital costs and delay our operations or otherwise alter the way we conduct our business.

Our business activities are subject to extensive federal, state, and local regulations. Changes to existing regulations or new regulations may unfavorably impact us, our suppliers or our customers. In the United States, legislation that directly impacts the oil and natural gas industry has been proposed covering areas such as emission reporting and reductions, hydraulic fracturing of wells, the repeal of certain oil and natural gas tax incentives and tax deductions and the treatment and disposal of produced water. The EPA has also ruled that carbon dioxide, methane and other greenhouse gases endanger human health and the environment. This allows the EPA to adopt and implement regulations restricting greenhouse gases under existing provisions of the federal Clean Air Act. In addition, provisions of the Dodd-Frank Act, which regulate financial derivatives, may impact our ability to enter into derivatives or require burdensome collateral or reporting requirements. These and other potential regulations could increase our costs, reduce our liquidity, impact our ability to hedge our future oil and natural gas sales, delay our operations or otherwise alter the way that we conduct our business, negatively impacting our financial condition, results of operations and cash flows.

We are subject to federal, state, and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the production and transportation of oil and natural gas. The possibility exists that any new laws, regulations or enforcement policies could be more stringent than existing laws and could significantly increase our compliance costs.

Our failure to obtain or maintain necessary permits could adversely affect our operations.

Our operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or leases could have a material adverse effect on our ability to develop our properties. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil and natural gas we may produce and sell.

Increased regulation of hydraulic fracturing could result in reductions or delays in the production of natural gas, NGLs and oil by Mesquite, which could reduce the throughput on our facilities and adversely impact our revenues.

A substantial portion of Mesquite's production of natural gas, NGLs and oil is being developed from unconventional sources, such as shale formations. These reservoirs require hydraulic fracturing completion processes to release the liquids and natural gas from the rock so it can flow through casing to the surface. Hydraulic fracturing is a well stimulation process that utilizes large volumes of water and sand (or other proppant) combined with fracturing chemical additives that are pumped at high pressure to crack open previously impenetrable rock to release hydrocarbons. Hydraulic fracturing is typically regulated by state oil and gas commissions and similar agencies. Various studies are currently underway by the EPA and other federal and state agencies concerning the potential environmental impacts of hydraulic fracturing activities. For example, the EPA issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act in 2014 requesting comments related to disclosures for hydraulic fracturing chemicals. At the same time, certain environmental groups have suggested that additional laws may be needed to more closely and uniformly regulate the hydraulic fracturing process, and legislation has been proposed by some members of the U.S. Congress to provide for such regulation. We cannot predict whether any such legislation will ever be enacted and if so, what its provisions would be. Additionally, President Biden has declared that he would support federal government efforts to limit or prohibit hydraulic fracturing. These declarations include threats to take actions banning hydraulic fracturing of crude oil and natural gas wells and banning new leases for production of minerals on federal properties, including onshore lands and offshore waters. We cannot predict whether additional levels of regulations and permits will be required through the adoption of new laws and regulations at the federal or state level, and if so, what the provisions would be. If additional levels of regulation and permits were to be implemented through the adoption of new laws and regulations at the federal or state level, that could lead to delays and process prohibitions that could reduce the volumes of liquids and natural gas that move through our facilities, which in turn could materially adversely affect our revenues and results of operations.

We may incur significant liability under, or costs and expenditures to comply with, environmental and worker health and safety regulations, which are complex and subject to frequent change.

As an owner, lessee or operator of gathering pipelines and compressor stations, we are subject to various stringent federal, state and local laws and regulations relating to the discharge of materials into, and protection of, the environment. 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 response actions. These laws and regulations may impose numerous obligations that are applicable to our and our customer's 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 or our customers' operations, the imposition of specific standards addressing worker protection, and the imposition of substantial liabilities and remedial obligations for pollution or contamination resulting from our and our customer's operations. Failure to comply with these laws, regulations and permits may result in joint and several, strict liability and the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions limiting or preventing some or all of our operations.

Private parties, including the owners of the properties through which our facilities pass and facilities where wastes resulting from our operations are taken for reclamation or disposal, 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. We may not be able to recover all or any of these costs from insurance, the operators of our facilities and properties or other third parties. In addition, we may experience a delay in obtaining or be unable to obtain required permits, which may interrupt our operations and limit our growth and revenues, which in turn could affect our profitability. There is no assurance that changes in or additions to public policy regarding the protection of the environment will not have a significant impact on our operations and profitability.

The operation of our facilities also poses risks of environmental liability due to leakage, migration, releases or spills from our facilities to surface or subsurface soils, surface water or groundwater. Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability.

We may incur significant costs and liabilities as a result of pipeline integrity management program testing and any related pipeline repair or preventative or remedial measures.

The DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located where a leak or rupture could do the most harm in HCAs. The regulations require operators to:

- perform ongoing assessments of pipeline integrity;
- identify and characterize applicable threats to pipeline segments that could impact a high consequence area;
- improve data collection, integration and analysis;
- repair and remediate the pipeline as necessary; and
- implement preventive and mitigating actions.

The 2011 Pipeline Safety Act, among other things, increases the maximum civil penalty for pipeline safety violations and directs the Secretary of Transportation to promulgate rules or standards relating to expanded integrity management requirements, automatic or remote-controlled valve use, excess flow valve use, leak detection system installation and testing to confirm the material strength of pipe operating above 30% of specified minimum yield strength in high consequence areas. Should our facilities fail to comply with DOT or comparable state regulations, we could be subject to substantial penalties and fines.

PHMSA has also published advanced notices of proposed rulemaking and notices of proposed rulemaking to solicit comments on the need for changes to its safety regulations as well as advisory bulletins. In April 2016, PHMSA issued a notice of proposed rulemaking that would expand integrity management requirements and impose new pressure requirements on currently regulated gas transmission pipelines and would also significantly expand the regulation of gas gathering lines, subjecting previously unregulated pipelines to requirements regarding damage prevention, corrosion control, public education programs, maximum allowable operating pressure limits and other requirements. In addition, in 2012, PHMSA issued an advisory bulletin providing guidance on the verification of records related to pipeline maximum allowable operating pressure, which could result in additional requirements for the pressure testing of pipelines or the reduction of maximum operating pressures. The adoption of these and other laws or regulations that apply more comprehensive or stringent safety standards could require us to install new or modified safety controls, pursue new capital projects, or conduct maintenance programs on an accelerated basis, all of which could require us to incur increased operational costs that could be significant. While we cannot predict the outcome of legislative or regulatory initiatives, such legislative and regulatory changes could have a material effect on our cash flows. Please read “Item 1. Business—Governmental Regulation—Pipeline Safety Regulation” for more information.

Because we handle oil, natural gas and other petroleum products in our business, we may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental regulations.

The operations of our wells, gathering systems, processing facilities, pipelines and other facilities are subject to stringent and complex federal, state and local environmental laws and regulations. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations. There is an inherent risk that we may incur environmental costs and liabilities due to the nature of our business and the substances we handle. Certain environmental statues, including RCRA, CERCLA and analogous state laws and regulations, impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed of or otherwise released. In addition, an accidental release from one of our facilities 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.

Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary, and these costs may not be recoverable from insurance.

Risks Inherent in an Investment in Our Common Units

We are currently not in compliance with the NYSE American listing standards. If our common units are delisted, it could result in even further reductions in the trading price and liquidity of our common units, which could materially adversely affect our ability to raise capital or pursue strategic transactions on acceptable terms, or at all.

Our common units are currently listed on the NYSE American. Continued listing of a security on the NYSE American is conditioned upon compliance with various continued listing standards. On April 3, 2020, we received notice (the “Notice”) from the NYSE American stating that we were below compliance with the continued listing standards as set forth in Part 10 of the NYSE American Company Guide (the “Company Guide”). The Notice provided that the NYSE American’s review of the Partnership showed that we were below compliance with Section 1003(a)(i) of the Company Guide.

The Notice had no immediate effect on our listing on the NYSE American and, therefore, our common units are still listed on the NYSE American, subject to our compliance with other continued listing requirements of the NYSE American. On May 4, 2020, we submitted a plan of compliance (the “Plan”) to the NYSE American addressing how we intend to regain compliance with Section 1003(a)(i) of the Company Guide by October 3, 2021. On June 25, 2020 the Partnership received a letter from the NYSE American stating that the Partnership’s Plan had been accepted and that the Partnership had been granted a plan period through October 3,2021 (the period of time from May 4, 2020 to October 3, 2021 (the “Plan Period”).

By October 3, 2021, we must either be in compliance with Section 1003(a)(i) of the Company Guide or must have made progress that is consistent with the Plan during the Plan Period. In addition, during the Plan Period, we must provide quarterly updates to the NYSE American concurrent with our interim and annual SEC filings. Failure to meet the requirements to regain compliance could result in the initiation of delisting proceedings.

The Notice does not affect our business operations or our reporting obligations under the rules and regulations of the SEC, nor does the Notice conflict with or cause an event of default under any of our material agreements.

If we cannot meet the NYSE American continued listing requirements by the end of the Plan Period, or if the NYSE American is not otherwise satisfied with our progress as of the end of the Plan Period, the NYSE American may delist our common units resulting in our common units trading in the less liquid over-the-counter market, which could have an adverse effect on us and the liquidity and market price of our common units. The delisting of our common units from the NYSE American could result in even further reductions in the trading price of our common units, substantially limit the liquidity of our common units, and materially adversely affect our ability to raise capital or pursue strategic restructuring, refinancing or other transactions on acceptable terms, or at all. Delisting from the NYSE American could also have other negative results, including the potential loss of confidence by vendors and employees, the loss of institutional investor interest and fewer business development opportunities. Our management is considering alternatives to ensure continued compliance with the NYSE American listing standards, but there is no assurance that we will continue to maintain compliance with the NYSE American continued listing standards.

Certain events may result in our general partner exercising its limited call right, which may require common unitholders to sell their common units at an undesirable time or price.

As of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) the Warrant that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights. Stonepeak also owns 100% of the issued and outstanding equity interests in SP Holdings, which is the sole member of our general partner. Pursuant to Section 15.1 of our partnership agreement, if at any time Stonepeak holds more than 80% of our outstanding common units and completes the Stonepeak LCR Transfer (as defined in "Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Stonepeak Transactions), Stonepeak will be able to cause our general partner or a controlled affiliate of our general partner to exercise its right to acquire all, but not less than all, of our common units held by persons other than our general partner and its controlled affiliates at a price equal to the greater of (1) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the limited call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its controlled affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Common unitholders may also incur tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of common units to be repurchased upon exercise of the limited call right. Furthermore, there is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units, including common units issued pursuant to the Stonepeak Letter Agreement (as defined in "Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Stonepeak Transactions) or as a result of the termination or renegotiation of the Shared Services Agreement, and then exercising its limited call right. If our general partner exercises its limited call right, the effect would be to take the Partnership private and, if the common units are subsequently deregistered, the Partnership will no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended.

Stonepeak Catarina and its affiliates, including our general partner, will have conflicts of interest with us. They will not owe any fiduciary duties to us or our common unitholders, but instead will owe us and our common unitholders limited contractual duties, and they may favor their own interests to the detriment of us and our other common unitholders.

Stonepeak Catarina, through its ownership of SP Holdings, owns and controls our general partner and, through the Representation and Standstill Agreement (as defined below) and its ownership of SP Holdings, has the power to appoint all of the directors of our general partner. Although our general partner has a duty to manage us in a manner that is not adverse to us and our unitholders, the directors and officers of our general partner have a fiduciary duty to manage our general partner in a manner that is beneficial to SP Holdings and its affiliates, including Stonepeak Catarina. Conflicts of interest will arise between Stonepeak Catarina and its affiliates, including our general partner, on the one hand, and us and our unitholders, on the other hand. In resolving these conflicts of interest, our general partner may favor its own interests and the interests of Stonepeak over our interests and the interests of our unitholders. These conflicts include the following situations, among others:

- Neither our partnership agreement nor any other agreement requires Stonepeak to pursue a business strategy that favors us or utilizes our assets. The directors and officers of SP Holdings and its affiliates, including Stonepeak Catarina, have a fiduciary duty to make these decisions in the best interests of the members of SP Holdings and its affiliates, which may be contrary to our interests. Stonepeak may choose to shift the focus of its investment and growth to areas not served by our assets.
- Our general partner is allowed to take into account the interests of parties other than us, such as Stonepeak Catarina and SP Holdings, in resolving conflicts of interest.
- SP Holdings and its affiliates, including Stonepeak Catarina, may be constrained by the terms of their respective debt instruments from taking actions, or refraining from taking actions, that may be in our best interests.
- Our partnership agreement replaces the fiduciary duties that would otherwise be owed by our general partner with contractual standards governing its duties, limit our general partner's liabilities and restrict the remedies available to our unitholders for actions that, without such limitations, might constitute breaches of fiduciary duty.
- Except in limited circumstances, our general partner has the power and authority to conduct our business without unitholder approval.
- Disputes may arise under our commercial agreements with SP Holdings and its affiliates, including Stonepeak Catarina.
- Our general partner determines the amount and timing of asset purchases and sales, borrowings, issuances of additional partnership units and the creation, reduction or increase of cash reserves, each of which can affect the amount of cash available for distribution.
- Our general partner determines the amount and timing of any capital expenditures and whether a capital expenditure is classified as a maintenance capital expenditure, which will reduce operating surplus, or an expansion or investment capital expenditure, which will not reduce operating surplus. This determination can affect the amount of cash that is distributed.
- Our general partner determines which costs incurred by it are reimbursable by us, the amount of which is not limited by our partnership agreement.
- Our general partner may cause us to borrow funds in order to permit the payment of cash distributions, even if the purpose or effect of the borrowing is to make incentive distributions.
- Our partnership agreement permits us to classify up to $20.0 million as operating surplus, even if it is generated from asset sales, non-working capital borrowings or other sources that would otherwise constitute capital surplus. This cash may be used to fund distributions to SP Holdings as the holder of the incentive distribution rights.
- Our partnership agreement does not restrict our general partner from causing us to pay it or its affiliates for any services rendered to us or entering into additional contractual arrangements with any of these entities on our behalf.
- Our general partner intends to limit its liability regarding our contractual and other obligations.
- Our general partner and its controlled affiliates may exercise their right to call and purchase all of the common units not owned by them if they own more than 80% of our common units.
- Our general partner controls the enforcement of the obligations that it and its affiliates owe to us, including the obligations of SP Holdings and Stonepeak Catarina under their commercial agreements with us.
- Our general partner decides whether to retain separate counsel, accountants or others to perform services for us.

- Our general partner may elect to cause us to issue common units to SP Holdings in connection with a resetting of the target distribution levels related to our incentive distribution rights without the approval of the Conflicts Committee or our unitholders. This election may result in lower distributions to our common unitholders in certain situations.

Our general partner and its affiliates, including SP Holdings and Stonepeak Catarina, may not allocate corporate opportunities to us.

Pursuant to the terms of our partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to our general partner or any of its affiliates, including SP Holdings, its executive officers and directors and Stonepeak Catarina. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for us does not have any duty to communicate or offer such opportunity to us. Any such person or entity will not be liable to us or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to us. This may create actual and potential conflicts of interest between us and affiliates of our general partner and result in less than favorable treatment of us and our common unitholders.

Our partnership agreement permits our general partner to redeem any partnership interests held by a limited partner who is an ineligible holder.

If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us or our subsidiaries, or we become subject to federal, state or local laws or regulations that create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, our general partner may redeem the units held by the limited partner at their current market price. In order to avoid any material adverse effect on rates charged or cancellation or forfeiture of property, our general partner may require each limited partner to furnish information about their U.S. federal income tax status or nationality, citizenship or related status. If a limited partner fails to furnish information about their U.S. federal income tax status or nationality, citizenship or other related status after a request for the information or our general partner determines after receipt of the information that the limited partner is not an eligible holder, our general partner may elect to treat the limited partner as an ineligible holder. An ineligible holder assignee does not have the right to direct the voting of their units and may not receive distributions in kind upon our liquidation.

The market price of our common units may fluctuate significantly, and you could lose all or part of your investment.

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

- the resolution of the Rejection Lawsuits and the closing or termination of the Settlement Agreement;
- provisions in our Credit Agreement which currently prohibit us from paying distributions to our common unitholders other than in certain limited circumstances set forth in our Credit Agreement;
- our quarterly or annual earnings or those of other companies in our industry;
- announcements by us or our competitors of significant contracts or acquisitions;
- changes in accounting standards, policies, guidance, interpretations or principles;
- general economic conditions, including interest rates and governmental policies impacting interest rates;
- the failure of securities analysts to cover our common units or changes in financial estimates by analysts;

- opinions and beliefs on the potential market price of our common units shared on social media channels, such as YouTube and Reddit;
- future sales of our common units;
- Stonepeak Catarina is able to elect to receive distributions on the Class C preferred Units in common units for any future quarter; and
- other factors described in this Form 10-K and the documents incorporated herein.

Our partnership agreement replaces our general partner's fiduciary duties to our common unitholders with contractual standards governing its duties.

Our partnership agreement contains provisions that eliminate the fiduciary standards to which our general partner would otherwise be held by state fiduciary duty law and replace those duties with several different contractual standards. For example, our partnership agreement permits our general partner to make a number of decisions in its individual capacity, as opposed to in its capacity as our general partner, free of any duties to us and our unitholders other than the implied contractual covenant of good faith and fair dealing, which means that a court will fill gaps under the partnership agreement to enforce the reasonable expectations of the partners, but only where the language in the partnership agreement does not provide for a clear course of action. This provision entitles our general partner to consider only the interests and factors that it desires and relieves it of any duty or obligation to give any consideration to any interest of, or factors affecting, us, our affiliates or our limited partners. Examples of decisions that our general partner may make in its individual capacity include:

- how to allocate business opportunities among us and its other affiliates;
- whether to exercise its limited call right;
- whether to seek approval of the resolution of a conflict of interest by the Conflicts Committee; and
- whether or not to consent to any merger or consolidation of the partnership or amendment to the partnership agreement.

Our partnership agreement restricts the remedies available to our common unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty.

The effect of eliminating fiduciary standards in our partnership agreement is that the remedies available to unitholders for actions taken by our general partner that might otherwise constitute breaches of fiduciary duty under state fiduciary duty law will be significantly restricted. For example, our partnership agreement provides that:

- whenever our general partner, the Board or any committee thereof (including the Conflicts Committee) makes a determination or takes, or declines to take, any other action in their respective capacities, our general partner, the Board and any committee thereof (including the Conflicts Committee), as applicable, is required to make such determination, or take or decline to take such other action, in good faith, and under our partnership agreement, a determination, other action or failure to act by our general partner and any committee thereof (including the Conflicts Committee) will be deemed to be in good faith unless the general partner, the Board or any committee thereof (including the Conflicts Committee) believed that such determination, other action or failure to act was adverse to the interests of the partnership or, with regard to certain determinations by the Board relating to the conflict transactions described below, the Board did not believe that the specified standards were met, and, except as specifically provided by our partnership agreement, neither our general partner, the Board nor any committee thereof (including the Conflicts Committee) will 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 or our limited partners 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, 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 (including any duties to us or our unitholders) if a transaction with an affiliate or the resolution of a conflict of interest is:

  - approved by the Conflicts Committee of the Board, although our general partner is not obligated to seek such approval;

  - approved by the vote of a majority of the outstanding common units, excluding any common units owned by our general partner and its affiliates;

  - determined by the Board to be on terms no less favorable to us than those generally being provided to or available from unrelated third parties; or

  - determined by the Board to be 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 determine 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 third and fourth sub-bullets above, then it will be presumed that, in making its decision, the Board acted in good faith, and in any proceeding brought by or on behalf of any limited partner or the partnership challenging such determination, the person bringing or prosecuting such proceeding will have the burden of overcoming such presumption.

Furthermore, if any limited partner, our general partner or any person holding any beneficial interest in us brings any claims, suits, actions or proceedings (including, but not limited to, those asserting a claim of breach of a fiduciary duty) and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such limited partner, our general partner or person holding any beneficial interest in us shall be obligated to reimburse us and our “affiliates,” as defined in Section 1.1 of our partnership agreement (including our general partner, the directors and officers of our general partner, and Stonepeak) for all fees, costs and expenses of every kind and description, including, but not limited to, all reasonable attorney’s fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding.

Our partnership agreement includes exclusive forum, venue and jurisdiction provisions and limitations regarding claims, suits, actions or proceedings. By taking ownership of a common unit, a limited partner is irrevocably consenting to these provisions and limitations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts.

Our partnership agreement is governed by Delaware law. Our partnership agreement includes exclusive forum, venue and jurisdiction provisions designating Delaware courts as the exclusive venue to the fullest extent permitted by applicable law for most claims, suits, actions and proceedings involving us or our officers, directors and employees and limitations regarding claims, suits, actions or proceedings. By taking ownership of a common unit, a limited partner is irrevocably consenting to these provisions and limitations regarding claims, suits, actions or proceedings and submitting to the exclusive jurisdiction of Delaware courts. If a dispute were to arise between a limited partner and us or our officers, directors or employees, the limited partner may be required to pursue its legal remedies in Delaware, which may be an inconvenient or distant location and which is considered to be a more corporate-friendly environment. Furthermore, if any limited partner, our general partner or person holding any beneficial interest in us brings any claims, suits, actions or proceedings (including, but not limited to, those asserting a claim of breach of a fiduciary duty) and such person does not obtain a judgment on the merits that substantially achieves, in substance and amount, the full remedy sought, then such limited partner, our general partner or person holding any beneficial interest in us shall be obligated to reimburse us and our affiliates, (as defined in our partnership agreement, which includes our general partner, the directors and officers of our general partner and Stonepeak) for all fees, costs and expenses of every kind and description, including, but not limited to, all reasonable attorneys' fees and other litigation expenses, that the parties may incur in connection with such claim, suit, action or proceeding. This provision may have the effect of increasing a unitholder's cost of asserting a claim and therefore, discourage lawsuits against us and our general partner's directors and officers. Because fee-shifting provisions such as these are relatively new developments in corporate and partnership law, the enforceability of such provisions are uncertain; in addition, future legislation could restrict or limit this provision of our partnership agreement and its effect of saving us and our affiliates from fees, costs and expenses incurred in connection with claims, actions, suits or proceedings.

Holders of our common units will have limited voting rights and will not be entitled to elect our general partner or its directors.

Our common unitholders have limited voting rights on matters affecting our business and, therefore, limited ability to influence management's and our general partner's decisions regarding our business. Common unitholders will have no right on an annual or ongoing basis to elect our general partner or the Board. Rather, the Board will be appointed by Stonepeak Catarina through its ownership of SP Holding. Furthermore, if common unitholders are dissatisfied with the performance of our general partner, they will have little ability to remove our general partner. As a result of these limitations, the price at which our common units will trade could be diminished because of the absence or reduction of a takeover premium in the trading price. Our partnership agreement also contains provisions limiting the ability of common unitholders to call meetings or to acquire information about our operations, as well as other provisions limiting our common unitholders' ability to influence the manner or direction of management.

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

Common unitholders' voting rights are further restricted by a provision of our partnership agreement providing that any units held by a person that owns 20% or more of any class of units then outstanding, other than our general partner, its affiliates, Stonepeak Catarina, their transferees and persons who acquired such units with the prior approval of the Board, cannot vote on any matter.

Our general partner interest or the control of our general partner may be transferred to a third-party without unitholder consent.

Our general partner is able to transfer its general partner interest to a third party in a merger or in a sale of all or substantially all of any assets it may own without the consent of our common unitholders. Furthermore, there is no restriction in the partnership agreement on the ability of SP Holdings to transfer its membership interest in our general partner to a third party. The new members of our general partner would then be in a position to replace the directors and officers of our general partner in order to control the decisions taken by the Board or such officers.

The incentive distribution rights held by SP Holdings may be transferred to a third party without unitholder consent.

SP Holdings is able to transfer its incentive distribution rights to a third party at any time without the consent of our common unitholders. If SP Holdings transfers its incentive distribution rights to a third party but retains its ownership interest in our general partner, our general partner may not have the same incentive to grow our partnership and increase quarterly distributions to unitholders over time as it would if SP Holdings had retained ownership of the incentive distribution rights.

We are able to issue additional units without common unitholder approval, which would dilute unitholder interests.

Our partnership agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to our common units that we may issue at any time 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 have the following effects:

- our existing limited partners' proportionate ownership interest in us will decrease;
- the amount of cash available for distribution on each limited partnership interest may decrease;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total cash available for distribution, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding limited partner interest may be diminished; and
- the market price of our common units may decline.

Our general partner intends to limit its liability regarding our obligations.

Our general partner intends to limit its liability under contractual arrangements so that the counterparties to such arrangements have recourse only against our assets and not against our general partner or its assets. Our general partner may therefore cause us to incur indebtedness or other obligations that are nonrecourse to our general partner. Our partnership agreement permits our general partner to limit its liability, even if we could have obtained more favorable terms without the limitation on liability. In addition, we are obligated to reimburse or indemnify our general partner to the extent that it incurs obligations on our behalf. Any such reimbursement or indemnification payments would reduce the amount of cash otherwise available for distribution to our unitholders.

Your 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 and outside of Delaware. 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. You could be liable for any and all of our obligations as if you were 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
- your 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.

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 Section 17-607 of the Delaware Revised Uniform Limited Partnership Act (the "Delaware Act"), we may not make a distribution to you 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. Transferees of common units are liable both for the obligations of the transferor to make contributions to the partnership that were known to the transferee at the time of transfer 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.

The NYSE American does not require a publicly traded limited partnership like us to comply with certain of its corporate governance requirements.

Because we are a publicly traded limited partnership, the NYSE American does not require us to have a majority of independent directors on the Board or to establish a compensation committee or a nominating and corporate governance committee. Accordingly, unitholders will not have the same protections afforded to certain corporations that are subject to all of the NYSE American corporate governance requirements.

Tax Risks

Our tax treatment depends on our status as a partnership for U.S. federal income tax purposes, as well as our not being subject to a material amount of entity-level taxation by states and localities. If the Internal Revenue Service ("IRS") were to treat us as a corporation for U.S. federal income tax purposes or if we were otherwise subject to a material amount of entity-level taxation, then our cash available for distribution would be substantially reduced.

The anticipated after-tax economic benefit of an investment in our common units depends largely on us being treated as a partnership for U.S. federal income tax purposes. Despite the fact that we are a limited partnership under Delaware law, we will be treated as a corporation for U.S. federal income tax purposes unless we satisfy a "qualifying income" requirement. Based on our current operations, we believe that we satisfy the qualifying income requirement and will continue to be treated as a partnership for U.S. federal income tax purposes. Failure to meet the qualifying income requirement or a change in current law could cause us to be treated as a corporation for U.S. federal income tax purposes or otherwise subject us to taxation as an entity. We have not requested, and do not plan to request, a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes.

If we were treated as a corporation for U.S. federal income tax purposes, we would pay U.S. federal income tax on our taxable income at the corporate income tax rate, and we would also likely pay additional state and local income taxes at varying rates. Distributions to unitholders would generally be taxed again as corporate dividends (to the extent of our current and accumulated earnings and profits as determined for U.S. federal income tax purposes), and no income, gains, losses, deductions or credits recognized by us would flow through to the unitholders. Because a tax would be imposed on us as a corporation, our cash available for distribution to our unitholders would be reduced.

At the state level, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of a material amount of any these taxes in the jurisdictions in which we own assets or conduct business could substantially reduce the cash available for distribution to our unitholders.

If we were treated as a corporation for U.S. federal income tax purposes or otherwise subjected to a material amount of entity-level taxation, there would be a material reduction cash flows and after-tax return to our unitholders likely causing a substantial reduction in the value of our common units.

Our partnership agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects us to taxation as a corporation or otherwise subjects us to entity-level taxation for U.S. federal, state or local income tax purposes, the minimum quarterly distribution and the target distributions may be adjusted to reflect the impact of that law on us.

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

The present U.S. federal income tax treatment of publicly traded partnerships, including us, or an investment in our common units may be modified by administrative or legislative changes or differing judicial interpretation at any time. For example, from time to time members of the U.S. Congress have proposed and considered substantive changes to the existing U.S. federal income tax laws that would affect publicly traded partnerships. In addition, the Treasury Department has issued, and in the future may issue, regulations interpreting those laws that affect publicly traded partnerships. We believe the income that we treat as qualifying satisfies the requirements under current regulations. However, there can be no assurance that there will not be further changes to U.S. federal income tax laws or the Treasury Department's interpretation of the qualifying income rules in a manner that could impact our ability to qualify as a partnership for U.S. federal income tax purposes in the future.

We are unable to predict whether legislation or other tax-related proposals will ultimately be enacted. Any modification to the U.S. federal income tax laws and interpretations thereof may or may not be applied retroactively and could make it more difficult or impossible for us to meet the exception for certain publicly traded partnerships to be treated as a partnership for U.S. federal income tax purposes. Any such change could negatively impact the value of an investment in our common units.

Our common unitholders' share of our income will be taxable to them even if they do not receive any cash distributions from us.

Common unitholders are required to pay U.S. federal income and other taxes and, in some cases, state and local income taxes, on their share of our taxable income, whether or not they receive cash distributions from us. Our Credit Agreement and partnership agreement currently prohibit us from paying distributions to our common unitholders. As a result, for the foreseeable future our common unitholders will not receive cash distributions from us equal to their share of our taxable income or even equal to the actual tax liability due from them with respect to that income.

If the IRS contests the U.S. federal income tax positions we take, the market for our common units may be adversely impacted, and our cash available for distribution might be substantially reduced.

We have not requested a ruling from the IRS with respect to our treatment as a partnership for U.S. federal income tax purposes or any other matter affecting us. The IRS may adopt positions that differ from the positions we take. It may be necessary to resort to administrative or court proceedings to sustain some or all of the positions we take, and a court may disagree with some or all of those positions. Any contest with the IRS may materially and adversely impact the market for our common units and the price at which they trade. In addition, our costs of any contest with the IRS will result in a reduction in cash available for distribution and thus will be borne indirectly by our unitholders.

Pursuant to legislation applicable for partnership tax years beginning after 2017 if the IRS makes audit adjustments to our partnership tax returns, it may assess and collect any taxes (including any applicable penalties or interest) resulting from such audit adjustments directly from us. To the extent possible under these new rules, our general partner may elect to either pay the taxes (including any applicable penalties and interest) directly to the IRS in the year in which the audit is completed, or, if we are eligible, issue a revised information statement to each current and former unitholder with respect to an audited and adjusted partnership tax return. Although our general partner may elect to have our current and former unitholders take such audit adjustment into account and pay any resulting taxes (including applicable penalties or interest) in accordance with their interests in us during the tax year under audit, there can be no assurance that such election will be practical, permissible or effective in all circumstances. If we make payments of taxes and any penalties and interest directly to the IRS in the year in which the audit is completed, our cash available for distribution might be substantially reduced, in which case our current unitholders may bear some or all of the tax liability resulting from such audit adjustment even if the unitholders did not own units in us during the tax year under audit.

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

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

Unitholders may be subject to limitations on their ability to deduct interest expense we incur.

Our ability to deduct business interest expense is limited for U.S. federal income tax purposes to an amount equal to the sum of our business interest income and a specified percentage of our "adjusted taxable income" during the taxable year, computed without regard to any business interest income or expense, and in the case of taxable years beginning before 2022, any deduction allowable for depreciation, amortization, or depletion. Business interest expense that we are not entitled to fully deduct will be allocated to each unitholder as excess business interest and can be carried forward by the unitholder to successive taxable years and used to offset any excess taxable income allocated by us to the unitholder. Any excess business interest expense allocated to a unitholder will reduce the unitholder's tax basis in its partnership interest in the year of the allocation even if the expense does not give rise to a deduction to the unitholder in that year.

Tax-exempt entities face unique tax issues from owning common units that may result in adverse tax consequences to them.

Investment in common units by tax-exempt entities, including employee benefit plans and individual retirement accounts (known as IRAs), raises issues unique to them. For example, virtually all of our income allocated to organizations exempt from U.S. federal income tax, including IRAs and other retirement plans, will be unrelated business taxable income and will be taxable to them. Tax-exempt entities with multiple unrelated trades or businesses cannot aggregate losses from one unrelated trade or business to offset income from another to reduce total unrelated business taxable income. As a result, it may not be possible for tax-exempt entities to utilize losses from an investment in us to offset unrelated business taxable income from another unrelated trade or business and vice versa. Tax-exempt entities should consult a tax advisor before investing in our common units.

Non-U.S. unitholders will be subject to U.S. federal income taxes and withholding with respect to income and gain from owning our common units.

Non-U.S. persons are generally taxed and subject to U.S. federal income tax filing requirements on income effectively connected with a U.S. trade or business. Income allocated to our unitholders and any gain from the sale of our units will generally be considered to be "effectively connected" with a U.S. trade or business. As a result, distributions to a non-U.S. unitholder will be subject to withholding at the highest applicable effective tax rate and a non-U.S. unitholder who sells or otherwise disposes of a common unit will also be subject to U.S. federal income tax on the gain realized from the sale or disposition of that unit.

The Internal Revenue Code also imposes a U.S. federal income tax withholding obligation of 10% of the amount realized upon a non-U.S. person's sale or exchange of an interest in a partnership if any portion of the gain on such transfer would be treated as effectively connected income. However, the application of this withholding requirement has been suspended for dispositions of publicly traded partnership interests, including transfers of our common units, that occur before January 1, 2022. For transfers of common units occurring after December 31, 2021, the amount realized on a transfer of common units will generally be the amount of gross proceeds paid to the broker effecting the applicable transfer on behalf of the transferor, and the broker will generally be responsible for the relevant withholding obligations. Non-U.S. unitholders should consult their tax advisors regarding the impact of these rules on an investment in our common units.

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

Because we cannot match transferors and transferees of common units, we have adopted depletion, depreciation and amortization positions that may not conform with all aspects of existing U.S. 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 on the sale of common units and could have a negative impact on the value of our common units or result in audits of and adjustments to our unitholders' tax returns.

We prorate our items of income, gain, loss and deduction between transferors and transferees of common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common 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 between transferors and transferees of common units each month based upon the ownership of our common units on the first day of each month, instead of on the basis of the date a particular common unit is transferred. Although Treasury regulations allow publicly traded partnerships to use a similar monthly simplifying convention, these regulations do not specifically authorize all aspects of our proration method. If the IRS were to successfully challenge our proration method, we may be required to change the allocation of items of income, gain, loss and deduction among our unitholders.

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

Because a unitholder whose common units are loaned to a "short seller" to cover a short sale of common units may be considered as having disposed of the loaned common units, the unitholder may no longer be treated for U.S. federal income tax purposes as a partner with respect to those common 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 common units may not be reportable by the unitholder and any distributions received by the unitholder as to those common units could be fully taxable as ordinary income. 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 with their tax advisor about whether it is advisable to modify any applicable brokerage account agreements to prohibit their brokers from loaning their common units.

We have adopted certain valuation methodologies in determining a unitholder's allocations of income, gain, loss and deduction. The IRS may challenge these methodologies or the resulting allocations, and such a challenge could adversely affect the value of our common units.

In determining the items of income, gain, loss and deduction allocable to our unitholders, we routinely 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 ourselves using a methodology based on the market value of our common units as a means to determine 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 timing, character or amount of taxable income or loss being allocated to our unitholders. It also could affect the amount of gain from our unitholders' sale of common units and could have a negative impact on the value of our common units or result in audit adjustments to our unitholders' tax returns without the benefit of additional deductions.

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

In addition to U.S. federal income taxes, our unitholders will likely be subject to other taxes, including state and local income taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which we do business or own property now or in the future, even if they do not reside 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. Furthermore, our unitholders may be subject to penalties for failure to comply with those requirements. It is the responsibility of each unitholder to file all U.S. federal, state and local tax returns that may be required of such unitholder.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A description of our properties is included in "Part I, Item 1. Business," and is incorporated herein by reference.

The obligations under our Credit Agreement are secured by mortgages on substantially all of our assets. See "Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreement," in this Form 10-K for additional information concerning our Credit Agreement.

Item 3. Legal Proceedings

From time to time we may be the subject of lawsuits and claims arising in the ordinary course of business. Management cannot predict the ultimate outcome of such lawsuits or claims. Management does not currently expect the outcome of any of the known claims or proceedings to individually or in the aggregate have a material adverse effect on our results of operations or financial condition.

To date, no claims relating to the Mesquite Chapter 11 Case have been filed against us. However, on March 13, 2020, the official committee of unsecured creditors in the Mesquite Chapter 11 Case (the "Committee") filed the *Motion of the Official Committee of Unsecured Creditors for Leave, Standing, and Authority to Prosecute Claims on Behalf of the Debtors' Estate and for Related Relief* (the "Standing Motion"). In its Standing Motion, the Committee sought, in relevant part, authority from the Court to prosecute certain identified claims against the Partnership, the general partner and Catarina Midstream, LLC (collectively, the "Evolve Parties" and the claims, the "Claims") that, if valid, belong to Mesquite.

On June 30, 2020, the SN Debtors emerged from the Mesquite Chapter 11 Case, with Mesquite becoming a privately held corporation. Upon emergence, the Claims re-vested, and are owned by, the Reorganized Debtors (as defined in the Plan). Accordingly, the Committee was dissolved and no longer retains the authority to bring all or a portion of the Claims against the Evolve Parties. Further, the Settlement Agreement contemplates, in relevant part, the settlement of the Claims between the Reorganized Debtors and the Evolve Parties. However, the Rejection Lawsuits were not resolved as of October 1, 2020, and as a result the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms. To date, none of the parties to the Settlement Agreement have provided notice of termination. The settlement of the Claims in accordance with the terms of the Settlement Agreement may be adversely impacted if the Bankruptcy Court does not rule in favor of the SN Debtors in the Rejection Lawsuits.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Our common units are listed on the NYSE American under the symbol "SNMP."

Holders

The number of unitholders of record of our common units was approximately 44 on March 16, 2021, which does not include beneficial owners whose shares are held by a clearing agency, such as a broker or a bank.

Distributions

Rationale for Our Cash Distribution Policy

Our partnership agreement requires us to distribute all of our available cash quarterly. Our cash distribution policy reflects a fundamental judgment that our unitholders generally will be better served by our distributing rather than retaining our available cash. However, other than the requirement in our partnership agreement to distribute all of our available cash each quarter, we have no legal obligation to make quarterly cash distributions in any amount, and our general partner has considerable discretion to determine the amount of our available cash each quarter. Our partnership agreement generally defines "available cash" as cash on hand at the end of a quarter after the payment of expenses, less the amount of cash reserves established by our general partner to provide for the conduct of our business and to comply with applicable law, any of our debt instruments or other agreements or to provide for future distributions to our unitholders for any one or more of the next four quarters. Our available cash may also include, if our general partner so determines, all or any portion of the cash on hand immediately prior to the date of distribution of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter. Because we are not subject to an entity-level federal income tax, we expect to have more cash to distribute to our unitholders than would be the case if we were subject to entity-level federal income tax. If we do not generate sufficient available cash from our operations, we may, but are under no obligation to, borrow funds to pay distributions to our unitholders.

Limitations on Cash Distributions and Our Ability to Change Our Cash Distribution Policy

There is no guarantee that we will make quarterly cash distributions to our unitholders. We do not have a legal or contractual obligation to pay quarterly distributions or any other distributions except as provided in our partnership agreement. Our cash distribution policy may be changed at any time and is subject to certain restrictions and uncertainties, including the following:

- Until the first quarter in which no Class C Preferred Units remain outstanding, we are not permitted to declare or make any distributions in respect to our common units.

- Our cash distribution policy is subject to restrictions on distributions under our Credit Agreement, which contains financial tests that we must meet and covenants that we must satisfy. Should we be unable to meet these financial tests or satisfy these covenants or if we are otherwise in default under our Credit Agreement, we will be prohibited from making cash distributions notwithstanding our 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 of or increase in those reserves could result in a reduction in cash distributions from levels we currently anticipate pursuant to our stated cash distribution policy. Our partnership agreement does not set a limit on the amount of cash reserves that our general partner may establish. Any decision to establish cash reserves made by our general partner in good faith will be binding on our unitholders.

- Prior to making any distribution on our common units, and pursuant to the Shared Services Agreement, we will pay SP Holdings an administrative fee and reimburse our general partner and its affiliates, including SP Holdings, for all direct and indirect expenses that they incur on our behalf. Neither our partnership agreement nor the Shared Services Agreement limits the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses may include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our partnership agreement provides that our general partner will determine in good faith the expenses that are allocable to us. The reimbursement of expenses and payment of fees, if any, to our general partner and its affiliates may impact our ability to pay distributions to our unitholders.

- While our partnership agreement requires us to distribute all of our available cash, our partnership agreement, including the provisions requiring us to make cash distributions contained therein, may be amended with the consent of our general partner and the approval of a majority of the outstanding common units (including common units held by Mesquite and its affiliates, if any).

- Even if our cash distribution policy is not modified or revoked, the decisions regarding the amount of distributions to pay under our cash distribution policy and whether to pay any distribution are determined by our general partner, taking into consideration the terms of our partnership agreement.

- Under Section 17-607 of the Delaware Act, 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 a shortfall in cash flows 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 outstanding debt, tax expenses, working capital requirements or anticipated cash needs.

- If we make distributions out of capital surplus, as opposed to operating surplus, any such distributions would constitute a return of capital and would result in a reduction in the minimum quarterly distribution and the target distribution levels. We do not anticipate that we will make any distributions from capital surplus.

- Our ability to make distributions to our unitholders depends on the performance of our assets and subsidiaries and the ability of our subsidiaries to distribute cash to us. The ability of our subsidiaries to make distributions to us may be restricted by, among other things, the provisions of future indebtedness, applicable state laws and other laws and regulations.

General Partner Interest

Our general partner owns a non-economic general partner interest in us, which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

Incentive Distribution Rights

All of the incentive distribution rights are held by SP Holdings. Incentive distribution rights represent the right to receive increasing percentages (13%, 23% and 35.5%) of quarterly distributions from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved.

For any quarter in which we have distributed cash from operating surplus to our common unitholders in an amount equal to the minimum distribution and distributed cash from surplus to the outstanding common units to eliminate any cumulative arrearages in payment of the minimum quarterly distribution, then we will distribute any additional cash from operating surplus for that quarter among the unitholders and the incentive distribution rights holders in the following manner:

	Total Quarterly Distribution Per Common Unit	Marginal Percentage Interest in Distributions	
		Common Unitholders	SP Holdings (as Holder of Incentive Distribution Rights)
Minimum Quarterly Distribution	up to $0.50	100.00%	0.00%
First Target Distribution	above $0.50 up to $0.575	100.00%	0.00%
Second Target Distribution	above $0.575 up to $0.625	87.00%	13.00%
Third Target Distribution	above $0.625 up to $0.875	77.00%	23.00%
Thereafter	above $0.875	64.50%	35.50%

Securities Authorized for Issuance Under Equity Compensation Plans

See “Part III, Item 12. Security Ownership of Certain Benefits Owners and Management and Related Unitholder Matters” for information regarding our equity compensation plan as of December 31, 2020.

Recent Sales of Unregistered Securities

No unregistered common units were sold by us during the fourth-quarter 2020.

Purchases of Equity Securities by Us and our Affiliates

No common units were repurchased by us during the fourth-quarter 2020.

Default Upon Senior Securities

There were no defaults on senior securities for the years ended December 31, 2020 or 2019.

Item 6. Selected Financial Data

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information required by this Item.

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

The following discussion and analysis should be read in conjunction with the financial statements and the summary of significant accounting policies and notes included herein this Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, forecasts, guidance, beliefs and expected performance. The "forward-looking statements" are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these "forward-looking statements". Please read "Cautionary Note Regarding Forward-Looking Statements."

Overview

We are a publicly-traded limited partnership formed in 2005 focused on the acquisition, development and ownership of infrastructure critical to the transition of energy supply to lower carbon sources. We own natural gas gathering systems, pipelines, and processing facilities in South Texas and continue to pursue energy transition infrastructure opportunities. Our common units are currently listed on the NYSE American under the symbol "SNMP."

On February 26, 2021, in connection with our management team's focus on expanding our business strategy to focus on the ongoing energy transition in the industries in which we operate, we changed our name to Evolve Transition Infrastructure LP and our general partner changed its name to Evolve Transition Infrastructure GP LLC.

COVID-19

In March 2020, the World Health Organization declared COVID-19 a pandemic and recommended containment and mitigation measures worldwide and the United States declared a national emergency with respect to COVID-19. As a result, extraordinary and wide-ranging actions were taken by international, federal, state and local public health and governmental authorities to reduce the spread of COVID-19, including quarantines, government restrictions on movement, business closures and suspensions, canceled events and activities, self-isolation, and other voluntary or mandated changes in behavior. Such actions have also resulted in significant business and operational disruptions, including supply chain disruptions, travel restrictions, stay-at-home orders and limitations on the availability of workforces. COVID-19 and the ongoing response to mitigate its impact have contributed to a massive economic shutdown and decreased demand for crude oil and natural gas.

Also in the first quarter of 2020, Saudi Arabia and Russia increased production of crude oil as the two countries competed for market share. As a result, the global supply of crude oil significantly exceeded demand and led to a collapse in crude oil prices. The collapse in crude oil prices and the related impact on crude oil drilling resulted in crude oil, natural gas and NGL production being curtailed in the second quarter of 2020.

While crude oil prices have started to rebound from the lows reached during the early stages of the COVID-19 pandemic, the volatility in oil prices and impact of the Mesquite Chapter 11 Case have caused a negative impact on our net cash flows during the year ended December 31, 2020. If Mesquite should decide to shut-in any of the wells connected to our midstream facilities or otherwise becomes unable to make future payments under the Gathering Agreement, it could have a material and adverse impact on our business. The full extent to which the COVID-19 pandemic impacts our business and operations will depend on the severity, location and duration of the effects and spread of COVID-19, the actions undertaken by national, regional and local governments and health officials to contain the virus or treat its effects, and how quickly and to what extent economic conditions improve and normal business and operating conditions resume. Please read "Part I, Item 1A. Risk Factors."

Mesquite Bankruptcy – Settlement Agreement and Rejection Lawsuits

On August 11, 2019, the SN Debtors filed the Mesquite Chapter 11 Case in the Bankruptcy Court.

On June 6, 2020, the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, including but not limited to, (i) Amendment No. 2, (ii) the Seco Catarina Agreement, and (iii) that the Seco Comanche Agreement. Each such agreement will become effective only upon satisfaction of certain closing conditions described in the Settlement Agreement.

On June 23, 2020, certain affiliates of each Occidental Petroleum Corp., The Blackstone Group and GSO Capital Partners each filed a complaint (collectively, the “Rejection Lawsuits”) against Mesquite and certain of its subsidiaries requesting, among other things, that the Bankruptcy Court not approve the rejection of certain commercial agreements, as set forth in the Settlement Agreement, in connection with Mesquite’s Comanche Asset.

On June 30, 2020, the SN Debtors emerged from the Mesquite Chapter 11 Case, with Mesquite becoming a privately held corporation.

The commercial agreements contemplated by the Settlement Agreement will not become effective until, among other things, the Rejection Lawsuits have been resolved in favor of the SN Debtors and the Bankruptcy Court has approved the rejection of the certain commercial agreements underlying the Rejection Lawsuits. The Rejection Lawsuits were not resolved by October 1, 2020, and as a result the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms. To date, none of the parties of the Settlement Agreement have provided notice of termination.

Stonepeak Transactions

On September 7, 2020, SP Capital Holdings, LLC (“SP Capital”), SP Common Equity LLC (“SPCE”), and Stonepeak Catarina, entered into a Contribution and Exchange Agreement (the “Contribution Agreement”), pursuant to which (i) SP Capital contributed 100% of the issued and outstanding membership interest in SP Holdings to Stonepeak Catarina, (ii) SPCE irrevocably committed to contribute 100 % of the issued and outstanding membership interests in SP Common Equity Subsidiary LLC (“SPCE Sub”) to Stonepeak Catarina, and (iii) as consideration for the contributions, Stonepeak Catarina issued 10,000 Class B Units in Stonepeak Catarina to SP Capital and 5,000 Class C Units in Stonepeak Catarina to SPCE. Such transactions were completed in their entirety on October 5, 2020. As a result of these transactions, Stonepeak gained control of our general partner and SP Holdings.

Pursuant to our partnership agreement, the general partner conducts, directs and manages all activities of the Partnership under the authority of the Board. Pursuant to the Limited Liability Company Agreement of our general partner, dated March 2, 2015, as amended, SP Holdings appoints all of the members of the Board, other than two directors which Stonepeak is entitled to designate pursuant to the Representation and Standstill Agreement.

On October 6, 2020, Amendment No. 8 to Schedule 13D (the “Catarina 13D”) was filed on behalf of each of (i) SPCE Sub, (ii) Stonepeak Catarina, (iii) Stonepeak Catarina Upper Holdings LLC, (iv) Stonepeak Infrastructure Fund (Orion AIV) LP, (v) Stonepeak Associates LLC, (vi) Stonepeak GP Holdings LP, (vii) Stonepeak GP Investors LLC, (viii) Stonepeak GP Investors Manager LLC, (ix) Michael Dorrell, and (x) Trent Vichie, in it was disclosed that SP Holdings began engaging in non-binding discussions with the Board about terminating or, alternatively, amending and restating the Shared Services Agreement. The Shared Services Agreement can be terminated (i) by either party at any time by 180 days’ prior written notice to the other party, (ii) by SP Holdings if there is an uncured material breach thereunder by the Partnership, or (iii) by the Partnership, subject to Board approval, if (1) there is an uncured material breach thereunder by SP Holdings or (2) there is a change in control of SP Holdings. Pursuant to the Standstill Agreement, the Partnership must obtain Stonepeak Catarina’s consent to its termination of the Shared Services Agreement. The Shared Services Agreement provides that if there is a termination other than by either party at the end of the Service Agreement’s term, by the Partnership for an uncured breach by SP Holdings, or by the Partnership upon a change of control of SP Holdings, then the Partnership will owe a termination payment to SP Holdings in an amount equal to $5,000,000 plus 5% of the transaction value of all asset acquisitions theretofore consummated. We estimate that this amount was in excess of $35.0 million as of December 31, 2020. Such termination fee may be payable in cash or common units. If the Partnership terminates upon 180 days’ prior notice then the Partnership must also pay to SP Holdings all costs and expenses of SP Holdings that result from such termination. The Catarina 13D reports that SP Holdings may terminate the Shared Services Agreement upon 180 days’ prior written notice to the Partnership and such termination would trigger the Partnership’s obligation to pay the termination fee in an amount equal to $5,000,000 plus 5% of the transaction value of all asset acquisitions theretofore consummated. To date, no notice of termination of the Shared Services Agreement has been delivered by SP Holdings.

On November 11, 2020, the Board declared that after establishing a cash reserve for the payment of certain amounts outstanding under the Credit Agreement, the Partnership did not have any available cash and, as a result, there would be no cash distribution on the Partnership’s common units. Section 5.9(b)(ii) of the Amended Partnership Agreement requires that the quarterly distribution on the Class C Preferred Units be paid in cash, Class C Preferred PIK Units or a combination thereof. On November 16, 2020, the Partnership and Stonepeak Catarina entered into a letter agreement (the "Stonepeak Letter Agreement") wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The Stonepeak Letter Agreement also provides that Stonepeak Catarina will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the end of such quarter. The Stonepeak Letter Agreement and the transactions completed therein, including the distribution for the three months ended September 30, 2020 (the "Letter Agreement Transactions"), was referred to the Conflicts Committee of the Board. The Conflicts Committee approved the Letter Agreement Transactions, recommended that the Board approve and authorize the execution and performance of the Letter Agreement Transactions, and verified that their approvals constituted "Special Approval" of the Letter Agreement Transactions under and pursuant to our partnership agreement. Following the approval and recommendation from the Conflicts Committee, the Board approved the Letter Agreement Transactions. The aggregate distribution of 22,274,869 common units was made to Stonepeak Catarina on February 1, 2021, following the satisfaction of certain issuance conditions, including, among other things, the delivery by the Partnership of a fully executed supplemental listing application from the NYSE American approving the issuance of the Stonepeak Common Distribution Units and the compliance by the Partnership and Stonepeak Catarina with any applicable federal securities laws applicable to the issuance of the Stonepeak Common Distribution Units.

On January 28, 2021, Stonepeak Catarina provided us with its notice of election to receive a Common Unit PIK Distribution for the fourth quarter of 2020. The aggregate distribution of 12,445,491 common units was made to Stonepeak Catarina on February 25, 2021, following the satisfaction of certain issuance conditions.

We refer to the foregoing transactions collectively as the "Stonepeak Transactions."

As a result of the Stonepeak Transactions, as of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) the Warrant that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights.

Pursuant to Section 15.1 of our partnership agreement, if at any time Stonepeak holds more than 80% of our outstanding common units and completes the Stonepeak LCR Transfer, Stonepeak will be able to cause our general partner or a controlled affiliate of our general partner to exercise its right to acquire all, but not less than all, of our common units held by persons other than our general partner and its controlled affiliates (the "limited call right"). Stonepeak would effect any such exercise by first transferring all of the common units held by it to our general partner or a controlled affiliate of our general partner (the "Stonepeak LCR Transfer") and then causing our general partner to exercise its limited call right at a price equal to the greater of (1) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the limited call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its controlled affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Common unitholders may also incur tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of common units to be repurchased upon exercise of the limited call right. Furthermore, there is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units, including common units issued pursuant to the Stonepeak Letter Agreement or as a result of the termination or renegotiation of the Shared Services Agreement, and then exercising its limited call right. If our general partner exercises its limited call right, the effect would be to take the Partnership private and, if the common units are subsequently deregistered, the Partnership will no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended. As of March 16, 2021, the General Partner and its controlled affiliates do not own any Common Units.

Our Relationship with Stonepeak

We have had a relationship with Stonepeak since 2015. Stonepeak has a significant ownership interest in us and our affiliates, including our general partner and SP Holdings, controls us and our general partner and has the ability to appoint all of the members of the Board.

Stonepeak Catarina is indirectly managed by Stonepeak Partners LP, a leading North American infrastructure private equity firm ("Stonepeak Partners"). Stonepeak Partners' significant infrastructure and midstream energy expertise and deep financial resources are reflected in over $31 billion of assets under management, with to date including, among others, preferred and common interests in the Partnership, MPLX LP, Phillips 66 Partners LP, Plains All American Pipeline, L.P. and Targa Resources Corp. We believe that, as a result of Stonepeak's significant ownership interest in us, Stonepeak is incentivized to support and promote our business plan and to encourage us to pursue projects that enhance the overall value of our business. While our relationship with Stonepeak is a significant strength, it is also a source of potential risks and conflicts. Please read "Part I, Item 1A. Risk Factors—Risks Inherent in an Investment in Our Common Units" and "Part III, Item 13. Certain Relationships and Related Transactions, and Director Independence."

Business Strategy

Our primary business objective is to create long-term value by generating stable and predictable cash flows that allow us to reduce the amount of our indebtedness and pursue energy transition infrastructure opportunities. We plan to achieve this objective by executing the following business strategy:

- grow our business through the acquisition and development of infrastructure critical to the transition of energy supply to lower carbon sources;
- pursue organic investments in our existing operating areas to support growth;
- pursue strategic relationships with third-party producers and other companies with operations in the area in which we operate in order to maximize the utilization of our midstream facilities or provide other revenue-generating services; and
- maintain financial flexibility and a strong capital structure.

Business Segments

Our business activities are conducted under two operating segments for which we provide information in our consolidated financial statements for the years ended December 31, 2020 and 2019. These two segments are based on the nature of the operations that are undertaken by each segment and are our:

- midstream business, which includes Western Catarina Midstream, the Carnero JV and Seco Pipeline (each as defined below); and
- production business, which includes non-operated oil and natural gas interests located in the Eagle Ford Shale in South Texas and in other areas of Texas and Louisiana.

For information about our segments' revenues, profits and losses and total assets, see Note 17 "Reporting Segments" of our Notes to Consolidated Financial Statements.

Significant Operational Factors in 2020

Some key highlights of our business activities for the year ended December 31, 2020 were:

- On Western Catarina Midstream, the Partnership continued the implementation of two tariff rate increases on throughput volumes from the portion of Mesquite's Catarina Asset which is not currently dedicated under the Gathering Agreement; and

- For the year ended December 31, 2020, we reduced cash related general and administrative expense by $1.6 million, or 16%, compared to the same period in 2019.

How We Evaluate Our Operations

We evaluate our business on the basis of the following key measures:

- our throughput volumes on gathering systems upon those assets;
- our operating expenses; and
- our Adjusted EBITDA, a non-GAAP financial measure (for a reconciliation of Adjusted EBITDA to the most comparable GAAP financial measure please read "Non-GAAP Financial Measures—Adjusted EBITDA").

Throughput Volumes

Our management analyzes our performance based on the aggregate amount of throughput volumes on the gathering system. We must connect additional wells or well pads within Mesquite's Catarina Asset, which is in Dimmit, La Salle and Webb counties in Texas, in order to maintain or increase throughput volumes on Western Catarina Midstream. Our success in connecting additional wells is impacted by successful drilling activity by Mesquite on the acreage dedicated to Western Catarina Midstream, our ability to secure volumes from Mesquite or third parties from new wells drilled on non-dedicated acreage, our ability to attract hydrocarbon volumes currently gathered by our competitors and our ability to cost-effectively construct or acquire new infrastructure. Construction of the Seco Pipeline was completed in August 2017, however, Mesquite does not currently transport any volumes on the Seco Pipeline following termination of the Seco Pipeline Transportation Agreement effective February 12, 2020. Future throughput volumes on the pipeline are dependent on execution of a new transportation agreement with Mesquite or execution of an agreement with a third party.

Operating Expenses

Our management seeks to maximize Adjusted EBITDA, a non-GAAP financial measure, in part by minimizing operating expenses. These expenses are, or will be, comprised primarily of field operating costs (which generally consists of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, among other items), compression expense, ad valorem taxes and other operating costs, some of which will be independent of our oil and natural gas production or the throughput volumes on the midstream gathering system, but fluctuate depending on the scale of our operations during a specific period.

Non-GAAP Financial Measures—Adjusted EBITDA

To supplement our financial results and guidance presented in accordance with U.S. generally accepted accounting principles ("GAAP"), we use Adjusted EBITDA, a non-GAAP financial measure, in this Form 10-K. We believe that non-GAAP financial measures are helpful in understanding our past financial performance and potential future results, particularly in light of the effect of various transactions effected by us. We define Adjusted EBITDA as net income (loss) adjusted by: (i) interest (income) expense, net, which includes interest expense, interest expense net (gain) loss on interest rate derivative contracts, and interest (income); (ii) income tax expense (benefit); (iii) depreciation, depletion and amortization; (iv) asset impairments; (v) accretion expense; (vi) (gain) loss on sale of assets; (vii) unit-based compensation expense; (viii) unit-based asset management fees; (ix) distributions in excess of equity earnings; (x) (gain) loss on mark-to-market activities; (xi) commodity derivatives settled early; (xii) (gain) loss on embedded derivatives; and (xiii) acquisition and divestiture costs.

Adjusted EBITDA is used as a quantitative standard by our management and by external users of our financial statements such as investors, research analysts, our lenders and others to assess: (i) the financial performance of our assets without regard to financing methods, capital structure or historical cost basis; (ii) the ability of our assets to generate cash sufficient to pay interest costs and support our indebtedness; and (iii) our operating performance and return on capital as compared to those of other companies in our industry, without regard to financing or capital structure.

We believe that the presentation of Adjusted EBITDA provides useful information to investors in assessing our financial condition and results of operations. The GAAP measure most directly comparable to Adjusted EBITDA is net income (loss). Our non-GAAP financial measure of Adjusted EBITDA should not be considered as an alternative to GAAP net income (loss). Adjusted EBITDA has important limitations as an analytical tool because it excludes some but not all items that affect net income (loss). Adjusted EBITDA should not be considered in isolation or as a substitute for analysis of our results as reported under GAAP. Because Adjusted EBITDA may be defined differently by other companies in our industry, our definition of Adjusted EBITDA may not be comparable to similarly titled measures of other companies, thereby diminishing its utility.

The following table sets forth a reconciliation of Adjusted EBITDA to net income (loss), its most directly comparable GAAP performance measure, for each of the periods presented (in thousands):

	Years Ended December 31,	
	2020	**2019**
Net loss	$ (118,761)	$ (51,142)
Adjusted by:		
Interest expense, net	95,871	39,789
Income tax expense	24	202
Depreciation, depletion and amortization	22,873	25,333
Asset impairments	24,222	32,119
Accretion expense	567	526
Unit-based compensation expense	2,602	1,351
Unit-based asset management fees	7,245	7,321
Distributions in excess of equity earnings	11,737	11,352
(Gain) loss on mark-to-market activities	(759)	(1,183)
Adjusted EBITDA	$ 45,621	$ 65,668

Significant Operational Factors

Throughput. The following table sets forth selected throughput data pertaining to the Midstream segment for the years ended December 31, 2020 and 2019:

	Years Ended December 31,	
	2020	**2019**
Western Catarina Midstream:		
Oil (MBbls/d)	7.4	11.1
Natural gas (MMcf/d)	93.6	131.7
Water (MBbls/d)	3.1	5.5
Seco Pipeline:		
Natural gas (MMcf/d)	—	1.9

Production. Our production for the year ended December 31, 2020 was approximately 241 MBoe, or an average of 658 Boe/d, compared to approximately 309 MBoe, or an average of 847 Boe/d, for the same period in 2019.

Capital Expenditures. For the year ended December 31, 2020, we spent approximately $1.9 million in capital expenditures, of which $1.7 million related to the development of the Seco Pipeline. For the year ended December 31, 2019, we spent approximately $0.5 million in capital expenditures, consisting of $0.5 million related to the development of Western Catarina Midstream and less than $0.1 million related to the development of the Seco Pipeline.

Hedging Activities. For the year ended December 31, 2020, the non-cash mark-to-market loss for our commodity derivatives was approximately $0.8 million, compared to a loss of approximately $4.7 million for the same period in 2019.

Results of Operations by Segment

Midstream Operating Results

The following table sets forth the selected financial and operating data pertaining to the Midstream segment for the periods indicated (in thousands):

	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance	
Revenues:				
Gathering and transportation sales	$ 785	$ 6,825	$ (6,040)	(88)%
Gathering and transportation lease revenues	44,671	59,090	(14,419)	(24)%
Total gathering and transportation sales	45,456	65,915	(20,459)	(31)%
Operating costs:				
Lease operating expenses	884	1,499	(615)	(41)%
Transportation operating expenses	9,314	11,553	(2,239)	(19)%
Depreciation and amortization	20,655	21,391	(736)	(3)%
Asset impairments	867	32,119	(31,252)	(97)%
Accretion expense	355	326	29	9%
Total operating expenses	32,075	66,888	(34,813)	(52)%
Other income:				
Earnings from equity investments	4,479	2,831	1,648	58%
Operating income	$ 17,860	$ 1,858	$ 16,002	861%

Gathering and transportation sales. Gathering and transportation sales decreased by approximately $6.0 million, or 88%, to approximately $0.8 million for the year ended December 31, 2020, compared to approximately $6.8 million during the same period in 2019. This decrease was due to the termination of the Seco Pipeline Transportation Agreement effective February 12, 2020.

Gathering and transportation lease revenues. Gathering and transportation lease revenues decreased by approximately $14.4 million, or 24%, to approximately $44.7 million for the year ended December 31, 2020, compared to approximately $59.1 million during the same period in 2019. This decrease was primarily the result of a decrease in the natural gas transported on Western Catarina Midstream.

Lease operating expenses. Lease operating expenses, which include ad valorem taxes, decreased approximately $0.6 million, or 41%, to approximately $0.9 million for the year ended December 31, 2020, compared to approximately $1.5 million during the same period in 2019. This decrease was primarily attributable to a decrease in throughput volumes between the comparative periods.

Transportation operating expenses. Our transportation operating expenses generally consist of gathering and transportation operating expenses, labor, vehicles, supervision, minor maintenance, tools, supplies, and integrity management expenses. Our transportation operating expense decreased approximately $2.2 million, or 19%, to approximately $9.3 million for the year ended December 31, 2020, compared to approximately $11.6 million during the same period in 2019. The decrease in transportation operating expenses was due to a decrease in throughput volumes between the comparative periods.

Depreciation and amortization expense. Gathering and transportation assets are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 5 to 15 years for equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets. Our depreciation and amortization expense decreased approximately $0.7 million, or 3%, to approximately $20.7 million for the year ended December 31, 2020, compared to approximately $21.4 million during the same period in 2019. This decrease was due to the impairment of the Seco Pipeline as of December 31, 2019 to a fair value of zero. As a result of this impairment, there was no depreciation recorded on the Seco Pipeline during the year ended December 31, 2020.

Impairment expense. For the year ended December 31, 2020, our non-cash impairment charge to impair the Seco Pipeline was approximately $0.9 million. During 2020 we made an agreed upon cash settlement related to the original construction of the Seco Pipeline which was impaired to a fair value of zero. For the year ended December 31, 2019, our non-cash impairment charge to impair the Seco Pipeline was approximately $32.1 million. We received a written notice from Mesquite terminating the Seco Pipeline Transportation Agreement effective as of February 12, 2020.

Earnings from equity investments. Earnings from equity investments increased approximately $1.6 million, or 58%, to earnings of approximately $4.5 million for the year ended December 31, 2020, compared to earnings of approximately $2.8 million for the same period in 2019. This increase in earnings was primarily the result of a reduction in operating expenses at one of the natural gas processing facilities during the year ended December 31, 2020.

Production Operating Results

The following tables set forth the selected financial and operating data pertaining to the Production segment for the periods indicated (in thousands, except net production and average sales and costs):

	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance	
Revenues:				
Natural gas sales at market price	$ 340	$ 424	$ (84)	(20)%
Natural gas hedge settlements	313	94	219	NM [(a)]
Natural gas mark-to-market activities	(226)	165	(391)	NM [(a)]
Natural gas total	427	683	(256)	(37)%
Oil sales	7,042	13,543	(6,501)	(48)%
Oil hedge settlements	2,829	807	2,022	NM [(a)]
Oil mark-to-market activities	985	(4,838)	5,823	NM [(a)]
Oil total	10,856	9,512	1,344	14%
NGL sales	254	539	(285)	(53)%
Total revenues	11,537	10,734	803	7%
Operating costs:				
Lease operating expenses	5,340	5,879	(539)	(9)%
Production taxes	311	621	(310)	(50)%
Depreciation, depletion and amortization	2,218	3,942	(1,724)	(44)%
Asset impairments	23,355	—	23,355	NM [(a)]
Accretion expense	212	200	12	6%
Total operating expenses	31,436	10,642	20,794	NM [(a)]
Operating income (loss)	$ (19,899)	$ 92	$ (19,991)	NM [(a)]

(a) Variances deemed to be Not Meaningful "NM."

	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance	
Net production:				
Natural gas (MMcf)	158	231	(73)	(32)%
Oil production (MBbl)	191	228	(37)	(16)%
NGLs (MBbl)	24	42	(18)	(43)%
Total production (MBoe)	241	309	(68)	(22)%
Average daily production (Boe/d)	658	847	(189)	(22)%
Average sales prices:				
Natural gas price per Mcf with hedge settlements	$ 4.13	$ 2.24	$ 1.89	84%
Natural gas price per Mcf without hedge settlements	$ 2.15	$ 1.84	$ 0.32	17%
Oil price per Bbl with hedge settlements	$ 51.68	$ 62.94	$ (11.26)	(18)%
Oil price per Bbl without hedge settlements	$ 36.87	$ 59.40	$ (22.53)	(38)%
NGL price per Bbl without hedge settlements	$ 10.58	$ 12.83	$ (2.25)	(18)%
Total price per Boe with hedge settlements	$ 44.72	$ 49.86	$ (5.14)	(10)%
Total price per Boe without hedge settlements	$ 31.68	$ 46.94	$ (15.26)	(33)%
Average unit costs per Boe:				
Field operating expenses [(a)]	$ 23.45	$ 21.04	$ 2.41	11%
Lease operating expenses	$ 22.16	$ 19.03	$ 3.13	16%
Production taxes	$ 1.29	$ 2.01	$ (0.72)	(36)%
Depreciation, depletion and amortization	$ 9.20	$ 12.76	$ (3.55)	(28)%

(a) Field operating expenses include lease operating expenses (average production costs) and production taxes.

Production, For the year ended December 31, 2020, 79% of our production was oil, 10% was NGLs and 11% was natural gas compared to the year ended December 31, 2019, where 74% of our production was oil, 14% was NGLs and 12% was natural gas.

Sales of natural gas, NGLs and oil. Unhedged oil sales decreased $6.5 million, or 48%, to $7.0 million for the year ended December 31, 2020, compared to approximately $13.5 million for the same period in 2019. Sales of NGLs decreased approximately $0.3 million, or 53%, to $0.3 million for the year ended December 31, 2020, compared to approximately $0.5 million for the same period in 2019. Unhedged natural gas sales decreased approximately $0.1 million, or 20%, to approximately $0.3 million for the year ended December 31, 2020, compared to approximately $0.4 million for the same period in 2019. The total decrease in sales of natural gas, NGLs and oil for the year ended December 31, 2020 was primarily the result of a decrease in average sales prices.

Including hedges and mark-to-market activities, our total production-related revenue increased approximately $0.8 million for the year ended December 31, 2020. This increase was primarily the result of a reduction in oil sales of approximately $6.5 million offset by an increase in hedge and mark-to-market gains of approximately $7.8 million.

The following tables provide an analysis of the impacts of changes in production volumes and average realized prices between the periods on our unhedged revenues for the year ended December 31, 2020 compared to the year ended December 31, 2019 (in thousands, except average sales prices and volumes):

	2020 Average Sales Price	2019 Average Sales Price	Difference	2020 Volume	Revenue Decrease due to Price
Natural gas (MMcf)	$ 2.15	$ 1.84	$ 0.32	158	$ 51
Oil (MBbl)	$ 36.87	$ 59.40	$ (22.53)	191	$ (4,303)
NGLs (MBbl)	$ 10.58	$ 12.83	$ (2.25)	24	$ (54)
Total oil equivalent (MBoe)	$ 31.68	$ 46.94	$ (15.26)	241	$ (4,306)

	2020 Production Volume	2019 Production Volume	Difference	2019 Average Sales Price	Revenue Decrease due to Production
Natural gas (MMcf)	158	231	(73)	$ 1.84	$ (134)
Oil (MBbl)	191	228	(37)	$ 59.40	$ (2,198)
NGLs (MBbl)	24	42	(18)	$ 12.83	$ (231)
Total oil equivalent (MBoe)	241	309	(68)	$ 46.94	$ (2,563)

A 10% increase or decrease in our average realized sales prices, excluding the impact of derivatives, would have increased or decreased our revenues for the year ended December 31, 2020 by approximately $0.8 million.

Hedging and mark-to-market activities. We apply mark-to-market accounting to our derivative contracts; therefore, the full volatility of the non-cash change in fair value of our outstanding contracts is reflected in oil and natural gas revenues. For the year ended December 31, 2020, the non-cash mark-to-market gains were approximately $0.8 million, compared to losses of approximately $4.7 million for the same period in 2019. Cash settlements received for our commodity derivatives were approximately $3.1 million for the year ended December 31, 2020, compared to settlements received of approximately $0.9 million for the year ended December 31, 2019.

Field operating expenses. Our field operating expenses generally consist of lease operating expenses, labor, vehicles, supervision, transportation, minor maintenance, tools and supplies expenses, as well as production and ad valorem taxes.

Lease operating expenses. Lease operating expenses decreased approximately $0.5 million, or 9%, to approximately $5.3 million for the year ended December 31, 2020, compared to $5.9 million for the same period in 2019.

Depreciation, depletion and amortization expense. Depreciation, depletion and amortization expense includes the depreciation, depletion and amortization of acquisition costs and equipment costs. Depletion is calculated using units-of-production under the successful efforts method of accounting. Assuming other variables remain constant, as the production of natural gas, NGLs and oil increases or decreases, our depletion expense would increase or decrease as well, respectively.

Our depreciation, depletion and amortization expense for the year ended December 31, 2020 was approximately $2.2 million, compared to approximately $3.9 million for the same period in 2019. The decrease was primarily the result of asset impairments in 2020 reducing our depletion rate.

Impairment expense. For the year ended December 31, 2020, our non-cash proved property impairment charge was approximately $23.4 million. For the year ended December 31, 2019, we did not record impairment on our oil and natural gas properties.

Consolidated Earnings Results

The following table sets forth the reconciliation of segment operating income to net income (loss) for periods indicated (in thousands):

	Years Ended December 31, 2020	Years Ended December 31, 2019	Variance	
Reconciliation of segment operating income (loss) to net income (loss)				
Total production operating income (loss)	$ (19,899)	$ 92	$ (19,991)	NM [(a)]
Total midstream operating income	17,860	1,858	16,002	861%
Total segment operating income (loss)	(2,039)	1,950	(3,989)	NM [(a)]
General and administrative expenses	(18,296)	(17,610)	(686)	4%
Unit-based compensation expense	(2,602)	(1,351)	(1,251)	93%
Interest expense, net	(95,871)	(39,789)	(56,082)	141%
Other income	71	5,860	(5,789)	(99)%
Income tax benefit (expense)	(24)	(202)	178	(88)%
Net loss	$ (118,761)	$ (51,142)	$ (67,619)	132%

(a) Variances deemed to be Not Meaningful "NM"

General and administrative expenses. General and administrative expenses include indirect costs billed by SP Holdings in connection with the Shared Services Agreement, field office expenses, professional fees and other costs not directly associated with field operations. General and administrative expenses increased approximately $0.7 million, or 4%, to approximately $18.3 million for the year ended December 31, 2020, compared to approximately $17.6 million for the same period in 2019. The increase was primarily the result of non-cash charges associated with the Shared Services Agreement.

Unit-based compensation expense. Unit-based compensation expense increased approximately $1.3 million, or 93%, to approximately $2.6 million for the year ended December 31, 2020, compared to approximately $1.4 million for the same period in 2019. This increase was the result of a grant in 2020 to officers of the Partnership.

Interest expense, net. Interest expense increased approximately $56.1 million, to approximately $95.9 million for the year ended December 31, 2020, compared to approximately $39.8 million for the same period in 2019. This increase was the result of the issuance of the Class C Preferred Units and the Warrant on August 2, 2019. The accrual of distributions on the Class C Preferred Units as well as the mark-to-market impact of the Warrant are charges to interest expense. Cash interest expense for the year ended December 31, 2020 was approximately $5.1 million compared to approximately $9.2 million for the same period in 2019. See Note 16. "Partner's Capital" of our Notes to Consolidated Financial Statements for additional information related to Class C Preferred Units and the Warrant.

Other income (expense). Other income for the year ended December 31, 2019 was approximately $5.9 million, resulting from changes in the fair value measurement of the earnout derivative.

Income tax expense. Income tax expense was approximately $24 thousand and $202 thousand for the years ended December 31, 2020, and 2019, respectively.

Liquidity and Capital Resources

As of December 31, 2020, we had approximately $1.7 million in cash and cash equivalents and $9.0 million available for borrowing under the Credit Agreement in effect on such date, as discussed further below. During the years ended December 31, 2020 and 2019, we paid approximately $5.2 million and $9.2 million, respectively, in cash for interest on borrowings under our Credit Agreement, of which approximately $0.1 million was related to the fee on undrawn commitments during the year ended December 31, 2020.

Our capital expenditures during the year ended December 31, 2020 were funded with cash on hand. In the future, capital and liquidity are anticipated to be provided by operating cash flows, borrowings under our Credit Agreement and proceeds from the issuance of additional common units or other limited partner interests. We expect that the combination of these capital resources will be adequate to meet our short-term working capital requirements, long-term capital expenditures program and quarterly cash distributions, if any.

We expect that our future cash requirements relating to working capital, maintenance capital expenditures and quarterly cash distributions, if any to our partners will be funded from cash flows internally generated from our operations. Our expansion capital expenditures will be funded by borrowings under our Credit Agreement or from potential capital market transactions. However, there can be no assurance that operations and other capital resources will provide cash in sufficient amounts to maintain our current debt level, planned levels of capital expenditures, operating expenses or any cash distributions that we may make to unitholders.

Credit Agreement

We have entered into the Credit Agreement with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto. The Credit Agreement provides a quarterly amortizing term loan of $155.0 million (the "Term Loan") and a maximum revolving credit amount of $17.5 million, which is reduced to the lesser of (i) $15.0 million through May 14, 2021 and (ii) from and after May 15, 2021, the positive difference of the Borrowing Base minus the aggregate outstanding principal amount of the Term Loan(the "Revolving Loan"). The Term Loan and Revolving Loan both have a maturity date of September 30, 2021. Borrowings under the Credit Agreement are secured by various mortgages of both midstream and upstream properties that we own as well as various security and pledge agreements among us, certain of our subsidiaries and the administrative agent.

Borrowings under the Credit Agreement are available for limited direct investment in oil and natural gas properties, midstream properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of up to $2.5 million which may be used for the issuance of letters of credit. Pursuant to the Credit Agreement, the initial aggregate commitment amount under the Term Loan is $155.0 million, subject to quarterly $10.0 million principal and other mandatory prepayments. The borrowing base is equal to the sum of the rolling four quarter EBITDA of our midstream operations and the amount of distributions received from the Carnero JV multiplied by 4.5 or a lower number dependent upon natural gas volumes flowing through Western Catarina Midstream. Outstanding borrowings in excess of our borrowing base must be repaid within 45 days after the first occurrence of such borrowing base deficiency, subject to certain adjustments based on previous voluntary and mandatory prepayments. As of December 31, 2020, the borrowing base under the Credit Agreement was $129.1 million and we had $111.0 million of debt outstanding, consisting of $105.0 million under the Term Loan and $6.0 million under the Revolving Loan, providing us with $9.0 million in unused borrowing capacity under the Revolving Loan. We are required to make mandatory payments of outstanding principal on the Term Loan of $10.0 million per fiscal quarter. If a borrowing base deficiency exists at any time during the period from April 1, 2021 through and including May 14, 2021, we will be required to make a mandatory payment in an amount sufficient to eliminate any continuing borrowing base deficiency, subject to certain adjustments. If a borrowing base deficiency exists on or after May 15, 2021, and such borrowing base deficiency has not been eliminated on or before the 45th day after such deficiency, we will be required to pay an amount sufficient to eliminate any borrowing base deficiency on the 45th day after such borrowing base deficiency. There were no letters of credit outstanding under our Credit Agreement as of December 31, 2020.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the London interbank offered rate ("LIBOR") plus an applicable margin between 2.50% and 3.00% per annum based on net debt to EBITDA or (ii) a domestic bank rate ("ABR") plus an applicable margin between 1.50% and 2.00% per annum based on net debt to EBITDA plus (iii) a commitment fee of 0.500% per annum based on the unutilized maximum revolving credit. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants, including the Transaction Covenant described below, that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions.

In addition, we are required to maintain the following financial covenants:

- current assets to current liabilities of at least 1.0 to 1.0 at all times; and
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 3.5 to 1.0.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

Our partnership agreement prohibits us from paying any distributions on our common units until we have redeemed all of the Class C Preferred Units. Following such redemption, the Credit Agreement further limits our ability to pay distributions to unitholders.

The Partnership's inability to generate sufficient liquidity to meet future debt obligations raises substantial doubt regarding our ability to continue as a going concern. The Credit Agreement matures September 30, 2021 and our ability to continue as a going concern is dependent upon our ability to either (i) refinance or extend the maturity of the Credit Agreement, or (ii) obtain adequate new debt or equity financing to repay the Credit Agreement in full at maturity. The Tenth Amendment provides that the Partnership's audited annual financial statements may be delivered with a "going concern" or like qualification or exception, if such qualification or exception results from the fact that the final maturity date of the Amended Credit Agreement is less than one year after the date of such report, and does not otherwise include any qualification or exception as to the scope of such audit.

The Tenth Amendment contains the Transaction Covenant, which provides that we must either (i) engage an Advisory Firm to advise us with respect to a Qualifying Transaction, or, (ii) without an Advisory Firm, take material steps towards engaging in a Qualifying Transaction. If we engage an Advisory Firm, then the target closing date for a Qualifying Transaction must be no later than August 31, 2021. If we take material steps on our own, then the target closing date for a Qualifying Transaction must be on or before June 30, 2021 or we must hire an Advisory Firm. In either event, the net cash proceeds must be reasonably expected to be greater than the full amount due under the Credit Agreement on the maturity date. If we are unable to comply with the Transaction Covenant it will be deemed an immediate event of default under the Credit Agreement, which could cause all of our existing indebtedness to become immediately due and payable. Please read "Part I, Item 1A. Risk Factors—Our Credit Agreement has substantial prepayment requirements, other restrictions and financial covenants and requires periodic borrowing base redeterminations."

At December 31, 2020, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Sources of Debt and Equity Financing

As of December 31, 2020, we had $6.0 million of debt outstanding under the Revolving Loan, leaving us with $9.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement at December 31, 2020. Our Credit Agreement matures on September 30, 2021.

Operating Cash Flows

We had net cash flows provided by operating activities for the year ended December 31, 2020, of approximately $37.9 million, compared to net cash flows provided by operating activities of approximately $58.0 million for the same period in 2019. This decrease was primarily related to the decrease in throughput between the periods which accounted for approximately $17.6 million of the decrease.

Our operating cash flows are subject to many variables, the most significant of which is the volume of oil and natural gas transported through our midstream assets, volatility of oil and natural gas prices and our level of production of oil and natural gas. Oil and natural gas prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future operating cash flows will depend on oil and natural gas transported through our midstream assets, as well as the market prices of oil and natural gas and our hedging program.

Investing Activities

We had net cash flows used in investing activities for the year ended December 31, 2020 of approximately $1.9 million, consisting of approximately $1.8 million related to midstream activities, including pipeline construction, and contributions to Carnero JV totaling approximately $0.1 million.

Our net cash flows used in investing activities for the year ended December 31, 2019 were approximately $1.4 million, consisting of approximately $1.0 million related to midstream activities, including pipeline construction, and contributions to Carnero JV totaling approximately $0.2 million.

Financing Activities

Net cash flows used in financing activities was approximately $39.4 million for the year ended December 31, 2020. During the year ended December 31, 2020, we repaid $39.0 million of borrowings under the Credit Agreement.

Net cash flows used in financing activities were approximately $54.4 million for the year ended December 31, 2019. During the year ended December 31, 2019, we distributed approximately $17.7 million to Stonepeak Catarina, as the holder of all of our outstanding Class B Preferred Units, and approximately $5.2 million to our common unitholders. Additionally, we paid approximately $0.2 million in offering costs and repaid $34.0 million of borrowings under the Credit Agreement.

Going Concern

Our historical consolidated financial statements have been prepared under the assumption that we will continue as a going concern. The report on our audited consolidated financial statements for the year ended December 31, 2020, issued by our independent registered public accounting firm included in this Form 10-K, includes an explanatory paragraph referring to our inability to generate sufficient liquidity to meet future debt obligations which raises substantial doubt about our ability to continue as a going concern. Our ability to continue as a going concern is dependent upon our ability to either (i) refinance or extend the maturity of the Credit Agreement, or (ii) obtain adequate new debt or equity financing to repay the Credit Agreement in full at maturity. Our consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty. The outcome of these matters cannot be predicted with any certainty at this time and raise doubt that we will be able to continue as a going concern. Our consolidated financial statements do not include any adjustments to the amount and classification of assets and liabilities that may be necessary should we be unable to continue as a going concern.

Off-Balance Sheet Arrangements

As of December 31, 2020, we had no off-balance sheet arrangements with third parties, and we maintain no debt obligations that contained provisions requiring accelerated payment of the related obligations in the event of specified levels of declines in credit ratings.

Credit Markets and Counterparty Risk

We actively monitor the credit exposure and risks associated with our counterparties. Additionally, we continue to monitor global credit markets to limit our potential exposure to credit risk where possible. Our primary credit exposures result from the generation of substantially all of our midstream business segment revenues from a single customer, Mesquite, the sale of oil and natural gas and our use of derivatives.

On August 11, 2019, the SN Debtors filed voluntary petitions for reorganization under Chapter 11 of the United States Bankruptcy code in the Bankruptcy Court, jointly administered under Case No. 19-34508 (the "Mesquite Chapter 11 Case"). On January 13, 2020, we received written notice of termination from Mesquite terminating the Seco Pipeline Transportation Agreement, effective February 12, 2020. On June 30, 2020, the SN Debtors emerged from the Mesquite Chapter 11 Case, with Mesquite Company becoming a privately held corporation. Given our midstream focus, our primary credit exposure relates to the creditworthiness of the counterparties under our gathering and processing agreements including, among other counterparties, Mesquite.

On June 6, 2020 the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, which will become effective only upon satisfaction of certain closing conditions described in the Settlement Agreement unless terminated earlier.

On June 23, 2020, certain affiliates of each Occidental Petroleum Corp., The Blackstone Group and GSO Capital Partners filed the Rejection Lawsuits against Mesquite and certain of its subsidiaries requesting, among other things, that the Bankruptcy Court not approve the rejection of certain commercial agreements, as set forth in the Settlement Agreement, in connection with Mesquite's Comanche Asset. The commercial agreements contemplated by the Settlement Agreement that the Partnership and its subsidiaries entered into on June 30, 2020 will not become effective until, among other things, the Rejection Lawsuits have been resolved in favor of the SN Debtors and the Bankruptcy Court has approved the rejection of the certain commercial agreements underlying the Rejection Lawsuits. The Rejection Lawsuits were not resolved by October 1, 2020, and as a result the parties to the Settlement Agreement may terminate the Settlement Agreement at any time pursuant to its terms. To date, none of the parties of the Settlement Agreement have provided notice of termination.

Any development that materially and adversely affects Mesquite's operations or financial condition, including the failure to favorably resolve the Rejections Lawsuits or termination of the Settlement Agreement, could have a material adverse impact on us, including but not limited to impairment losses on fixed assets. For additional information on the risks associated with our relationships with Mesquite, please read "Part I, Item 1A. Risk Factors."

Credit Agreement

As of December 31, 2020, the banks and their percentage commitments in our Credit Agreement were: Royal Bank of Canada (13%), BBVA USA f/k/a Compass Bank (12%), Truist Bank f/k/a SunTrust Bank (12%), Capital One, National Association (12%), Comerica Bank (12%), Citibank, N.A. (9%), Credit Suisse AG, Cayman Islands (9%), ING Capital LLC (9%), CIT Bank, N.A. (9%) and Macquarie Investments US Inc. (5%). As of December 31, 2020, each of these financial institutions had an investment grade credit rating.

Critical Accounting Policies and Estimates

The discussion and analysis of our 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 of America. The preparation of the financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in the calculation of depletion and impairment of oil and natural gas properties, the fair value of commodity derivative contracts and asset retirement obligations, accrued oil and natural gas revenues and expenses and the allocation of general and administrative expenses. Actual results could differ materially from those estimates.

The policies disclosed included the accounting for oil and natural gas properties, oil and natural gas reserve quantities, revenue recognition and hedging activities. Please read Note 2 “Basis of Presentation and Summary of Significant Accounting Policies” to our consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold and proved property acquisition costs using all proved reserves. As more fully described in Note 7 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

All other properties, including gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

Estimated asset retirement costs are recognized when the asset is acquired or placed in service. Costs associated with oil and natural gas properties are amortized over proved reserves using the units-of-production method. Costs associated with gathering and transportation assets are depreciated using the straight-line method over the useful lives of the asset. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. Cash flow estimates for the impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 7 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements for additional information.

Gathering and transportation assets are reviewed for impairment when facts or circumstances indicate that their carrying value may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows, we recognize an impairment equal to the excess of net book value over fair value. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our gathering and transportation assets and the recognition of additional impairments. Refer to Note 7 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements for additional information.

Reserves of Natural Gas, NGLs and Oil

Our estimate of proved reserves is based on the quantities of natural gas, NGLs and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of the reserve report prepared by Ryder Scott, an independent oil and natural gas consulting firm. On an annual basis, our proved reserve estimates and the reserve report prepared by Ryder Scott are reviewed by the Audit Committee and the Board. Our financial statements for 2020 and 2019 were prepared using Ryder Scott's estimates of our proved reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the actual quantities of oil and natural gas eventually recovered.

Recent Accounting Pronouncements and Accounting Changes

See Note 2 "Basis of Presentation and Summary of Significant Accounting Policies" to our consolidated financial statements included in this report for information on new accounting pronouncements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information required by this Item.

Item 8. Financial Statements and Supplementary Data

The information required by this Item is included in this report as set forth in the "Index to Consolidated Financial Statements" beginning on page F-1 of this Form 10-K and is incorporated by reference herein.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, with the Partnership have been detected. These inherent limitations include error by personnel in executing controls due to faulty judgment or simple mistakes, which could occur in situations such as when personnel performing controls are new to a job function or when inadequate resources are applied to a process. Additionally, controls can be circumvented by the individual acts of some persons or by collusion of two or more people.

The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no absolute assurance that any design will succeed in achieving its stated goals under all potential future conditions; over time, controls may become inadequate because of changes in conditions or personnel, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the principal executive officer and principal financial officer of our general partner, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this Form 10-K. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including the principal executive officer and principal financial officer of our general partner, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. The principal executive officer and principal financial officer of our general partner have concluded that our current disclosure controls and procedures were effective as of December 31, 2020 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting

During the three months ended December 31, 2020, there were no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Reports of Management

Financial Statements

The management of our general partner is responsible for the information and representations in our financial statements. We prepare the financial statements in accordance with accounting principles generally accepted in the United States of America based upon available facts and circumstances and management's best estimates and judgments of known conditions.

The Audit Committee, which consists of two independent directors, meets periodically with management, our internal auditor and KPMG LLP to review the activities of each in discharging their responsibilities. Our internal auditor and KPMG LLP have free access to the Audit Committee.

Management's Report on Internal Control Over Financial Reporting

Our management, under the direction of the principal executive officer and principal financial officer of our general partner, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) of the Exchange Act.

Our system of internal control over financial reporting is designed to provide reasonable assurance to our management and the Board regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

The management of our general partner conducted an evaluation of the effectiveness of our internal control over financial reporting using the framework in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). As noted in the COSO framework, an internal control system, no matter how well conceived and operated, can provide only reasonable-not absolute-assurance to management and the Board regarding achievement of an entity's financial reporting objectives. Based upon the evaluation under this framework, management concluded that our internal control over financial reporting was effective as of December 31, 2020.

Report of Independent Registered Public Accounting Firm

Please see Report of Independent Registered Public Accounting Firm beginning on Page F-2 of this Form 10-K.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The following table shows information for members of the Board and the executive officers of our general partner as of March 16, 2021. All of the directors of our general partner are elected by SP Holdings, as the sole member of our general partner, except for two persons who are appointed by Stonepeak Catarina pursuant to the Representation and Standstill Agreement. Members of the Board hold office until their successors have been elected or qualified or until the earlier of their death, incapacity, resignation or removal. Executive officers hold office at the discretion of, and may be removed by, the Board.

Name	Age	Position with Evolve Transition Infrastructure LP
Alan S. Bigman	53	Independent Director
Michael Bricker	32	Director
Jack Howell	34	Director
Richard S. Langdon	70	Independent Director
Steven E. Meisel	36	Independent Director
John T. Steen III	40	Director; Chairman of the Board
Luke R. Taylor	43	Director
Charles C. Ward	60	Chief Financial Officer and Secretary
Gerald F. Willinger	53	Director; Chief Executive Officer

Alan S. Bigman was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in July 2014. Mr. Bigman is an independent member of the Conflicts Committee of our general partner and is the Chair of the Audit Committee of our general partner. Mr. Bigman currently serves as an independent non-executive director and chairman of the audit committee of a $1.5 billion dollar privately held chemicals company. His extensive board experience also includes Basell Polyolefins, an international chemical producer and predecessor of LyondellBasell, where he served as a non-executive director before his appointment as Chief Financial Officer, and Svyazinvest, then Russia's largest telecom company, as well as several others. Mr. Bigman's executive experience includes fourteen years in positions with Access Industries, a privately-held, U.S.-based industrial group, and in senior positions with its portfolio companies. From June 1996 to March 1998, Mr. Bigman was Senior Vice President of Access Industries, overseeing strategic investments. From March 1998 until September 2003, Mr. Bigman served as Vice President and Director of Corporate Finance of Tyumen Oil Company (TNK), a major Russian oil and gas producer and refiner, where he raised over $5 billion to finance the growth of the company from its privatization in 1997 through a sale of a 50% stake to British Petroleum (BP) in 2003, creating TNK-BP, a $20 billion joint venture. From 2003 to 2004, he served as Vice President and Director of Corporate Finance for SUAL, a large Russian aluminum smelter, where he reorganized the finance function and executed strategic merger transactions. From September 2004 until December 2005, Mr. Bigman rejoined Access Industries as Senior Vice President. In January 2006, Mr. Bigman was appointed Chief Financial Officer of Basell Polyolefins, an international chemicals company based in The Netherlands, where he served through 2007 and co-led the acquisition of Lyondell to create one of the largest global chemical companies. In January 2008, Mr. Bigman was appointed Chief Financial Officer of LyondellBasell Industries, the successor company to Basell Polyolefins and Lyondell. LyondellBasell's US operations filed for bankruptcy in January 2009. Mr. Bigman continued to serve as Chief Financial Officer until August 2009, and worked for the company in a project role through March 2010. From 2011 through 2012, he served on a project basis as Director, Capital Markets and M&A of KCAD Deutag, an oilfield services company based in Aberdeen, UK, where he was responsible for reorganizing and staffing the company's finance, corporate development and tax functions.

Michael Bricker was appointed as a member of the Board in September 2020. Mr. Bricker is currently a Managing Director at Stonepeak and has been with Stonepeak since April 2017. Mr. Bricker currently serves as a member of the Operating Committee for Whistler Pipeline, a greenfield natural gas pipeline, and Oryx Midstream Services LLC, the owner and operator of a crude oil pipeline system, both located in the Permian Basin. From April 2014 to April 2017, Mr. Bricker was an Investment Associate with First Reserve Corporation, a private equity firm that focuses on energy infrastructure investments. Mr. Bricker started his career as an Analyst in Citigroup's oil and gas investment banking group. Mr. Bricker holds a Master in Professional Accounting with a Minor in Finance, graduating with high honors from the University of Texas at Austin.

Jack Howell was elected as a member of the Board in October 2015. Mr. Howell is a Senior Managing Director at Stonepeak and a member of Stonepeak's Executive Committee. Mr. Howell has been with Stonepeak since 2015. Prior to joining Stonepeak, Mr. Howell covered the oil and gas sector for Davidson Kempner, a hedge fund that focuses on distressed investments, from 2014 to 2015. Prior to Davidson Kempner, Mr. Howell worked for Denham Capital, an energy-focused private equity firm from 2011 to 2014. Mr. Howell started his career as an Analyst in Credit Suisse's oil and gas investment banking group. Mr. Howell holds a Bachelor of Arts degree in Plan II Honors and Business Economics, Phi Beta Kappa, from the University of Texas at Austin.

Richard S. Langdon was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in December 2006. Mr. Langdon is an independent member of the Audit Committee and the Conflicts Committee. Mr. Langdon is currently the Executive Vice President and Chief Financial Officer of Altamont Energy LLC, a privately held exploration and production company, a position he has held since April 2018. Mr. Langdon previously served as the President and Chief Executive Officer of Badlands Energy, Inc., a privately held exploration and production company ("Badlands Energy"), and its publicly traded predecessor entity, Gasco Energy, Inc. ("Gasco"), from May 2013 to October 2018. Mr. Langdon also served as a director of Badlands Energy and its predecessor, Gasco from March 2003 to October 2018. Badlands Energy filed for bankruptcy in August 2017. In addition to his Badlands Energy titles, Mr. Langdon also served as Debtor-in-Possession for Badlands Energy from August 2017 to October 2018. Mr. Langdon also currently serves on the board of directors, as chairman of the audit committee and as a member of the compensation committee of Gulfslope Energy, Inc., which capacities he has served in since March 2014. Mr. Langdon was the President and Chief Executive Officer of KMD Operating Company LLC ("KMD Operating"), a privately held production company, from November 2011 until December 2015 and Matris Exploration Company L.P., a privately held production company, from July 2004 until the merger of Matris Exploration into KMD Operating in November 2011, which merger was effective January 2011. Mr. Langdon also served as President and Chief Executive Officer of Sigma Energy Ventures, LLC, a privately held production company, from November 2007 until November 2013. From 1997 until 2002, Mr. Langdon served as Executive Vice President and Chief Financial Officer of EEX Corporation, a publicly traded exploration and production company that merged with Newfield Exploration Company in 2002. Prior to that, he held various positions with the Pennzoil Companies from 1991 to 1996, including Executive Vice President—International Marketing—Pennzoil Products Company; Senior Vice President—Business Development—Pennzoil Company; and Senior Vice President—Commercial & Control—Pennzoil Exploration & Production Company.

Steven E. Meisel was appointed as a member of the Board in September 2020 and is an independent member of the Board. Mr. Meisel also historically provided consulting services to the Partnership and its subsidiaries through that certain Consultancy Agreement (the "Meisel Consulting Agreement") entered into with our general partner, effective as of October 1, 2020. The Meisel Consulting Agreement was terminated in March 2021. Mr. Meisel is Co-Chief Executive Officer and Managing Partner of Discovery Midstream Holdings II LLC ("Discovery II"). Prior to joining Discovery II, Mr. Meisel co-founded Discovery Midstream Holdings LLC ("Discovery I") in January 2016, and grew a small greenfield G&P project into the premier system on the southern side of the DJ Basin. The asset was sold to Williams and KKR in August 2018 for $1.2B. From March 2012 to January 2016, Mr. Meisel served as Senior Vice President of Commercial and Business Development at Wildcat Midstream Partners LLC, leading the commercial efforts in North Louisiana while also securing Wildcat's Southern Midland Basin oil pipeline project. Prior to Wildcat, Mr. Meisel worked in various capacities for Regency Energy including corporate development, corporate finance and business development. Mr. Meisel started his career as an Analyst in Southwest Securities investment banking group. Mr. Meisel has a Bachelor of Finance from the University of Kansas.

John T. Steen III, was appointed as a member of the Board in September 2020 and currently serves as the Chairman of the Board. Mr. Steen also historically provided consulting services to the Partnership and its subsidiaries through the JT3 Consulting Agreement defined and described in "Part III, Item 13. Certain Relationships and Related Transactions and Director Independence—Related Party Transactions—2020—JT3 Consulting Agreement." The JT3 Consulting Agreement was terminated in March 2021. Mr. Steen is also currently a Senior Operating Partner with Stonepeak Infrastructure Partners and supports Stonepeak's efforts in the midstream energy sector. Prior to joining Stonepeak, from 2017 to 2018, Mr. Steen was CEO of Paradigm Energy Partners, which focused on oil and gas pipeline and storage assets in the Bakken Shale of North Dakota and the Eagle Ford Shale of South Texas. From 2012 to 2017, Mr. Steen was a Vice President for Sage Midstream. Prior to Sage Midstream, Mr. Steen worked in various midstream business development capacities for Energy Transfer and LDH Energy. He is the Chairman of the Texas Racing Commission, which oversees all pari-mutuel wagering on horse and greyhound racing in the state of Texas. Mr. Steen also serves on the boards of Oryx Midstream Services LLC and King Ranch, Inc. He graduated cum laude from Vanderbilt University and received an MBA from the Wharton School as well as an MA in International Studies from the University of Pennsylvania. Mr. Steen is also a CFA charterholder.

Luke R. Taylor was elected as a member of the Board in October 2015. Mr. Taylor has served as a Senior Managing Director with Stonepeak since August 2011 and serves as a member of Stonepeak's Executive Committee. Mr. Taylor has been investing across the infrastructure space for over 15 years and sits on the boards of Lineage Logistics, Golar Power and Ironclad Energy Partners, and is a former director of Paradigm Energy Partners, Tidewater Holdings, Carlsbad Desalination Project, Casper Crude to Rail and Northstar Renewable Power. Prior to joining Stonepeak, Mr. Taylor was a Senior Vice President with Macquarie Capital based in New York. Mr. Taylor has a Bachelor of Commerce and a Master of Business (Distinction) from the University of Otago (New Zealand).

Charles C. Ward was elected Chief Financial Officer and Secretary of our general partner in March 2015. Mr. Ward previously served as Chief Financial Officer and Treasurer of Sanchez Production Partners LLC from March 2008 until its conversion to a limited partnership in March 2015 and Secretary from July 2014 until March 2015. Mr. Ward also served as a Vice President of Constellation Energy Commodities Group, Inc. from November 2005 until December 2008. Prior to that time, he was a Vice President of Enron Creditors Recovery Corp. from March 2002 to November 2005.

Gerald F. Willinger was elected as a member of the Board in March 2015 and was previously a director of Sanchez Production Partners LLC, having been first elected in August 2013. Mr. Willinger was elected Interim Chief Executive Officer of our general partner in April 2015 and Chief Executive Officer in December 2015. From July 2014 until May 2020, Mr. Willinger served as Executive Vice President of SOG. From February 2010 until May 2020, Mr. Willinger served as a Managing Director of Sanchez Capital Advisors, LLC. Prior to joining Sanchez Capital Advisors, LLC, Mr. Willinger was a Senior Analyst for Silver Point Capital, LLC, a credit-opportunity fund, from 2006 to 2009. Mr. Willinger was also a co-founder, officer and director of Sanchez Resources from February 2010 to November 2017 when Sanchez Resources was acquired by Mesquite. From 2000 to 2003, Mr. Willinger served in various private equity investment management roles at MidOcean Partners, LLC and its predecessor entity, DB Capital Partners, LLC. From 1998 to 2000, Mr. Willinger was an investment banker with Goldman, Sachs & Co.

Messrs. Steen, Bricker and Meisel were appointed to serve as directors on the Board in September 2020. Messrs. Howell and Taylor were elected as members of the Board in October 2015 pursuant to that certain Board Representation and Standstill Agreement, by and among us, our general partner and Stonepeak Catarina, which was subsequently amended and restated by that certain Amended and Restated Board Representation and Standstill Agreement, dated as of August 2, 2019, by and among us, our general partner and Stonepeak Catarina (as amended and restated, the "Representation and Standstill Agreement"). Pursuant to the Representation and Standstill Agreement, we and our general partner agreed to permit Stonepeak Catarina to designate two persons to serve on the Board. The right to designate one Board member will immediately terminate on such date as Stonepeak Catarina no longer owns at least 25% of the Partnership's outstanding Class C Preferred Units issued to it; and the right to designate the second Board member will immediately terminate on such date as Stonepeak Catarina does not hold any issued and outstanding Class C Preferred Units. Stonepeak Catarina also has the right to appoint the three independent members to the Board if all of the Class C Preferred Units have not been redeemed by December 31, 2021, with such right continuing until all Class C Preferred Units have been redeemed.

Qualifications of the Board of Directors

The sole member of our general partner elects all of the members of the Board, except for two members designated by Stonepeak Catarina pursuant to the Representation and Standstill Agreement. The following sets forth the specific experience, qualifications, attributes and skills that led the sole member of our general partner to conclude that the persons appointed by it should serve as directors:

Mr. Bigman brings considerable financial, managerial, transaction and corporate governance experience to the Board. During his career, he has held management positions of increasing responsibility in major energy corporations throughout the world where he has successfully lead financings, financial restructurings, mergers and acquisitions involving companies focused on various aspects of the hydrocarbon value chain. With respect to energy finance, as Vice President and Director of Corporate Finance for TNK, a leading Russian oil and gas producer, he raised capital to finance the growth of the company from its privatization in 1997 through a sale of a 50% stake to British Petroleum (BP) in 2003, creating TNK-BP, a $20 billion joint venture. In the area of corporate governance, Mr. Bigman served on the board of directors of Basell Polyolefins, where he was a member of the audit and compensation committees, which is beneficial for our board operations. He has also served on several international boards, including the board of Svyazinvest, Russia's largest telecommunications holding company, and JKX Oil and Gas, a UK public company focused on international oil and gas assets. The Board, after review and discussion of the applicable NYSE American listing standards and requirements, has determined that Mr. Bigman is "independent" for purposes of service on the Board.

Mr. Bricker brings extensive investing and corporate finance experience to the Board, as well as a depth of knowledge of the upstream and midstream oil and gas industry. Mr. Bricker also bring substantial experience in mergers and acquisitions to the Board.

Mr. Langdon brings 47 years of management experience in energy banking, energy consulting and executive management and board experience in large and small, public and private, domestic and international energy companies to the Board. He has served as the Chief Financial Officer of EEX Corporation, a publicly traded production company that merged with Newfield Exploration. He has also held significant commercial positions with the Pennzoil Companies, including roles in business development and marketing. He was also the founder and owner of two privately held oil and gas companies. Mr. Langdon has extensive experience in finance and accounting that adds significant value to the board's oversight role of our financial reporting. He has prior public company board and audit committee experience, which is beneficial for our board operations, and served as the chairman of the audit committee of Gasco until he was named Gasco's President and Chief Executive Officer. The Board, after review and discussion of the applicable NYSE American listing standards and requirements, has determined that Mr. Langdon is "independent" for purposes of service on the Board.

Mr. Meisel brings expansive operating and management experience with respect to gathering, processing, treating and transmission infrastructure to the Board. He also brings extensive experience executing corporate finance transactions and corporate development transactions including acquisitions, divestitures, capital raises and project development transactions to the Board. The Board, after review and discussion of the applicable NYSE American listing standards and requirements, has determined that Mr. Meisel is "independent" for purposes of service on the Board.

Mr. Steen brings extensive operational, management and business development experience with respect to pipeline, storage and other midstream infrastructure assets to the Board. Mr. Steen also brings experience with respect to negotiation of commercial contracts and commercial projects to the Board.

Mr. Willinger brings substantial experience in risk management, finance and negotiated transactions in the energy industry to the Board. He has a valuable perspective on master limited partnerships, which provides the Board with unique insights into master limited partnership management and growth opportunities. In addition, he brings an expansive network of both private and public capital providers, which is useful for the Board when evaluating possible capital sources.

The following sets forth the specific experience, qualifications, attributes and skills that led the holders of our Class C Preferred Units to conclude that the persons appointed by them should serve as directors:

Mr. Howell brings extensive oil and gas investing experience, along with experience in oil and gas transaction financings and mergers and acquisitions to the Board.

Mr. Taylor brings significant investment experience in energy and infrastructure companies, along with experience in finance and mergers and acquisitions to the Board.

Committees of the Board of Directors

The Board has two standing committees: the Audit Committee and the Conflicts Committee. We do not have a compensation committee, but rather the Board approves executive officer salary changes and bonuses and equity grants to directors, executive officers, employees and service providers.

Audit Committee

As described in its charter, the Audit Committee is directly responsible for the appointment, compensation, retention and oversight of the work of the independent public accountants to audit our financial statements, including assessing the independent auditor's qualifications and independence, and establishes the scope of, and oversees, the annual audit. The Audit Committee also approves any other services provided by public accounting firms. The Board has delegated to the Audit Committee the review and approval of our decision to enter into derivative transactions and our exemption from the swap clearing and swap execution requirements of the Dodd-Frank Act. The Audit Committee provides assistance to the Board in fulfilling its oversight responsibility to the unitholders, the investment community and others relating to the integrity of our financial statements, our compliance with legal and regulatory requirements, the independent auditor's qualifications and independence and the performance of our internal audit function. The Audit Committee oversees our system of disclosure controls and procedures and system of internal controls regarding financial, accounting, legal compliance and ethics that management and the Board established. In doing so, it is the responsibility of the Audit Committee to maintain free and open communication between the committee and our independent auditors, the internal accounting function and our management.

Messrs. Bigman (Chair) and Langdon are members of the Audit Committee. The Board has determined that each of Messrs. Bigman and Langdon is an "audit committee financial expert" as that term is defined in the applicable rules of the SEC. Additionally, the Board has also determined that each of Messrs. Bigman and Langdon is "independent" for purposes of service on the Audit Committee as required by applicable NYSE American listing standards.

Conflicts Committee

The Conflicts Committee consists of Messrs. Langdon (Chair) and Bigman. The Conflicts Committee reviews specific matters that the Board believes may involve conflicts of interest. Our partnership agreement provides that members of the Conflicts Committee may not be officers or employees of our general partner or directors, officers or employees of any of our General Partner's affiliates or, subject to certain exceptions, a holder of any ownership interest in our General Partner or its affiliates and must meet the independence standards for service on an audit committee of a board of directors as established by NYSE American and SEC rules. Any matters approved by the Conflicts Committee will be presumed to be taken in good faith.

Other

We maintain on our website, http://www.evolvetransition.com, a copy of the Audit Committee charter as well as copies of the Corporate Governance Guidelines and Code of Business Conduct and Ethics that are applicable to us and our general partner. Copies of these documents are also available in print and may be obtained without charge, upon written request, by emailing our investor relations group at ir@evolvetransition.com. Our Code of Business Conduct and Ethics applies to our general partner's principal executive officer, principal financial officer and principal accounting officer, among others. We intend to post any changes to or waivers of our Code of Business Conduct and Ethics for the executive officers of our general partner on our website.

Certifications

The NYSE American requires the Chief Executive Officer of each listed company to certify annually that he is not aware of any violation by a listed company of the NYSE American's corporate governance listing standards, qualifying the certification to the extent necessary. In accordance with the rules of the NYSE American, we last provided such a certification on March 13, 2020. The certifications of the Chief Executive Officer and Chief Financial Officer of our general partners required by Sections 302 and 906 of the Sarbanes-Oxley Act have been included as exhibits to this Form 10-K.

Item 11. Executive Compensation

Our general partner has the sole responsibility for conducting our business and for managing our operations, and its Board makes decisions on our behalf. The executive officers of our general partner are employed by SOG and manage the day-to-day affairs of our business.

Summary Compensation Table

The following table sets forth the compensation of our named executive officers (which are the chief executive officer and the two next most highly compensated officers of our general partner) for 2020 and 2019:

Name and Principal Position	Year	Salary	Bonus (a)	Unit Awards (b)	All Other Compensation (c)	Total
Gerald F. Willinger	2020	$ 600,000	$ 1,300,000	$ —	$ 55,260	$ 1,955,260
Chief Executive Officer (e)	2019	$ 600,000	$ 750,000	$ 1,502,953	$ 60,229	$ 2,913,182
Patricio D. Sanchez	2020	$ 274,243	$ —	$ —	$ 15,367	$ 289,610
President & Chief Operating Officer (e)	2019	$ 400,000	$ —	$ —	19,273	$ 419,273
Charles C. Ward	2020	$ 375,000	$ 550,000	$ —	$ 54,792	$ 979,792
Chief Financial Officer and Secretary (e)	2019	$ 375,000	$ 350,000	$ 635,864	$ 45,367	$ 1,406,231

(a) On March 13, 2020, our general partner entered into the Award Letter Agreements (as defined below) with each of Messrs. Willinger and Ward. In the Award Letter Agreements the Board determined that the annual grant for 2020 of $1,300,000 to Mr. Willinger and $550,000 to Mr. Ward would be payable either in cash or restricted units under the Plan. The Award Letter Agreements also provided that the form of the award was to be determined in the sole discretion of the Board prior to March 1, 2021. On March 1, 2021, Messrs. Willinger and Ward agreed with our general partner to delay the determination as to the form of their respective awards until a time prior to March 31, 2021.

(b) On August 2, 2019, the Board approved the Partnership's entry into Executive Agreements (defined below) with each of Messrs. Willinger and Ward. The Executive Agreements contain annual cash bonuses for services rendered by each of Messrs. Willinger and Ward and provide that 50% of such annual bonuses shall be paid no later than September 30 of the year for which such annual bonus relates, with the remainder, including any true-up and changes determined by the Board, shall be paid no later than March 31 of the year following the year for which such annual bonus relates. With respect to annual bonuses for 2020, Messrs. Willinger and Ward have agreed with our general partner to defer the determination and payment of their annual cash bonuses. With respect to annual bonuses for 2019, Messrs. Willinger and Ward were paid cash bonuses of $750,000 and $350,000, respectively.

(c) The amounts reported in this column reflect the aggregate grant date fair value of awards granted, if any, under our Plan for fiscal years 2020 and 2019, computed in accordance with FASB ASC Topic 718, excluding estimated forfeitures. See Note 14 "Unit-Based Compensation," to the Consolidated Financial Statements included under "Part II, Item 8. Financial Statements and Supplementary Data" for additional detail regarding these figures. On March 4, 2019, the Board awarded Messrs. Willinger and Ward long-term incentive awards, which were paid in the form of restricted units under the Plan that vest in equal installments over three years.

(d) The amount in this column reflects the amount of matching contributions made under our 401k plan; parking cost paid for our executive officers; the cost of life insurance, accidental death and dismemberment insurance, and health insurance for our executive officers; and for those executive officers who also serve as directors, this column includes cash fees they received for service as a director.

(e) Our named executive officers are eligible to participate in benefit plans such as medical, dental, vision, life and disability insurance, 401k and flexible spending accounts on the same terms as all employees or service providers.

(f) On September 8, 2020, Mr. Sanchez resigned from his position as President and Chief Operating Officer, effective as of September 8, 2020. As a result, the salary amount for Mr. Sanchez for 2020 has been prorated based on salary paid from January 1, 2020 through September 8, 2020.

Executive Agreements

Executive Services Agreements

On August 2, 2019, our general partner entered into Executive Services Agreements with each of Messrs. Willinger and Ward (each, an "Executive Agreement" and, collectively, the "Executive Agreements"). The Executive Agreements were approved by the Board on August 2, 2019. Each respective Executive Agreement provides (i) that the applicable executive will continue to serve in his current executive officer position with our general partner and provide services to us and our general partner during the applicable term, (ii) for an annual base salary (Mr. Willinger: $600,000 and Mr. Ward: $375,000), (iii) for an annual cash bonus equal to a percentage of the annual base salary (Mr. Willinger: 100%-150% and Mr. Ward: 75%-125%) based on a qualitative assessment of financial and individual performance achievements, and (iv) for eligibility to receive awards under our Plan or any successor thereto and to participate in any long-term incentive programs available generally to the executive officers of our general partner, as determined in the sole discretion of the Board. Under each Executive Agreement, in the event of the applicable executive's termination as an officer of the general partner due to (a) such executive's death or "disability," (b) the general partner terminating such executive without "cause," or (c) such executive terminating for "good reason" (as such terms are defined in the Executive Agreements), such executive (or such executive's designated beneficiaries, as applicable) will be entitled to receive payment of: (i) any accrued but unpaid then-current annual base salary through the date of termination, (ii) any unpaid annual bonus for the year prior to the year of termination and (iii) a pro-rated annual bonus for the year of termination. In addition, such executive will also be entitled to receive the following severance payments or benefits in the event of: (1) the general partner terminating such executive without "cause," (2) such executive terminating for "good reason" or (3)(A) the general partner terminating such executive without "cause," (B) such executive's death or "disability," or (C) such executive terminating for any reason, in the case of (A)-(C), during a period beginning 60 days prior to and ending two years following a Change in Control (as defined in the Executive Agreements) such executive will be entitled to receive (w) a lump-sum cash payment equal to two times such executive's then-current annual base salary plus two times the largest annual bonus paid (or due to be paid) to such executive for the year in which the termination occurs or any year in the three calendar year period immediately preceding the date of termination, (x) payment of the COBRA premiums for such executive and such executive's eligible dependents during the COBRA continuation period, (y) to the extent not yet paid to such executive, a lump-sum cash payment equal to all outstanding amounts owed to such executive for services performed for or on behalf of us and our general partner, the amount of such executive's annual bonus for the last full year during which such executive performed services for us and our general partner, and the amount of such executive's annual bonus for the current year, based on such executive's annual bonus for such last full year (pro-rated to the date of termination), and (z) immediate vesting in full, as of the date of such Change in Control, of any units awarded to such executive under our Plan. On March 1, 2021, Messrs. Willinger and Ward agreed with our general partner to defer the determination and payment of their annual cash bonuses for 2020.

On March 13, 2020, our general partner entered into an Award Letter Agreement with each of Messrs. Willinger and Ward (each, an "Award Letter Agreement" and, together, the "Award Letter Agreements"). Pursuant to the Award Letter Agreements, the Board agreed with Messrs. Willinger and Ward to grant awards with respect to the performance of the Partnership in 2019 in amounts equal to $1,300,000 for Mr. Willinger, and $550,000 for Mr. Ward (the "Deferred Awards"). However, due to the declining market price of our common units from 2019 to 2020, the dilutive effect of granting awards to Messrs. Willinger and Ward under the Plan in March 2020 would have been extreme and in order to advance the interests of the Partnership and its unitholders, Messrs. Willinger and Ward agreed with our general partner to defer to determination on the form of the awards under the Award Letter Agreement until a time prior to March 1, 2021.

On March 1, 2021, Messrs. Willinger and Ward agreed with our general partner to delay the determination as to the form of the Deferred Awards until a time prior to March 31, 2021.

Outstanding Equity Awards at Fiscal Year-End 2020

The following table sets forth the outstanding equity awards and their market value using the closing price of our common units on NYSE American at December 31, 2020 for the named executive officers:

Name	Number of Units Not Vested	Fair Market Value of Units Not Vested[(a)]
Gerald F. Willinger	379,513[(b)]	$ 231,503
Charles C. Ward	163,011[(b)]	$ 99,437

(a) Amounts are based on the closing price of our common units of $0.61 as reported on the NYSE American on December 31, 2020.
(b) Reflects restricted units granted under the Plan on April 6, 2018, which units either vest on the first anniversary of the grant date or vest pro-rata over a three-year period and on their first anniversary, respectively, as well as units granted under the Plan on March 4, 2019, which units vest pro-rata over a three year period. See footnote (c) to the Summary Compensation Table for additional information on the vesting schedule for these units. Except in connection with a change in control (as defined in the Plan) or in the discretion of the board of directors of our general partner, any unvested restricted units will be forfeited upon such time as the holder is no longer an officer, employee, consultant or director of us, our general partner, any of their affiliates or any other person performing bona fide services for us.

Compensation of Directors

For the year ended December 31, 2020, compensation for the independent directors of the Board consisted of:

- a cash retainer of $35,000, payable quarterly on the last day of each fiscal quarter;
- a $1,500 fee for each meeting of the Board and $1,000 for each substantive meeting of the Audit Committee and $3,500 for each substantive meeting of the Conflicts Committee attended by a member thereof;
- a cash retainer of $3,500 for the Chair of the Audit Committee and $2,500 for the Chair of the Conflicts Committee, each payable quarterly on the last day of each fiscal quarter; and
- eligibility for independent directors to participate in a basic health benefits package similar to that available to all employees.

Messrs. Howell, Taylor, Bricker, Steen and Meisel do not receive separate compensation for their service on the Board, but they are entitled to indemnification related to their service as directors pursuant to the terms of our partnership agreement.

The following table sets forth a summary of the 2020 compensation for the directors except for Messrs. Willinger and P. Sanchez whose director compensation is included above under "—Summary Compensation Table":

	Director Compensation			
Name	Fees Earned or Paid in Cash	Unit Awards	All Other Compensation [a]	Total
Alan S. Bigman	$ 232,500	$ —	$ 25,511	$ 258,011
Michael Bricker [b]	$ —	$ —	$ —	$ —
Jack Howell [c]	$ —	$ —	$ —	$ —
Richard S. Langdon	$ 221,000	$ —	$ 3,903	$ 224,903
G. M. Byrd Larberg	$ 151,000	$ —	$ 11,994	$ 162,994
Steven E. Meisel [f]	$ —	$ —	$ —	$ —
Antonio R. Sanchez, III [d]	$ —	$ —	$ —	$ —
Eduardo A. Sanchez [d]	$ —	$ —	$ —	$ —
John T. Steen III [e]	$ —	$ —	$ —	$ —
Luke R. Taylor [c]	$ —	$ —	$ —	$ —

(a) All other compensation includes amounts for health, vision, dental, basic life and/or accidental death and dismemberment insurance premium fees paid by us for the director.
(b) Due to his employment with Stonepeak, Mr. Bricker does not receive any compensation for his service on the Board.
(c) As appointees of the holders of the Class C Preferred Units, Messrs. Howell and Taylor were not entitled to any compensation under our 2019 Board compensation program.
(d) As individuals with ownership interests in SP Holdings prior to the Stonepeak Transactions, Mr. A. Sanchez and Mr. E. Sanchez were not entitled to any compensation under our 2020 Board compensation program.
(e) Does not include compensation of $120,000 received under the JT3 Consulting Agreement during 2020.
(f) Does not include compensation of $37,500 received under the Meisel Consulting Agreement during 2020.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

The following table sets forth the beneficial ownership of our units, as of March 16, 2021, held by:

- each unitholder known by us to beneficially own more than 5% of our outstanding units;
- each of the directors of the Board;
- each of our general partner's named executive officers (as such term is defined by the SEC); and
- the directors and executive officers of our general partner as a group.

The list of persons named in the table below is derived from our review of Form 3, Form 4, Form 5, Schedule 13D and Schedule 13G filings made with the SEC as of March 16, 2020. The amounts and percentage of common units and Class C Preferred Units beneficially owned are reported on the basis of the SEC rules governing the determination of beneficial ownership of securities. Under the SEC rules, a person is deemed to be a "beneficial owner" of a security if that person has or shares "voting power," which includes the power to vote or to direct the voting of such security, and/or "investment power," which includes the power to dispose of or to direct the disposition of such security. A person is also deemed to be a beneficial owner of any securities of which that person has a right to acquire beneficial ownership within 60 days. Under these rules, more than one person may be deemed a beneficial owner of the same securities, and a person may be deemed a beneficial owner of securities as to which he has no economic interest.

Percentage of total units beneficially owned is based on 54,533,593 common units and 36,474,436 Class C Preferred Units outstanding as of March 16, 2021, the number of common units beneficially owned and the number of Class C Preferred Units beneficially owned is based upon ownership as of March 16, 2021, unless otherwise specified. Except as indicated by footnote, to our knowledge the persons named in the table below have sole voting and investment power with respect to all units shown as beneficially owned by them, subject to community property laws where applicable.

Name and address of Beneficial Owner(1)	Common Units Beneficially Owned		Class C Preferred Units Beneficially Owned		Percentage of Total Units Beneficially Owned
	Number	Percentage	Number	Percentage	
Stonepeak Catarina Holdings, LLC(2)	45,806,625	75.4 %	36,474,436	100 %	84.7 %
SN UR Holdings, LLC(3)	2,272,727	4.2 %	—	—	2.5 %
Invesco. Ltd(4)	1,747,546	3.2 %	—	—	*
Alan S. Bigman(5)	77,254	*	—	—	*
Jack Howell	—	—	—	—	—
Richard S. Langdon	81,827	*	—	—	*
Luke R. Taylor	—	—	—	—	—
Charles C. Ward	379,027	*	—	—	*
Gerald F. Willinger	1,101,183	2.0 %	—	—	1.2 %
All directors and executive officers as a group (6 persons)	1,639,291	3.0 %	—	—	1.8 %

* Less than 1%

(1) Unless otherwise set forth below, the address of all beneficial owners is c/o Evolve Transition Infrastructure LP, 1360 Post Oak Blvd, Suite 2400, Houston, Texas 77056.

(2) Ownership data as reported (i) on Form 4 filed on March 2, 2021, by Stonepeak Catarina, Stonepeak Catarina Upper Holdings LLC, Stonepeak Infrastructure Fund (Orion AIV) LP, Stonepeak Associates LLC, Stonepeak GP Holdings LP, Stonepeak GP Investors LLC, Stonepeak Texas Midstream Holdco LLC and Michael Dorrell, (ii) on Schedule 13D/A filed on February 1, 2021, by SPCE Sub, Stonepeak Catarina; Stonepeak Texas Midstream Holdco LLC; Stonepeak Catarina Upper Holdings LLC; Stonepeak Infrastructure Fund (Orion AIV) LP; Stonepeak Associates LLC; Stonepeak GP Holdings LP; Stonepeak GP Investors LLC; Stonepeak GP Investors Manager LLC; and Michael Dorrell, and (iii) publicly disclosed information regarding distributions of Class C Preferred PIK Units made to Stonepeak Catarina Holdings LLC following the effective date of the Exchange, consisting of 939,327 Class C Preferred PIK Units issued on August 30, 2019, 1,007,820 Class C Preferred PIK Units issued on November 29, 2019 and 1,039,314 Class C Preferred PIK Units issued on February 28, 2020. The number of common units disclosed in the Schedule 13D/A includes 6,183,182 common units that the Stonepeak Beneficial Owners currently have the right to acquire within the next 60 days upon exercise of the Warrant held by Stonepeak Catarina, such common units are not included for any other person on this table in accordance with Rule 13d-3(d)(1)(i) under the Exchange Act. This amount also includes 4,509,792 common units held directly by SPCE Sub, SPCE Sub may be deemed the beneficial owner of such units. The principal business address of each reporting person in the Schedule 13D/A is 55 Hudson Yards, 550 W. 34th St., 48th Floor, New York, NY 10001. The Schedule 13D/A filing lists each filing person as having shared voting and dispositive power over the common units and the Class C Preferred Units.

(3) Ownership data as reported on Schedule 13D filed on November 28, 2016 by SN UR Holdings, LLC and Mesquite. The principal business address of each filing reporting person is 1000 Main Street, Suite 3000, Houston, Texas 77002. The filing lists each filing person as having shared voting and dispositive power over the common units.

(4) Ownership data as reported on a Schedule 13G/A filing dated February 12, 2021 by Invesco Ltd. The principle business address of the reporting person is 1555 Peachtree Street NE, Suite 1800, Atlanta, GA 30309. The filing lists the reporting person as having sole voting and dispositive power over the common units.

(5) Of these common units, 1,000 are held by Mr. Bigman's minor children.

Equity Compensation Plan Information

The following table reflects our equity compensation plan information for our only equity compensation plan, the Sanchez Production Partners LP Long-Term Incentive Plan, as of December 31, 2020:

	Number of Securities to be issued upon exercise of outstanding options, warrants, and rights	Weighted-average exercise price of outstanding options, warrants, and rights	Number of securities remaining available for future issuance under equity compensation plans
Plan Category			
Equity compensation plans approved by security holders	—	$ —	974,393
Equity compensation plans not approved by security holders	—	—	—
Total	—	$ —	974,393

Item 13. Certain Relationship and Related Transaction and Director Independence

Relationship with Stonepeak

Since October 14, 2015, Stonepeak Catarina has owned all of our issued and outstanding preferred units.

As of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) the Warrant that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights. Stonepeak also owns 100% of the issued and outstanding equity interests in SP Holdings, which is the sole member of our general partner. SP Holdings has the right to appoint all of the members of the Board of directors other than two directors which Stonepeak Catarina is entitled to designate pursuant to that certain Amended and Restated Board Representation and Standstill Agreement, dated as of August 2, 2019. Stonepeak controls us and our general partner and has the ability to appoint all of the members of the Board and is considered a related party of the Partnership.

Currently, four of our directors, Jack Howell, Luke Taylor, Michael Bricker and John T. Steen III are representatives of Stonepeak, as either employees or operating partners of Stonepeak. Messrs. Howell, Taylor, Bricker and Steen do not receive separate compensation for their service on the Board, but they are entitled to indemnification related to their service as directors pursuant to the terms of our partnership agreement. “See Part III, Item 11. Executive Compensation—Compensation of Directors.”

Relationship with Mesquite

Prior to emergence from the Mesquite Chapter 11 Case, Mesquite was considered a related party of the Partnership because (i) Antonio R. Sanchez, III, who served as the Chairman of the Board at such time, also served as the Chief Executive Officer of Mesquite, (ii) Patricio D. Sanchez, who served as a member of the Board and as our President and Chief Operating Officer at such time, also served as a senior vice president and Chief Operating Officer of Mesquite, and (iii) Mesquite and certain other members of the Sanchez family directly or indirectly owned approximately 24.3% of the issued and outstanding common units of the Partnership at such time. As of June 30, 2020, Mesquite is not considered a related party of the Partnership. Prior to the date of this Form 10-K, Antonio R. Sanchez, III resigned from his position as a member of the Board and the Chairman of the Board and Patricio D. Sanchez resigned from his position as a member of the Board and as our President and Chief Operating Officer.

Relationship with SP Holdings

We are controlled by our general partner, Evolve Transition Infrastructure GP LLC. The sole member of our general partner is SP Holdings which has no officers. The sole member of SP Holdings is Stonepeak Catarina and the managing member of SP Holdings is Stonepeak Catarina Upper Holdings, LLC, an affiliate of Stonepeak Catarina.

Shared Services Agreement

We have entered into the Shared Services Agreement with SP Holdings. In connection with providing the services under the Shared Services Agreement, SP Holdings receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Prior to August 2, 2019 each of these fees, not including the reimbursement of costs, was paid in cash unless SP Holdings elected for such fee to be paid in our equity. However, on August 2, 2019, we and SP Holdings entered into a letter agreement providing that until such time as we redeem all of our issued and outstanding Class C Preferred Units, SP Holdings will elect to receive its fees, not including reimbursement of costs, in common units rather than cash. In addition, on November 8, 2019, we and SP Holdings entered into an additional letter agreement providing that during the period beginning with the fiscal quarter ended September 30, 2019 and continuing until the end of the fiscal quarter after the fiscal quarter in which we redeem all of our issued and outstanding Class C Preferred Units (the "Tolling Period"), SP Holdings would agree to delay receipt of its fees, not including reimbursement of costs. During the Tolling Period, we are required to keep an accurate ledger of the dollar amount of the fee applicable to each quarter within the Tolling Period and the daily closing price of our common units on the NYSE. Following the end of the Tolling Period we will provide a notice to SP Holdings including such ledgers and pay the accrued fees within thirty days of delivery of such notice. The Shared Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless we or SP Holdings provide notice of termination to the other with at least 180 days' notice. For the fees earned during the year ended December 31, 2020, pursuant to the November 8, 2019 letter agreement, SP Holdings did not receive any fees, other than reimbursement of its costs. However, pursuant to the requirements under the November 8, 2019 letter agreement, we have determined that the fees earned during the years ended December 31, 2020 and 2019 are approximately $7.2 million and $7.3 million, respectively.

The Shared Services Agreement can be terminated (i) by either party at any time by 180 days' prior written notice to the other party, (ii) by SP Holdings if there is an uncured material breach thereunder by the Partnership, or (iii) by the Partnership, subject to Board approval, if (1) there is an uncured material breach thereunder by SP Holdings or (2) there is a change in control of SP Holdings. Pursuant to the Standstill Agreement, the Partnership must obtain Stonepeak Catarina's consent to its termination of the Shared Services Agreement. The Shared Services Agreement provides that if there is a termination other than by either party at the end of the Service Agreement's term, by the Partnership for an uncured breach by SP Holdings, or by the Partnership upon a change of control of SP Holdings, then the Partnership will owe a termination payment to SP Holdings in an amount equal to $5,000,000 plus 5% of the transaction value of all asset acquisitions theretofore consummated. We estimate that this amount was in excess of $35.0 million as of December 31, 2020. Such termination fee may be payable in cash or common units. If the Partnership terminates upon 180 days' prior notice then the Partnership must also pay to SP Holdings all costs and expenses of SP Holdings that result from such termination. To date, no notice of termination of the Shared Services Agreement has been delivered by SP Holdings, and the Partnership is continuing to discuss the Shared Services Agreement with SP Holdings.

Related Party Transactions

2019

Class C Preferred Unit Issuance and Warrant

On August 2, 2019, Stonepeak Catarina exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and a warrant exercisable for junior securities (the "Warrant") in a privately negotiated transaction (the "Exchange"). In connection with the Exchange, the Partnership entered into (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended Partnership Agreement) to set forth the terms of the Class C Preferred Units, (ii) the Amended and Restated Registration Rights Agreement with

Stonepeak relating to the registered resale of common units issuable upon the exercise of the Warrant, and (iii) the Amended and Restated Board Representation and Standstill Agreement with Stonepeak. In addition, on August 2, 2019, the Partnership's general partner entered into Amendment No. 3 to its Limited Liability Company Agreement to provide certain changes necessary in connection with the Exchange.

On August 2, 2019, in connection with the Exchange, Stonepeak Catarina received the Warrant. The Warrant may be exercised at any time and from time to time during the period beginning on August 2, 2019 and ending on the later of the seventh anniversary of such date and the date thirty days after the date on which all of the Class C Preferred Units have been redeemed for a number of Junior Securities (as such term is defined in the Warrant) equal to 10% of each applicable class of Junior Securities deemed outstanding as of the exercise date. No exercise price will be payable in connection with the exercise of the Warrant.

At the time of the Exchange and Warrant, Stonepeak Catarina owned all of the Partnership's issued and outstanding Class B Preferred Units and 393,291 common units, representing an approximately 61.7% interest in the Partnership. Jack Howell and Luke Taylor, members of the Board during the year ended December 31, 2019, were also employees of Stonepeak at the time of the Exchange.

2020

Settlement Agreement

On June 6, 2020 the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement with Mesquite and certain of its subsidiaries. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, including but not limited to, (i) Amendment No. 2, (ii) the Seco Catarina Agreement, and (iii) the Seco Comanche Agreement. Each such agreement will become effective only upon satisfaction of certain closing conditions described in the Settlement Agreement.

JT3 Consulting Agreement

On June 30, 2020, our general partner entered into that certain Consultancy Agreement (the "JT3 Consulting Agreement") with JT3 Advisors LLC ("JT3 Advisors"). JT3 Advisors is an entity owned by John T Steen III, who has served as the Chairman of the Board since September 2020. Pursuant to the terms of the JT3 Consulting Agreement the Partnership pays JT3 Advisors a consulting fee of $20,000 per month for the provision of services to aid the Partnership in achieving its commercial goals, including analysis and assessment of potential commercial arrangements and recommendation of selected arrangements to our management. The JT3 Consulting Agreement was terminated in March 2021. Consulting fees earned under the JT3 Consulting Agreement were approximately $200,000.

Certain Transactions with Stonepeak

On November 16, 2020, the Partnership and Stonepeak Catarina entered the Stonepeak Letter Agreement wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The Stonepeak Letter Agreement also provides that Stonepeak Catarina will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the end of such quarter. The Letter Agreement Transactions were referred to the Conflicts Committee of the Board. The Conflicts Committee approved the Letter Agreement Transactions, recommended that the Board approve and authorize the execution and performance of the Letter Agreement Transactions, and verified that their approvals constituted "Special Approval" of the Letter Agreement Transactions under and pursuant to our partnership agreement. Following the approval and recommendation from the Conflicts Committee, the Board approved the Letter Agreement Transactions. An aggregate distribution of 22,274,869 common units was made to Stonepeak Catarina on February 1, 2021, following the satisfaction of certain issuance conditions. The approximate value of this transaction was $12.9 million.

On January 28, 2021, Stonepeak Catarina provided us with its notice of election to receive a Common Unit PIK Distribution for the fourth quarter of 2020. The aggregate distribution of 12,445,491 common units was made to Stonepeak

Catarina on February 25, 2021, following the satisfaction of certain issuance conditions. The approximate value of this transaction was $12.9 million.

As a result of the foregoing transactions, as of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) the Warrant that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights.

Pursuant to Section 15.1 of our partnership agreement, if at any time Stonepeak holds more than 80% of our outstanding common units and completes the Stonepeak LCR Transfer, Stonepeak will be able to cause our general partner or a controlled affiliate of our general partner to exercise the limited call right. Stonepeak would effect any such exercise by first completing the Stonepeak LCR Transfer and then causing our general partner to exercise its limited call right at a price equal to the greater of (1) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the limited call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its controlled affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Common unitholders may also incur tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of common units to be repurchased upon exercise of the limited call right. Furthermore, there is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units, including common units issued pursuant to the Stonepeak Letter Agreement or as a result of the termination or renegotiation of the Shared Services Agreement, and then exercising its limited call right. If our general partner exercises its limited call right, the effect would be to take the Partnership private and, if the common units are subsequently deregistered, the Partnership will no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended. As of March 16, 2021, the General Partner and its controlled affiliates do not own any Common Units.

Director Independence

See “Part III, Item 10. Directors, Executive Officers, and Corporate Governance” for information regarding director independence.

Item 14. Principal Accounting Fees and Services

We engaged our principal accountant, KPMG LLP (“KPMG”), to audit our financial statements and perform other professional services for the fiscal years ended December 31, 2020 and 2019.

Audit Fees. The aggregate fees billed for the financial statement audit or services provided in connection with statutory or regulatory filings for the years ended December 31, 2020 and 2019 were $932,857 and $978,885, respectively.

Audit-Related Fees. There were no audit-related fees billed by KPMG for the years ended December 31, 2020 and 2019.

Tax Fees. There were no tax fees billed by KPMG for the years ended December 31, 2020 and 2019.

All Other Fees. There were no other fees billed by KPMG for the years ended December 31, 2020 and 2019.

Audit Committee Pre-Approval Policies and Practices

The Audit Committee must pre-approve any audit and permissible non-audit services performed by our independent registered public accounting firm. In addition, the Audit Committee has oversight responsibility to ensure that the independent registered public accounting firm is not engaged to perform certain enumerated non-audit services, including, but not limited to, bookkeeping, financial information system design and implementation, appraisal or valuation services, internal audit outsourcing services and legal services. The Audit Committee has adopted an audit and non-audit services pre-approval policy, which sets forth the procedures and the conditions pursuant to which services proposed to be performed by the independent registered public accounting firm must be approved. Pursuant to the policy, all services must be reviewed and approved and the chairman of the Audit Committee has been delegated the authority to specifically pre-approve services, which pre-approval is subsequently reviewed with the committee. All of the services described as Audit Fees, Audit-Related Fees, Tax Fees and All Other Fees were approved by the Audit Committee.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as a part of this Form 10-K:

1. Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

2. Financial Statement Schedules:

None.

3. Exhibits Required by Item 601 of Regulation S-K.

The exhibits required by Item 601 of Regulation S-K are listed in subparagraph (b) below.

(b) The following exhibits are filed or furnished with this Form 10-K or incorporated by reference:

Exhibit Number	Description
2.1	Contribution Agreement, dated as of August 9, 2013, by and between Constellation Energy Partners LLC and Sanchez Energy Partners I, LP (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K field by Constellation Energy Partners LLC on August 9, 2013, File No. 001-33147).
2.2	Purchase and Sale Agreement, dated as of March 31, 2015, between SEP Holdings III, LLC, Sanchez Production Partners LP and SEP Holdings IV, LLC (incorporated herein by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 1, 2015, File No. 001-33147).
2.3	Purchase and Sale Agreement, dated as of September 25, 2015, by and among Sanchez Energy Corporation, SN Catarina, LLC and Sanchez Production Partners LP (incorporated herein by reference to Exhibit 2.1 the Current Report on Form 8-K filed by Sanchez Production Partners LP on September 29, 2015, File No. 001-33147).
2.4	Purchase and Sale Agreement by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP, dated July 5, 2016 (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on August 12, 2016, File No. 001-33147).
2.5	Purchase and Sale Agreement, dated October 6, 2016, by and among Sanchez Energy Corporation, SN Midstream, LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 7, 2016, File No. 001-33147).
2.6	Purchase and Sale Agreement, dated October 6, 2016, by and among SN Cotulla Assets, LLC, SN Palmetto, LLC, SEP Holdings IV, LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 7, 2016, File No. 001-33147).
2.7	Purchase and Sale Agreement, dated October 6, 2016, by and among Sanchez Energy Corporation, SN Terminal, LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 2.3 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 7, 2016, File No. 001-33147).

2.8	Membership Interest Purchase and Sale Agreement, dated May 10, 2017, between Sanchez Midstream Partners LP (f/k/a Sanchez Production Partners LP) and Exponent Energy, LLC (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
2.9	Purchase and Sale Agreement, dated June 30, 2017, between SEP Holdings IV, LLC and Sendero Petroleum, LLC (incorporated by reference to Exhibit 2.2 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
2.10	Amendment No. 1 to Purchase and Sale Agreement, dated July 31, 2017, between SEP Holdings IV, LLC and Sendero Petroleum, LLC (incorporated by reference to Exhibit 2.3 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
2.11	Purchase and Sale Agreement between Sanchez Midstream Partners LP and Dallas Petroleum Group, LLC dated October 12, 2017 (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on November 14, 2017, File No. 001-33147).
2.12	Agreement to Purchase Oil and Gas Interests between SEP Holdings IV, LLC and EP Energy E&P Company, L.P., dated April 30, 2018 (incorporated herein by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on May 10, 2018, File No. 001-33147).
3.1	Certificate of Conversion of Sanchez Production Partners LLC (incorporated herein by reference to Exhibit 4.1 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
3.2	Certificate of Limited Partnership of Sanchez Production Partners LP (incorporated herein by reference to Exhibit 4.2 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
3.3	Certificate of Amendment to Certificate of Limited Partnership of Sanchez Production Partners LP (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on June 2, 2017, File No. 001-33147).
3.4	Certificate of Amendment to Certificate of Limited Partnership of Sanchez Midstream Partners LP (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Evolve Transition Infrastructure LP on February 26, 2021, File No. 001-33147).
3.5	Third Amended and Restated Agreement of Limited Partnership of Sanchez Production Partners LP (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
3.6	Letter Agreement, dated November 16, 2020, by and between Sanchez Midstream Partners LP, Sanchez Midstream Partners GP LLC and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on November 16, 2020, File No. 001-33147).
3.7	Amendment No. 1 to Third Amended and Restated Agreement of Limited Partnership of Sanchez Production Partners LP (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K filed by Evolve Transition Infrastructure LP on February 26, 2021, File No. 001-33147).
3.8	Certificate of Formation of Sanchez Production Partners GP LLC (incorporated by reference to Exhibit 4.4 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).

3.9	Certificate of Amendment to Certificate of Formation of Sanchez Midstream Partners GP LLC (incorporated herein by reference to Exhibit 3.3 to the Current Report on Form 8-K filed by Evolve Transition Infrastructure LP on February 26, 2021, File No. 001-33147).
3.10	Limited Liability Company Agreement of Sanchez Production Partners GP LLC (incorporated herein by reference to Exhibit 4.5 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
3.11	Amendment No. 1 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC (incorporated herein by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q/A filed by Sanchez Production Partners LP on September 3, 2015, File No. 001-33147).
3.12	Amendment No. 2 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
3.13	Amendment No. 3 to Limited Liability Company Agreement of Sanchez Production Partners GP LLC, dated August 2, 2019 (incorporated herein by reference to Exhibit 3.2 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on August 5, 2019, File No. 001-33147).
3.14	Amendment No. 4 to Limited Liability Company Agreement of Sanchez Midstream Partners GP LLC, dated September 7, 2020 (incorporated herein by reference to Exhibit 3.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on September 9, 2020, File No. 001-33147).
3.15	Amendment No. 5 to Limited Liability Company Agreement of Sanchez Midstream Partners GP LLC, dated September 7, 2020 (incorporated herein by reference to Exhibit 3.4 to the Current Report on Form 8-K filed by Evolve Transition Infrastructure LP on February 26, 2021, File No. 001-33147).
4.1	Registration Rights Agreement, dated November 22, 2016, between Sanchez Production Partners LP and SN UR Holdings, LLC (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on November 22, 2016, File No. 001-33147).
4.2	Amended and Restated Registration Rights Agreement, dated August 2, 2019, by and among Sanchez Midstream Partners LP and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 4.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
4.3*	Description of Registrant Securities.
10.1	Purchase Agreement, dated November 16, 2016, between Sanchez Production Partners LP and SN UR Holdings, LLC (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on November 22, 2016, File No. 001-33147).
10.2	Third Amended and Restated Credit Agreement, dated as of March 31, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on April 1, 2015, File No. 001-33147).
10.3	Amendment and Waiver of Third Amended and Restated Credit Agreement, dated as of August 12, 2015, between Sanchez Production Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on August 14, 2015, File No. 001-33147).

10.4	Joinder, Assignment and Second Amendment to Third Amended and Restated Credit Agreement, dated as of October 14, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
10.5	Third Amendment to Third Amended and Restated Credit Agreement, dated as of November 12, 2015, among Sanchez Production Partners LP, Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on November 13, 2015, File No. 001-33147).
10.6	Fourth Amendment to Third Amended and Restated Credit Agreement among Sanchez Production Partners LP, the guarantors party thereto, each of the lenders party thereto, and Royal Bank of Canada, as administrative agent and collateral agent, dated July 5, 2016 (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on August 12, 2016, File No. 001-33147).
10.7	Fifth Amendment to the Third Amended and Restated Credit Agreement dated as of April 17, 2017, between Sanchez Production Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on May 15, 2017, File No. 001-33147).
10.8	Sixth Amendment to the Third Amended and Restated Credit Agreement dated as of November 7, 2017, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on November 14, 2017, File No. 001-33147).
10.9	Seventh Amendment to the Third Amended and Restated Credit Agreement dated as of February 5, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.11 to the Annual Report on Form 10-K filed by Sanchez Midstream Partners LP on March 12, 2018, File No. 001-33147).
10.10	Eighth Amendment to the Third Amended and Restated Credit Agreement dated as of May 7, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on May 10, 2018, File No. 001-33147).
10.11	Ninth Amendment to the Third Amended and Restated Credit Agreement dated as of May 7, 2018, between Sanchez Midstream Partners LP, the Lenders party thereto and Royal Bank of Canada as Administrative Agent and as Collateral Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on November 25, 2019, File No. 001-33147).
10.12	Tenth Amendment to Third Amended and Restated Credit Agreement dated as of November 6, 2020, between Sanchez Midstream Partners LP, the lenders party thereto and Royal Bank of Canada, as Administrative Agent and as Collateral Agent (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on November 9, 2020, File No. 001-33147).
10.13*	Summary Compensation of Executive Officers of Evolve Transition Infrastructure Partners GP LLC.
10.14*	Summary Compensation of Directors of Evolve Transition Infrastructure GP LLC.

10.15	Amended and Restated Shared Services Agreement, dated as of March 6, 2015, between SP Holdings, LLC and Sanchez Production Partners LP (incorporated herein by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Production Partners LP on May 15, 2015, File No. 001-33147).
10.16	Contract Operating Agreement, dated May 8, 2014, between Constellation Energy Partners LLC and Sanchez Oil & Gas Corporation (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Constellation Energy Partners LLC on May 8, 2014, File No. 001-33147).
10.17	Geophysical Seismic Data Use License Agreement, dated as of September 7, 2020, by and among Sanchez Oil & Gas Corporation, Sanchez Midstream Partners LP, Sanchez Midstream Partners GP LLC and SEP Holdings IV, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on September 9, 2020, File No. 001-33147).
10.18	Firm Gathering and Processing Agreement, dated as of October 14, 2015, by and between Catarina Midstream, LLC and SN Catarina, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on October 14, 2015, File No. 001-33147).
10.19	Amendment No. 1 to Firm Gathering and Processing Agreement by and between SN Catarina, LLC and Catarina Midstream, LLC, dated June 30, 2017 (incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed by Sanchez Midstream Partners LP on August 14, 2017, File No. 001-33147).
10.20**	Amendment No. 2 to Firm Gathering and Processing Agreement, dated as of June 30, 2020, by and between SN Catarina, LLC and Catarina Midstream, LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on July 7, 2020, File No. 001-33147).
10.21+	Sanchez Production Partners LP Long-Term Incentive Plan (incorporated herein by reference to Exhibit 4.6 to the Post-Effective Amendment No. 1 to the Registration Statement on Form S-4 filed by Sanchez Production Partners LP on March 6, 2015, File No. 333-198440).
10.22+	Form of Award Agreement Relating to Restricted Units (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on December 3, 2015, File No. 001-33147).
10.23+	Form of Award Agreement Relating to Restricted Units (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on March 28, 2017, File No. 001-33147).
10.24	Settlement Agreement and Release, effective January 25, 2017, by and between Stonepeak Catarina Holdings LLC and Sanchez Production Partners LP (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Production Partners LP on January 27, 2017, File No. 001-33147).
10.25+	Form of Award Agreement Relating to Restricted Units incorporated by reference to Exhibit 10.24 to the Annual Report on Form 10-K filed by Sanchez Midstream Partners LP on March 7, 2019, File No. 001-33147.
10.26	Amended and Restated Board Representation and Standstill Agreement, dated August 2, 2019, by and among Sanchez Midstream Partners LP, Sanchez Midstream Partners GP LLC and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).

10.27*+	Executive Services Agreement, dated as of August 2, 2019, by and between Charles C. Ward and Sanchez Midstream Partners GP LLC.
10.28*+	Executive Services Agreement, dated as of August 2, 2019, by and between Gerald F. Willinger and Sanchez Midstream Partners GP LLC.
10.29	Warrant Exercisable for Junior Securities, dated August 2, 2019, by and between Sanchez Midstream Partners LP and Stonepeak Catarina Holdings LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on August 5, 2019, File No. 001-33147).
10.30*	Amendment No. 1 to Warrant Exercisable for Junior Securities, dated February 24, 2021, by and between Sanchez Midstream Partners LP and Stonepeak Catarina Holdings LLC.
10.31**	Settlement Agreement, dated as of June 6, 2020, by and among Sanchez Energy Corporation, SN Palmetto, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, Rockin L Ranch Company, LLC, SN Payables, LLC, SN EF Maverick, LLC and SN UR Holdings, LLC, Catarina Midstream, LLC, Carnero G&P LLC, Seco Pipeline, LLC, Sanchez Midstream Partners LP, Sanchez Midstream Partners GP, LLC, SP Holdings, LLC, and TPL SouthTex Processing Company LP. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on June 11, 2020, File No. 001-33147).
10.32**	Amendment Agreement, dated as of June 14, 2020, by and among Sanchez Energy Corporation, SN Palmetto, LLC, SN Marquis LLC, SN Cotulla Assets, LLC, SN Operating, LLC, SN TMS, LLC, SN Catarina, LLC, Rockin L Ranch Company, LLC, SN Payables, LLC, SN EF Maverick, LLC, SN UR Holdings, LLC, Catarina Midstream, LLC, Carnero G&P LLC, Seco Pipeline, LLC, Sanchez Midstream Partners LP, Sanchez Midstream Partners GP, LLC, SP Holdings, LLC, and TPL SouthTex Processing Company LP. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on June 18, 2020, File No. 001-33147).
10.33**	Firm Transportation Service Agreement, dated as of June 30, 2020, by and between Seco Pipeline, LLC and SN Catarina, LLC (incorporated herein by reference to Exhibit 10.2 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on July 7, 2020, File No. 001-33147).
10.34**	Firm Transportation Service Agreement, dated as of June 30, 2020, by and between Seco Pipeline, LLC and SN EF Maverick, LLC (incorporated herein by reference to Exhibit 10.3 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on July 7, 2020, File No. 001-33147).
10.35*+	Award Letter Agreement, dated March 13, 2020, by and between Gerald F. Willinger and Sanchez Midstream Partners GP LLC.
10.36*+	Award Letter Agreement, dated March 13, 2020, by and between Charles C. Ward and Sanchez Midstream Partners GP LLC.
10.37	Full and Final Settlement and Release Agreement, dated as of December 23, 2020, by and among Dimension Energy Services, LLC, Sunbelt Tractor & Equipment Company, Sanchez Oil and Gas Corporation, Mesquite Energy, Inc., f/k/a Sanchez Energy Corporation, Sanchez Midstream Partners LP, Seco Pipeline LLC and Sanchez Midstream Partners GP LLC (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed by Sanchez Midstream Partners LP on December 30, 2020, File No. 001-33147).
21.1*	List of subsidiaries of Evolve Transition Infrastructure LP.
23.1*	Consent of KPMG LLP.

23.2*	Consent of Ryder Scott Co. LP.
31.1*	Certification of Chief Executive Officer of Evolve Transition Infrastructure GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer and Secretary of Evolve Transition Infrastructure GP LLC pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification of Chief Executive Officer of Evolve Transition Infrastructure GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2*	Certification of Chief Financial Officer and Secretary of Evolve Transition Infrastructure GP LLC pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Ryder Scott Co. LP.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document

* Filed herewith
** Certain portions of this exhibit (indicated by "[***]") have been omitted pursuant to Item 601(b)(10) of Regulation S-K.

\+ Management contract or compensatory plan or arrangement.

Item 16. Form 10-K Summary

None.

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.

Evolve Transition Infrastructure LP

By: Evolve Transition Infrastructure GP LLC, its general partner

Date: March 16, 2021

By /s/ Gerald F. Willinger
Name **Gerald F. Willinger**
Title **Chief Executive Officer**

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below, constitutes and appoints Gerald F. Willinger and Charles C. Ward, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents full power and authority to do and perform each and every act and thing requisite or necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

This report has been signed below by the following persons on behalf of the general partner of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gerald F. Willinger **Gerald F. Willinger**	Director; Chief Executive Officer (Principal Executive Officer)	March 16, 2021
/s/ Charles C. Ward **Charles C. Ward**	Chief Financial Officer & Secretary (Principal Financial Officer)	March 16, 2021
/s/ John T. Steen III **John T. Steen III**	Director; Chairman of the Board	March 16, 2021
/s/ Alan S. Bigman **Alan S. Bigman**	Director	March 16, 2021
/s/ Michael Bricker **Michael Bricker**	Director	March 16, 2021
/s/ Jack Howell **Jack Howell**	Director	March 16, 2021
/s/ Richard S. Langdon **Richard S. Langdon**	Director	March 16, 2021
/s/ Steven E. Meisel **Steven E. Meisel**	Director	March 16, 2021
/s/ Luke R. Taylor **Luke R. Taylor**	Director	March 16, 2021

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Partners of Evolve Transition Infrastructure LP and the Board of Directors of Evolve Transition Infrastructure GP LLC
Evolve Transition Infrastructure LP:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Evolve Transition Infrastructure LP and subsidiaries (the Partnership) as of December 31, 2020 and 2019, the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2020, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the years in the two-year period ended December 31, 2020, in conformity with U.S. generally accepted accounting principles.

Going Concern

The accompanying consolidated financial statements have been prepared assuming that the Partnership will continue as a going concern. As discussed in Note 2 to the consolidated financial statements, the Partnership's inability to generate sufficient liquidity to meet future debt obligations raises substantial doubt about its ability to continue as a going concern. Management's plans in regard to these matters are also described in Note 2. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These consolidated financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (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 consolidated financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated 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 consolidated 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 consolidated 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 consolidated 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 consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated 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.

Evaluation of the proved oil and natural gas properties for impairment

As discussed in Notes 2 and 7 to the consolidated financial statements, the Partnership reviews oil and natural gas properties for impairment on a field-by-field basis when facts and circumstances indicate that their carrying value may not be recoverable. The Partnership assesses impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates for the impairment testing are based on third-party reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Other inputs, besides reserves, used to determine the fair values of proved properties include estimates of: (i) future operating and development costs; (ii) future commodity prices; and (iii) a market-based weighted average cost of capital rate. The Partnership recorded an impairment of $23.4 million related to proved oil and natural gas properties.

We identified the evaluation of the proved oil and natural gas properties for impairment as a critical audit matter. Specifically, there was a high degree of subjective auditor judgment involved in evaluating the key assumptions used to assess the Partnership's proved oil and gas properties for impairment. The key assumptions were the estimated future production used in estimating proved oil and gas reserves and the risk adjusted discount rate assumption used to estimate the future net cash flows of proved oil and natural gas properties. In addition, changes to these key assumptions could have a significant impact on the assessment of proved oil and natural gas properties for impairment.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design of an internal control over the Partnership's process to determine the risk adjusted discount rate assumption. We evaluated (1) the professional qualifications of the Partnership's internal reserve engineer as well as the external reserve engineers and external engineering firm, (2) the knowledge, skills, and ability of the Partnership's internal and external reserve engineers, and (3) the relationship of the external reserve engineers and external engineering firm to the Partnership. We compared the forecasted production used by the Partnership to historical production rates and read and considered the report of the external reserve engineers in connection with our evaluation of the Partnership's reserve estimates. We evaluated the risk adjusted discount rate against underlying documentation used by the Partnership and guideline ranges from published industry surveys. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the risk adjusted discount rate by comparing it against a discount rate that was independently developed using publicly available market data for comparable entities.

/s/ KPMG LLP

We have served as the Partnership's auditor since 2013.

Houston, Texas
March 16, 2021

EVOLVE TRANSITION INFRASTRUCTURE LP and SUBSIDIARIES
Consolidated Statements of Operations
(In thousands, except unit data)

	Years Ended December 31,	
	2020	**2019**
Revenues		
Natural gas sales	$ 427	$ 683
Oil sales	10,856	9,512
Natural gas liquid sales	254	539
Gathering and transportation sales	785	6,825
Gathering and transportation lease revenues	44,671	59,090
Total revenues	56,993	76,649
Expenses		
Operating expenses		
Lease operating expenses	6,224	7,378
Transportation operating expenses	9,314	11,553
Production taxes	311	621
General and administrative expenses	18,296	17,610
Unit-based compensation expense	2,602	1,351
Depreciation, depletion and amortization	22,873	25,333
Asset impairments	24,222	32,119
Accretion expense	567	526
Total operating expenses	84,409	96,491
Other (income) expense		
Interest expense, net	95,871	39,789
Earnings from equity investments	(4,479)	(2,831)
Other income	(71)	(5,860)
Total other expenses	91,321	31,098
Total expenses	175,730	127,589
Loss before income taxes	(118,737)	(50,940)
Income tax expense	24	202
Net loss	(118,761)	(51,142)
Less		
Preferred unit paid-in-kind distributions	—	(14,409)
Preferred unit distributions	—	(8,838)
Preferred unit amortization	—	(1,708)
Deemed distribution	—	103,773
Net income (loss) attributable to common unitholders - Basic	(118,761)	27,676
Mark-to-market on warrant	—	(3,244)
Net income (loss) attributable to common unitholders - Diluted	$ (118,761)	$ 24,432
Net income (loss) per unit		
Common units - Basic	$ (5.94)	$ 1.46
Common units - Diluted	$ (5.94)	$ 1.23
Weighted Average Units Outstanding		
Common units - Basic	19,978,633	18,939,145
Common units - Diluted	19,978,633	19,810,679

See accompanying notes to consolidated financial statements.

EVOLVE TRANSITION INFRASTRUCTURE LP and SUBSIDIARIES
Consolidated Balance Sheets
(In thousands, except unit data)

	December 31, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,718	$ 5,099
Accounts receivable	6,670	133
Accounts receivable - related entities	—	6,719
Prepaid expenses	595	1,193
Fair value of commodity derivative instruments	—	226
Total current assets	8,983	13,370
Oil and natural gas properties and related equipment		
Oil and natural gas properties, equipment and facilities (successful efforts method)	112,471	112,476
Gathering and transportation assets	187,977	186,941
Less: accumulated depreciation, depletion, amortization and impairment	(177,553)	(144,189)
Oil and natural gas properties and equipment, net	122,895	155,228
Other assets		
Intangible assets, net	131,786	145,246
Equity investments	89,635	100,311
Other non-current assets	129	285
Total assets	$ 353,428	$ 414,440
LIABILITIES AND PARTNERS' CAPITAL		
Current liabilities		
Accounts payable and accrued liabilities	$ 4,420	$ 5,347
Accounts payable and accrued liabilities - related entities	25,737	631
Royalties payable	359	359
Short-term debt, net of debt issuance costs	110,233	39,374
Class C preferred units	345,205	—
Fair value of commodity derivative instruments	—	985
Total current liabilities	485,954	46,696
Other liabilities		
Long term accrued liabilities - related entities	12,137	4,892
Asset retirement obligation	7,465	6,898
Long-term debt, net of debt issuance costs	—	109,437
Class C preferred units	—	281,688
Other liabilities	1,416	629
Total other liabilities	21,018	403,544
Total liabilities	506,972	450,240
Commitments and contingencies (See Note 12)		
Partners' deficit		
Common units, 19,953,880 and 20,087,462 units issued and outstanding as of December 31, 2020 and 2019, respectively	(153,544)	(35,800)
Total partners' deficit	(153,544)	(35,800)
Total liabilities and partners' capital	$ 353,428	$ 414,440

See accompanying notes to consolidated financial statements.

EVOLVE TRANSITION INFRASTRUCTURE LP and SUBSIDIARIES
Consolidated Statements of Cash Flows
(In thousands)

	Years Ended December 31,	
	2020	**2019**
Cash flows from operating activities:		
Net loss	$ (118,761)	$ (51,142)
Adjustments to reconcile net loss to cash provided by operating activities:		
Depreciation, depletion and amortization	9,413	11,873
Amortization of debt issuance costs	767	1,266
Accretion of Class C discount	38,938	13,129
Class C distribution accrual	50,317	19,309
Asset impairments	24,222	32,119
Accretion expense	567	526
Distributions from equity investments	15,266	17,227
Equity earnings in affiliate	(4,479)	(2,831)
Mark-to-market on warrant	787	(3,244)
Net (gain) loss on commodity derivative contracts	(3,901)	3,772
Net cash settlements received on commodity derivative contracts	3,054	1,101
Unit-based compensation	2,602	1,351
Gain on earnout derivative	—	(5,856)
Amortization of intangible assets	13,460	13,460
Changes in Operating Assets and Liabilities:		
Accounts receivable	(6,499)	(6)
Accounts receivable - related entities	6,719	(23)
Prepaid expenses	598	(262)
Other assets	(115)	83
Accounts payable and accrued liabilities	(27,363)	6,378
Accounts payable and accrued liabilities- related entities	32,351	(122)
Other long-term liabilities	—	(123)
Net cash provided by operating activities	37,943	57,985
Cash flows from investing activities:		
Development of oil and natural gas properties	5	(131)
Construction of gathering and transportation assets	(1,832)	(1,063)
Contributions to equity affiliates	(111)	(242)
Net cash used in investing activities	(1,938)	(1,436)
Cash flows from financing activities:		
Payments for Class C Preferred Unit Exchange	—	(238)
Proceeds from issuance of debt	13,000	4,000
Repayment of debt	(52,000)	(34,000)
Distributions to common unitholders	—	(5,216)
Class B preferred unit cash distributions	—	(17,675)
Units tendered by SOG employees for tax withholdings	(41)	(218)
Debt issuance costs	(345)	(1,037)
Net cash used in financing activities	(39,386)	(54,384)
Net decrease in cash and cash equivalents	(3,381)	2,165
Cash and cash equivalents, beginning of period	5,099	2,934
Cash and cash equivalents, end of period	$ 1,718	$ 5,099
Supplemental disclosures of cash flow information:		
Change in accrued capital expenditures	$ 796	$ 528
Cash paid during the period for income taxes	$ 242	$ 138
Cash paid during the period for interest	$ 5,235	$ 9,159

See accompanying notes to consolidated financial statements.

EVOLVE TRANSITION INFRASTRUCTURE and SUBSIDIARIES
Consolidated Statements of Changes in Partners' Capital
(In thousands, except unit data)

	Common Units		Total
	Units	**Amount**	**Capital**
Partners' Deficit, December 31, 2018	16,486,239	$ (64,620)	$ (64,620)
Adoption of accounting standards	—	(181)	(181)
Preferred unit exchange	—	103,773	103,773
Unit-based compensation programs	1,109,880	1,531	1,531
Units tendered by SOG employees for tax withholdings	(85,417)	(218)	(218)
Common units issued for asset management fee	2,576,760	5,228	5,228
Cash distributions to common unitholders	—	(5,216)	(5,216)
Distributions - Class B Preferred Units	—	(24,955)	(24,955)
Net loss	—	(51,142)	(51,142)
Partners' Deficit, December 31, 2019	20,087,462	(35,800)	(35,800)
Unit-based compensation programs	(24,896)	1,058	1,058
Units tendered by SOG employees for tax withholdings	(108,686)	(41)	(41)
Net loss	—	(118,761)	(118,761)
Partners' Deficit, December 31, 2020	19,953,880	$ (153,544)	$ (153,544)

See accompanying notes to consolidated financial statements.

EVOLVE TRANSITION INFRASTRUCTURE and SUBSIDIARIES
Notes to Consolidated Financial Statements
December 31, 2020 and 2019

1. ORGANIZATION AND BUSINESS

Organization

We are a publicly-traded limited partnership formed in 2005 focused on the acquisition, development and ownership of infrastructure critical to the transition of energy supply to lower carbon sources. We own natural gas gathering systems, pipelines, and processing facilities in South Texas and continue to pursue energy transition infrastructure opportunities. Our common units are currently listed on the NYSE American under the symbol "SNMP."

On February 26, 2021, in connection with our management team's focus on expanding our business strategy to focus on the ongoing energy transition in the industries in which we operate, we changed our name to Evolve Transition Infrastructure LP and our general partner changed its name to Evolve Transition Infrastructure GP LLC.

2. BASIS OF PRESENTATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

Accounting policies used by us conform to accounting principles generally accepted in the United States of America ("GAAP). The accompanying financial statements include the accounts of us and our wholly-owned subsidiaries. All intercompany accounts and transactions have been eliminated in consolidation. Our business consists of two reportable segments: Production and Midstream. Midstream includes Western Catarina Midstream, the Carnero JV and Seco Pipeline. Production consists of our oil and natural gas properties in Texas and Louisiana. Our management evaluates performance based on these two business segments.

Recent Accounting Pronouncements

From time to time, new accounting pronouncements are issued by the Financial Accounting Standards Board ("FASB"), which are adopted by us as of the specified effective date. Unless otherwise discussed, management believes that the impact of recently issued standards, which are not effective, will not have a material impact on our consolidated financial statements upon adoption.

In January 2020, the FASB issued Accounting Standards Update ("ASU") 2020-01 "Investments – Equity Securities (Topic 321), Investments – Equity Method and Joint Ventures (Topic 323), and Derivatives and Hedging (Topic 815)," which clarifies the interaction among the accounting standards for equity securities, equity method investments and certain derivatives. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2020. We are currently in the process of evaluating the impact of adoption of this guidance on our condensed consolidated financial statements.

In August 2018, the FASB issued ASU 2018-13 "Fair Value Measurement (ASC 820): Disclosure Framework – Changes to the Disclosure Requirements for Fair Value Measurements," which modifies the disclosure requirements on fair value measurements. This ASU is effective for public business entities for annual and interim periods in fiscal years beginning after December 15, 2019. The adoption of this standard did not have a material impact on our consolidated financial statements.

In June 2016, the FASB issued ASU No. 2016-13, "Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments." This ASU modifies the impairment model to utilize an expected loss methodology in place of the currently used incurred loss methodology, which will result in more timely recognition of losses. Additionally, in November 2019, the FASB issued ASU 2019-10 "Financial Instruments – Credit Losses (Topic 326), Derivatives and Hedging (Topic 815), and Leases (Topic 842): Effective Dates," which changed the effective date for certain issuers to annual and interim periods in fiscal years beginning after December 15, 2022, and earlier adoption is permitted. We are currently in the process of evaluating the impact of adoption of this guidance on our consolidated financial statements.

Liquidity and Going Concern

The Partnership's inability to generate sufficient liquidity to meet future debt obligations raises substantial doubt regarding our ability to continue as a going concern. The Credit Agreement matures September 30, 2021 and our ability to continue as a going concern is contingent upon our ability to either (i) refinance or extend the maturity of the Credit Agreement, or (ii) obtain adequate new debt or equity financing to repay the Credit Agreement in full at maturity. We intend to refinance or extend the maturity of the Credit Agreement prior to its maturity date. However, we may not be able to refinance or extend the maturity of the Credit Agreement or, if we are able to refinance or extend the maturity, we may not be able to do so with borrowing and debt issue costs, terms, covenants, restrictions, commitment amount or a borrowing base favorable to us. The consolidated financial statements have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not include any adjustments that might result from the outcome of substantial doubt as to the Partnership's ability to continue as a going concern. If the Partnership cannot continue as a going concern, adjustments to the carrying values and classification of its assets and liabilities and the reported amounts of income and expenses could be required and could be material.

Use of Estimates

The consolidated financial statements are prepared in conformity with GAAP, which requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. These estimates and the underlying assumptions affect the amounts of assets and liabilities reported, disclosures about contingent assets and liabilities and reported amounts of revenues and expenses. The estimates that are particularly significant to our financial statements include our ability to continue as a going concern; our reserves of natural gas, NGLs and oil; future cash flows from oil and natural gas properties; depreciation, depletion and amortization; asset retirement obligations; certain revenues and operating expenses; fair values of derivatives; and fair values of assets and liabilities. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. These estimates and assumptions are based on management's best judgment using the data available. Management evaluates its estimates and assumptions on an on-going basis using historical experience and other factors, including the current economic environment, which management believes to be reasonable under the circumstances. Such estimates and assumptions are adjusted when facts and circumstances dictate. As future events and their effects cannot be determined with precision, actual results could differ from the estimates. Any changes in estimates resulting from continuing changes in the economic environment will be reflected in the financial statements in future periods.

Revenue Recognition

Midstream

We account for revenue from contracts with customers in accordance with ASC 606 and ASC 842 for our midstream segment. The Seco Pipeline Transportation Agreement is our only contract that we account for using ASC 606. Under the Seco Pipeline Transportation Agreement, we agreed to provide transportation services of certain quantities of natural gas from the receipt point to the delivery point. Each MMBtu of natural gas transported is distinct and the transportation services performed on each distinct molecule of product is substantially the same in nature. As such, we applied the series guidance and treat these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. Additionally, Seco Pipeline Transportation Agreement contains variable consideration in the form of volume variability. As the distinct goods or services (rather than the series) are considered for the purpose of allocating variable consideration, we have taken the optional exception under ASC 606. Under this exception, revenue is alternatively recognized in the period that control is transferred to the customer and the respective variable component of the total transaction price is resolved.

In October 2015, we acquired (the "Catarina Transaction") a gathering system from Mesquite ("Western Catarina Midstream"), which is located on the western portion of Mesquite's acreage position in Dimmit, La Salle and Webb counties in Texas. In conjunction with the Catarina Transaction, we entered into a 15-year firm gas gathering and processing agreement with Mesquite, pursuant to which Mesquite agreed to tender all of its crude oil, natural gas and other hydrocarbon-based product volumes on approximately 35,000 dedicated acres for processing and transportation through

Western Catarina Midstream, with the potential to tender additional volumes outside of the dedicated acreage (the "Gathering Agreement").

The Gathering Agreement was classified as an operating lease at inception and is accounted for under ASC 842, as Mesquite controls the physical use of the property under the lease. Revenues relating to the Gathering Agreement is recognized in the period service is provided. Under this arrangement, the Partnership receives a fee or fees for services provided. The revenue the Partnership recognizes from gathering and transportation services is generally directly related to the volume of oil and natural gas that flows through its systems.

Production

Our oil, natural gas, and NGL revenue is marketed and sold on our behalf by the respective asset operators. We are not party to the contracts with the third-party customers. However, we are party to joint operating agreements, which we account for under ASC 808, and revenues and expenses for these arrangements is recognized based on the information provided to us by the operators.

We additionally recognize and present changes in the fair value of our commodity derivative instruments within natural gas sales and oil sales in the consolidated statements of operations, which is accounted for under ASC 815, "Derivatives and Hedging".

Accounts Receivable, Net

Our accounts receivable are primarily from our contractual agreements with Mesquite and its subsidiaries, operators of our oil and natural gas properties and counterparties to our financial instruments. Oil receivables are generally collected within 30 days after the end of the month. Natural gas receivables are generally collected within 60 days after the end of the month. We review all outstanding accounts receivable balances and record a reserve for amounts that we expect will not be fully recovered. Actual balances are not applied against the reserves until substantially all collection efforts have been exhausted. Our allowance for doubtful accounts was $0.4 million as of December 31, 2020 and 2019.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject us to a concentration of credit risk consist of cash and cash equivalents, accounts receivable and derivative financial instruments. We place our cash with high credit quality financial institutions. We place our derivative financial instruments with financial institutions that participate in our Credit Agreement and maintain an investment grade credit rating. Substantially all of our accounts receivable are due from operators of our oil and natural gas properties. These sales are generally unsecured and, in some cases, may carry a parent guarantee. We routinely assess the financial strength of our customers. Bad debt expense is recognized on an account-by-account review and when recovery is not probable. We have no off-balance-sheet credit exposure related to our operations or customers.

Mesquite accounted for 80% and 86% of total revenue for the years ended December 31, 2020 and 2019, respectively. We are highly dependent upon Mesquite as our most significant customer, and we expect to derive a substantial portion of our revenue from Mesquite in the foreseeable future. Accordingly, we are indirectly subject to the business risks of Mesquite.

Income Taxes

The Partnership and each of its wholly-owned subsidiary LLCs are treated as a partnership for federal and state income tax purposes. All of our taxable income or loss, which may differ considerably from net income or loss reported for financial reporting purposes, is passed through to the federal income tax returns of our members. As such, no federal income tax for these entities has been provided for in the accompanying financial statements.

Earnings per Unit

Net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income (loss) based on provisions of the Amended Partnership Agreement, divided by the weighted average number of common units outstanding. The two-class method dictates that net income (loss) for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income (loss) be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income (loss) as if all of the income for the period had been distributed in accordance with the Amended Partnership Agreement. Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income (loss) per unit. Undistributed income is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units based on provisions of the Amended Partnership Agreement. Undistributed losses are not allocated to unvested restricted unit awards as they do not participate in net losses. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

Asset Retirement Obligations

Asset retirement obligations represent the present value of the estimated cash flows expected to be incurred to plug, abandon and remediate producing properties, excluding salvage values, at the end of their productive lives in accordance with applicable laws. The significant unobservable inputs to this fair value measurement include estimates of plugging, abandonment and remediation costs, asset life, inflation and the credit-adjusted risk-free rate. The inputs are calculated based on historical data as well as current estimates. When the liability is initially recorded, the carrying amount of the related long-lived asset is increased. Over time, accretion of the liability is recognized each period, and the capitalized cost is amortized over the useful life of the related asset and is included in accretion expense in the our consolidated statements of operations.

To estimate the fair value of an asset retirement obligation, the Partnership employs a present value technique, which reflects certain assumptions, including its credit-adjusted risk-free interest rate, inflation rate, the estimated settlement date of the liability and the estimated current cost to settle the liability. Changes in timing or to the original estimate of cash flows will result in changes to the carrying amount of the liability.

Oil and Natural Gas Properties

We follow the successful efforts method of accounting for our oil and natural gas production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties. Under this method of accounting, costs relating to the development of proved areas are capitalized when incurred.

Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed reserves. As more fully described in Note 7 “Oil and Natural Gas Properties and Related Equipment” to our consolidated financial statements, proved reserves estimates are subject to future revisions when additional information becomes available.

All other properties, including the gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

Estimated asset retirement costs are recognized when the asset is acquired or placed in service, and are amortized over proved reserves using the units-of-production method. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. Cash flow estimates for impairment testing are based on third party reserve reports and exclude derivative instruments. Refer to Note 7 "Oil and Natural Gas Properties and Related Equipment" to our consolidated financial statements for additional information.

Reserves of Natural Gas, NGLs and Oil

Our estimate of proved reserves is based on the quantities of natural gas, NGLs and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Management estimates the proved reserves attributable to our ownership based on various factors, including consideration of the reserve report prepared by Ryder Scott, an independent oil and natural gas consulting firm. On an annual basis, our proved reserve estimates and the reserve report prepared by Ryder Scott are reviewed by the Audit Committee and the Board. Our financial statements for 2020 and 2019 were prepared using Ryder Scott's estimates of our proved reserves.

Reserves and their relation to estimated future net cash flows impact our depletion and impairment calculations. As a result, adjustments to depletion and impairment are made concurrently with changes to reserve estimates. The accuracy of our reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Our proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the actual quantities of oil and natural gas eventually recovered.

Unit-Based Compensation

The Partnership records unit-based compensation expense for awards granted in accordance with the provisions of Accounting Standards Codification ("ASC") Topic 718, "Compensation—Stock Compensation." Unit-based compensation expense for these awards is based on the grant-date fair value and recognized over the vesting period using the straight-line method.

Investments

We follow the equity method of accounting when we do not exercise control over the investee, but we can exercise significant influence over the operating and financial policies of the investee. Under this method, our equity investments are carried originally at our acquisition cost, increased by our proportionate share of the investee's net income and by contributions made, and decreased by our proportionate share of the investee's net losses and by distributions received. We evaluate our equity investments for impairment when evidence indicates the carrying amount of our investment is no longer recoverable. Evidence of a loss in value might include, but would not necessarily be limited to, absence of an ability to recover the carrying amount of the investment or inability of the equity method investee to sustain an earnings capacity that would justify the carrying amount of the investment. When the estimated fair value of an equity investment is less than its carrying value and the loss in value is determined to be other than temporary, we recognize the excess of the carrying value over the estimated fair value as an impairment loss within earnings from equity investments in our consolidated statements of operations.

Earnout Derivative

We are required to pay Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite and other producers. The earnout derivative is accounted for under ASC 815, and we measure its fair value through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios.

3. REVENUE RECOGNITION

Revenue from Contracts with Customers

We account for revenue from contracts with customers in accordance with ASC 606. The unit of account in ASC 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. ASC 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

Disaggregation of Revenue

We recognized revenue of $57.0 million and $76.6 million for the years ended December 31, 2020 and 2019, respectively. We disaggregate revenue based on type of revenue and product type. In selecting the disaggregation categories, we considered a number of factors, including disclosures presented outside the financial statements, such as in our earnings release and investor presentations, information reviewed internally for evaluating performance, and other factors used by the Partnership or the users of its financial statements to evaluate performance or allocate resources. We have concluded that disaggregating revenue by type of revenue and product type appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

Midstream Segment

The Seco Pipeline Transportation Agreement is the only contract that we account for under ASC 606. The Gathering Agreement is classified as an operating lease and is accounted for under ASC 842, "Leases", and is reported as gathering and transportation lease revenue in our consolidated statements of operations.

We account for income from our unconsolidated equity method investments as earnings from equity investments in our consolidated statements of operations. Earnings from these equity method investments are further discussed in Note 11 "Investments."

Production Segment

Our oil, natural gas, and NGL revenue is marketed and sold on our behalf by the respective asset operators. We are not party to the contracts with the third-party customers. However, we are party to joint operating agreements, which we account for under ASC 808 and revenues for these arrangements is recognized based on the information provided to us by the operators.

We additionally recognize and present changes in the fair value of our commodity derivative instruments within natural gas sales and oil sales in the consolidated statements of operations, which is accounted for under ASC 815, "Derivatives and Hedging".

Performance Obligations

Under the Seco Pipeline Transportation Agreement, we agreed to provide transportation services of certain quantities of natural gas from the receipt point to the delivery point. Each MMBtu of natural gas transported is distinct and the transportation services performed on each distinct molecule of product is substantially the same in nature. We applied the series guidance and treat these services as a single performance obligation satisfied over time using volumes delivered as the measure of progress. The Seco Pipeline Transportation Agreement requires payment within 30 days following the calendar month of delivery.

The Seco Pipeline Transportation Agreement contains variable consideration in the form of volume variability. As the distinct goods or services (rather than the series) are considered for the purpose of allocating variable consideration, we have taken the optional exception under ASC 606 which is available only for wholly unsatisfied performance obligations for which the criteria in ASC 606 have been met. Under this exception, neither estimation of variable consideration nor disclosure of the transaction price allocated to the remaining performance obligations is required. Revenue is alternatively recognized in the period that control is transferred to the customer and the respective variable component of the total transaction price is resolved.

For forms of variable consideration that are not associated with a specific volume (such as late payment fees) and thus do not meet allocation exception, estimation is required. These fees, however, are immaterial to our consolidated financial statements and have a low probability of occurrence. As significant reversals of revenue due to this variability are not probable, no estimation is required.

Contract Balances

Under our sales contracts, we invoice customers after our performance obligations have been satisfied, at which point payment is unconditional. Accordingly, our contracts do not give rise to contract assets or liabilities under ASC 606. At December 31, 2020, and 2019 our accounts receivable from contracts with customers were $1.9 million and $1.1 million, respectively, and are presented within accounts receivable – related entities on the consolidated balance sheets.

4. FAIR VALUE MEASUREMENTS

Measurements of fair value of derivative instruments are classified according to the fair value hierarchy, which prioritizes the inputs to the valuation techniques used to measure fair value. Fair value is the price that would be received upon the sale of an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Fair value measurements are classified and disclosed in one of the following categories:

Level 1: Measured based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. Active markets are considered those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2: Measured based on quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the term of the instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace.

Level 3: Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (i.e., supported by little or no market activity).

Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2020 (in thousands):

	Fair Value Measurements at December 31, 2020			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Other liabilities				
Warrant	$ —	$ (1,418)	$ —	$ (1,418)
Total	$ —	$ (1,418)	$ —	$ (1,418)

The following table summarizes the fair value of our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2019 (in thousands):

	Fair Value Measurements at December 31, 2019			
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)	Fair Value
Commodity derivative instrument				
Derivative liabilities	$ —	$ (759)	$ —	$ (759)
Other liabilities				
Warrant	—	(629)	—	(629)
Total	$ —	$ (1,388)	$ —	$ (1,388)

As of December 31, 2020 and 2019, the estimated fair value of cash and cash equivalents, accounts receivable, other current assets and current liabilities approximated their carrying value due to their short-term nature.

Fair Value on a Non-Recurring Basis

The Partnership follows the provisions of Topic 820-10 for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. The fair value measurements of assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs under the fair value hierarchy. We periodically review oil and natural gas properties and related equipment for impairment when facts and circumstances indicate that their carrying values may not be recoverable.

A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 9 "Asset Retirement Obligation."

The following table summarizes the non-recurring fair value measurements of our production assets as of December 31, 2020 (in thousands):

	Fair Value Measurements at December 31, 2020		
	Active Markets for Identical Assets (Level 1)	Observable Inputs (Level 2)	Unobservable Inputs (Level 3)
Impairment[(a)]	$ —	$ —	$ 12,884
Total net assets	$ —	$ —	$ 12,884

(a) During the year ended December 31, 2020, we recorded non-cash impairment charges of $23.4 million to impair our producing oil and natural gas properties and $0.9 million to impair the Seco Pipeline. The carrying values of the impaired properties were reduced to a fair value of $12.9 million, estimated using inputs characteristic of a Level 3 fair value measurement.

We had no non-recurring fair value measurements of our production assets as of December 31, 2019.

The fair values of oil and natural gas properties and related equipment were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties and related equipment include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; (v) estimated throughput; and (vi) a market-based weighted average cost of capital rate of 15%. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

A reconciliation of the beginning and ending balances of the Partnership's asset retirement obligations is presented in Note 9 ''Asset Retirement Obligation.''

Class C Preferred Units – As part of the Exchange (defined in Note 16 "Partners' Capital"), Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and the Warrant in a privately negotiated transaction. The Class C Preferred Units were measured using valuation techniques that convert a future obligation to a single discounted amount. We have therefore classified the fair value measurements of the Class C Preferred units as Level 2 and are presented within "Class C Preferred Units" on the Consolidated Balance Sheets.

Seco Pipeline – During the years ended December 31, 2020 and 2019, we recorded non-cash impairment charges of $0.9 million and $32.1 million, respectively, to impair the Seco Pipeline. The carrying value of the Seco Pipeline was reduced to a fair value of zero, estimated based on an inputs characteristic of a Level 3 fair value measurement.

The fair value of the Seco Pipeline was measured using probabilistic valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of the Seco Pipeline include estimates of: (i) future operating and development costs; (ii) estimated future cash flows; and (iii) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Partnership's management at the time of the valuation and are the most sensitive and subject to change.

Fair Value of Financial Instruments

The estimated fair value amounts of financial instruments have been determined using available market information and valuation methodologies described below. We prioritize the use of the highest level inputs available in determining fair value such that fair value measurements are determined using the highest and best use as determined by market participants and the assumptions that they would use in determining fair value.

Credit Agreement – We believe that the carrying value of our Credit Agreement (defined in Note 6 "Debt") approximates its fair value because the interest rates on the debt approximate market interest rates for debt with similar terms. The debt is classified as a Level 2 input in the fair value hierarchy and represents the amount at which the instrument could be valued in an exchange during a current transaction between willing parties. The Credit Agreement is discussed further in Note 6 "Debt."

Derivative Instruments – The income valuation approach, which involves discounting estimated cash flows, is primarily used to determine recurring fair value measurements of our derivative instruments classified as Level 2 inputs. Our commodity derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of oil and natural gas prices and an appropriate discount rate. Our interest rate derivatives are valued using the terms of the individual derivative contracts with our counterparties, expected future levels of the LIBOR interest rates and an appropriate discount rate. We did not have any interest rate or commodity derivatives as of December 31, 2020.

Warrant – As part of the Exchange, the Partnership issued to Stonepeak the Warrant which entitles the holder to receive junior securities representing ten percent of junior securities deemed outstanding when exercised. The Warrant expires on the later of August 2, 2026 or 30 days following the full redemption of the Class C Preferred Units. There is no strike price associated with the exercise of the Warrant. The Warrant is valued using ten percent of the junior securities deemed outstanding and the common unit price as of the balance sheet date. We have therefore classified the fair value measurements of the Warrant as Level 2 and is presented within other liabilities on the consolidated balance sheets.

Earnout Derivative – We are required to pay Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite and other producers. The earnout derivative was valued through the use of a Monte Carlo simulation model which utilized observable inputs such as the earnout price and volume commitment, as well as unobservable inputs related to the weighted probabilities of various throughput scenarios. We have therefore classified the fair value measurements of the earnout derivative as Level 3 inputs. There was no change in fair value of the earnout derivative during the years ended December 31, 2020 and 2019.

5. DERIVATIVE AND FINANCIAL INSTRUMENTS

To reduce the impact of fluctuations in oil and natural gas prices on our revenues, we periodically enter into derivative contracts with respect to a portion of our projected oil and natural gas production through various transactions that fix or modify the future prices to be realized. These hedging activities are intended to support oil and natural gas prices at targeted levels and to manage exposure to oil and natural gas price fluctuations. It is never our intention to enter into derivative contracts for speculative trading purposes.

Under Topic 815, “Derivatives and Hedging”, all derivative instruments are recorded on the consolidated balance sheets at fair value as either short-term or long-term assets or liabilities based on their anticipated settlement date. We will net derivative assets and liabilities for counterparties where we have a legal right of offset. Changes in the derivatives’ fair values are recognized currently in earnings unless specific hedge accounting criteria are met. We have not elected to designate any of our current derivative contracts as hedges; however, changes in the fair value of all of our derivative instruments are recognized in earnings and included in natural gas sales and oil sales in the consolidated statements of operations. As of December 31, 2020, all of our commodity derivative contracts have matured.

The following table sets forth a reconciliation of the changes in fair value of the Partnership’s commodity derivatives for the years ended December 31, 2020 and 2019 (in thousands):

	Years Ended December 31,	
	2020	2019
Beginning fair value of commodity derivatives	$ (759)	$ 3,914
Net gains (losses) on crude oil derivatives	3,814	(4,031)
Net gains on natural gas derivatives	87	259
Net settlements received on derivative contracts:		
Oil	(2,829)	(807)
Natural gas	(313)	(94)
Ending fair value of commodity derivatives	$ —	$ (759)

The effect of derivative instruments on our consolidated statements of operations was as follows (in thousands):

Derivative Type	Location of Gain (Loss) in Income	Years Ended December 31,	
		2020	2019
Commodity – Mark-to-Market	Oil sales	$ 3,814	$ (4,031)
Commodity – Mark-to-Market	Natural gas sales	87	259
		$ 3,901	$ (3,772)

Earnout Derivative

Refer to Note 4 “Fair Value Measurements”.

6. DEBT

Credit Agreement

We have entered into a credit facility with Royal Bank of Canada, as administrative agent and collateral agent, and the lenders party thereto (as amended by the Tenth Amendment to Third Amended and Restated Credit Agreement (the “Credit Agreement”). The Credit Agreement provides a quarterly amortizing term loan of $155.0 million (the “Term Loan”) and a maximum revolving credit amount of $17.5 million, which is reduced to the lesser of (i) $15.0 million through May 14, 2021 and (ii) from and after May 15, 2021, the positive difference of the Borrowing Base minus the aggregate outstanding principal amount of the Term Loan (the “Revolving Loan”). The Credit Agreement is a current liability that matures on September 30, 2021. We expect to refinance or extend the maturity of the Credit Agreement prior to its maturity date. However, we may not be able to refinance or extend the maturity of the Credit Agreement or, if we are able to refinance or extend the maturity, we may not be able to do so with borrowing and debt issue costs, terms, covenants, restrictions, commitment amount or a borrowing base favorable to us. Borrowings under the Credit Agreement are secured by various mortgages of both midstream and upstream properties that we own as well as various security and pledge agreements among us, certain of our subsidiaries and the administrative agent.

On November 6, 2020, the Partnership, as borrower, entered into that certain Tenth Amendment to the Third Amended and Restated Credit Agreement with the guarantors party thereto, Royal Bank of Canada, as administrative agent and collateral agent (the "Agent") and the lenders party thereto (each a "Lender") (the "Credit Agreement Amendment" and the Third Amended and Restated Credit Agreement, as amended by the Tenth Amendment, the "Amended Credit Agreement"). Pursuant to the Credit Agreement Amendment, the parties thereto agreed to, among other things: (a) amend the initial aggregate commitment amount under the first lien revolving credit facility to reduce such amount to $17.5 million, including a further limitation on such amount to $15.0 million through May 14, 2021; (b) amend the conditions precedent to the obligations of any Lender to make a Loan (as defined in the Amended Credit Agreement) to provide that through May 14, 2021, a Borrowing Base Deficiency (as defined in the Amended Credit Agreement) may exist; (c) amend the annual financial statements and annual budget affirmative covenant to provide that the Partnership's audited annual financial statements as reported on by the Partnership's independent public accountants may be delivered with a "going concern" or like qualification or exception, if such qualification or exception results from (i) any actual or prospective breach of the financial covenants set forth in Section 9.01 of the Amended Credit Agreement or (ii) the fact that the final maturity date of any Debt (as defined in the Amended Credit Agreement) is less than one year after the date of such report, and does not otherwise include any qualification or exception as to the scope of such audit; and (d) include a new post-closing covenant requiring the Partnership to either engage an Advisory Firm (as defined in the Credit Agreement Amendment) or certify that the Partnership has taken material steps, in either case, to implement a strategic transaction generating net cash proceeds reasonably expected to be greater than an amount that will allow the Partnership to repay in full all outstanding obligations under the Loan Documents (as defined in the Amended Credit Agreement) that is anticipated to close by August 31, 2021.

Borrowings under the Credit Agreement are available for limited direct investment in oil and natural gas properties, midstream properties, acquisitions, and working capital and general business purposes. The Credit Agreement has a sub-limit of up to $2.5 million which may be used for the issuance of letters of credit. Pursuant to the Credit Agreement, the initial aggregate commitment amount under the Term Loan is $155.0 million, subject to quarterly $10.0 million principal and other mandatory prepayments. The initial borrowing base under the Credit Agreement was $235.5 million. The borrowing base is equal to the sum of the rolling four quarter EBITDA of our midstream operations and the amount of distributions received from the Carnero JV multiplied by 4.5 or a lower number dependent upon natural gas volumes flowing through Western Catarina Midstream. Outstanding borrowings in excess of our borrowing base must be repaid within 45 days. As of December 31, 2020, the borrowing base under the Credit Agreement was $129.1 million and we had $111.0 million of debt outstanding, consisting of $105.0 million under the Term Loan and $6.0 million under the Revolving Loan. We are required to make mandatory amortizing payments of outstanding principal on the Term Loan of $10 million per fiscal quarter. The maximum revolving credit amount is $15.0 million leaving us with $9.0 million in unused borrowing capacity. There were no letters of credit outstanding under our Credit Agreement as of December 31, 2020.

At our election, interest for borrowings under the Credit Agreement are determined by reference to (i) the LIBOR plus an applicable margin between 2.50% and 3.00% per annum based on net debt to EBITDA or (ii) a domestic bank rate ("ABR") plus an applicable margin between 1.50% and 2.00% per annum based on net debt to EBITDA plus (iii) a commitment fee of 0.500% per annum based on the unutilized maximum revolving credit. Interest on the borrowings for ABR loans and the commitment fee are generally payable quarterly. Interest on the borrowings for LIBOR loans are generally payable at the applicable maturity date.

The Credit Agreement contains various covenants that limit, among other things, our ability to incur certain indebtedness, grant certain liens, merge or consolidate, sell all or substantially all of our assets, make certain loans, acquisitions, capital expenditures and investments, and pay distributions to unitholders.

In addition, we are required to maintain the following financial covenants:

- current assets to current liabilities of at least 1.0 to 1.0 at all times; and
- senior secured net debt to consolidated adjusted EBITDA for the last twelve months, as of the last day of any fiscal quarter, of not greater than 3.5 to 1.0.

The Credit Agreement also includes customary events of default, including events of default relating to non-payment of principal, interest or fees, inaccuracy of representations and warranties when made or when deemed made, violation of covenants, cross-defaults, bankruptcy and insolvency events, certain unsatisfied judgments, loan documents not being valid and a change in control. A change in control is generally defined as the occurrence of one of the following events: (i) our existing general partner ceases to be our sole general partner or (ii) certain specified persons shall cease to own more than 50% of the equity interests of our general partner or shall cease to control our general partner. If an event of default occurs, the lenders will be able to accelerate the maturity of the Credit Agreement and exercise other rights and remedies.

At December 31, 2020, we were in compliance with the financial covenants contained in the Credit Agreement. We monitor compliance on an ongoing basis. If we are unable to remain in compliance with the financial covenants contained in our Credit Agreement or maintain the required ratios discussed above, the lenders could call an event of default and accelerate the outstanding debt under the terms of the Credit Agreement, such that our outstanding debt could become then due and payable. We may request waivers of compliance from the violated financial covenants from the lenders, but there is no assurance that such waivers would be granted.

Debt Issuance Costs

As of December 31, 2020 and 2019, our unamortized debt issuance costs were approximately $0.8 million and $1.2 million, respectively. These costs are amortized to interest expense in our consolidated statements of operations over the life of our Credit Agreement. Amortization of debt issuance costs recorded during the years ended December 31, 2020 and 2019 were approximately $0.8 million and $1.3 million, respectively.

7. OIL AND NATURAL GAS PROPERTIES AND RELATED EQUIPMENT

Gathering and transportation assets consist of the following (in thousands):

	December 31,	
	2020	**2019**
Gathering and transportation assets		
Midstream assets	$ 187,977	$ 186,941
Less: Accumulated depreciation, amortization and impairment	(82,710)	(74,648)
Total gathering and transportation assets, net	$ 105,267	$ 112,293

Oil and natural gas properties consist of the following (in thousands):

	December 31,	
	2020	**2019**
Oil and natural gas properties and related equipment		
Proved property	$ 112,471	$ 112,476
Less: Accumulated depreciation, depletion, amortization and impairments	(94,843)	(69,541)
Total oil and natural gas properties and equipment, net	$ 17,628	$ 42,935

Oil and Natural Gas Properties. We follow the successful efforts method of accounting for our oil and natural gas production activities. Under this method of accounting, costs relating to leasehold acquisition, property acquisition and the development of proved areas are capitalized when incurred. If proved reserves are found on an undeveloped property, leasehold cost is transferred to proved properties.

Proved Reserves. Accounting rules require that we price our oil and natural gas proved reserves at the preceding twelve-month average of the first-day-of-the-month reference prices as adjusted for location and quality differentials. Such SEC-required prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts. Our proved reserve estimates exclude the effect of any derivatives we have in place.

Our estimate of proved reserves is based on the quantities of natural gas, NGLs, and oil that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters. Proved reserves are calculated based on various factors, including consideration of an independent reserve engineers' report on proved reserves and an economic evaluation of all of our properties on a well-by-well basis. The process used to complete the estimates of proved reserves at December 31, 2020 and 2019 is described in detail in Note 19 "Supplemental Information on Oil and Natural Gas Producing Activities."

Reserves and their relation to estimated future net cash flows impact depletion and impairment calculations. As a result, adjustments to depletion and impairments are made concurrently with changes to reserve estimates. The accuracy of reserve estimates is a function of many factors including the following: the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgments of the individuals preparing the estimates.

Proved reserve estimates are a function of many assumptions, all of which could deviate significantly from actual results. As such, reserve estimates may materially vary from the ultimate quantities of oil and natural gas eventually recovered.

Depreciation, Depletion and Amortization. Depreciation and depletion of producing oil and natural gas properties is recorded at the field level, based on the units-of-production method. Unit rates are computed for unamortized drilling and development costs using proved developed reserves and for unamortized leasehold and proved property acquisition costs using all proved reserves. Acquisition costs of proved properties are amortized on the basis of all proved reserves, developed and undeveloped, and capitalized development costs (including wells and related equipment and facilities) are amortized on the basis of proved developed reserves.

All other properties, including the gathering and transportation assets, are stated at historical acquisition cost, net of any impairments, and are depreciated using the straight-line method over the useful lives of the assets, which range from 3 to 15 years for furniture and equipment, up to 36 years for gathering facilities, and up to 40 years for transportation assets.

Impairment of Oil and Natural Gas Properties and Other Non-Current Assets. Oil and natural gas properties are reviewed for impairment on a field-by-field basis when facts and circumstances indicate that their carrying value may not be recoverable. We assess impairment of capitalized costs of proved oil and natural gas properties by comparing net capitalized costs to estimated undiscounted future net cash flows using expected prices. If net capitalized costs exceed estimated undiscounted future net cash flows, the measurement of impairment is based on estimated fair value, which would consider estimated future discounted cash flows. The cash flow estimates are based upon third-party reserve reports using future expected oil and natural gas prices adjusted for basis differentials. Other inputs, besides reserves, used to determine the fair values of proved properties include estimates of: (i) future operating and development costs; (ii) future commodity prices; and (iii) a market-based weighted average cost of capital rate. Cash flow estimates for impairment testing exclude derivative instruments.

During the year ended December 31, 2020, we recorded non-cash impairment charges of $23.4 million to impair our producing oil and natural gas properties. We did not impair our producing oil and natural gas properties during the year ended December 31, 2019.

Depreciation, depletion and amortization consisted of the following (in thousands):

	Years Ended December 31,	
	2020	**2019**
Depreciation, depletion and amortization of oil and natural gas-related assets	$ 2,218	$ 3,942
Depreciation and amortization of gathering and transportation related assets	7,195	7,931
Amortization of intangible assets	13,460	13,460
Total Depreciation, depletion and amortization	$ 22,873	$ 25,333

The recoverability of gathering and transportation assets is evaluated when facts or circumstances indicate that their carrying value may not be recoverable. Asset recoverability is measured by comparing the carrying value of the asset or asset group with its expected future pre-tax undiscounted cash flows. These cash flow estimates require us to make projections and assumptions for many years into the future for pricing, demand, competition, operating cost and other factors. If the carrying amount exceeds the expected future undiscounted cash flows, we recognize an impairment equal to the excess of net book value over fair value. The determination of the fair value using present value techniques requires us to make projections and assumptions regarding the probability of a range of outcomes and the rates of interest used in the present value calculations. Any changes we make to these projections and assumptions could result in significant revisions to our evaluation of recoverability of our gathering and transportation assets and the recognition of additional impairments. Upon disposition or retirement of gathering and transportation assets, any gain or loss is recorded to operations.

For the year ended December 31, 2020, we recorded an impairment charge on the Seco Pipeline of $0.9 million. On January 13, 2020, we received a written notice from Mesquite terminating the Seco Pipeline Transportation Agreement effective February 12, 2020. For the year ended December 31, 2019, we recorded a non-cash charge of $32.1 million, to impair the Seco Pipeline.

Asset Retirement Obligation. As described in Note 9 “Asset Retirement Obligation,” estimated asset retirement costs are recognized when the asset is acquired or placed in service. Costs associated with oil and natural gas properties are amortized over proved developed reserves using the units-of-production method. Costs associated with gathering and transportation assets are depreciated using the straight-line method over the useful lives of the asset. Asset retirement costs are estimated by our engineers using existing regulatory requirements and anticipated future inflation rates.

8. PROVISION FOR INCOME TAXES

Publicly traded partnerships like ours are treated as corporations unless they have 90% or more in qualifying income (as that term is defined in the Internal Revenue Code). We satisfied this requirement in each of the years ended December 31, 2020 and 2019 and, as a result, are not subject to federal income tax. However, our partners are individually responsible for paying federal income taxes on their share of our taxable income. Net earnings for financial reporting purposes may differ significantly from taxable income reportable to our unitholders as a result of differences between the tax basis and financial reporting basis of certain assets and liabilities and other factors. We do not have access to information regarding each partner's individual tax basis in our limited partner interests.

Provision for income taxes reflects franchise tax obligations in the state of Texas (the “Texas Margin Tax”). Deferred income tax assets and liabilities are recognized for temporary differences between the assets and liabilities of our tax paying entities for financial reporting and tax purposes.

Our federal and state income tax provision (benefit) is summarized below:

	Years Ended December 31, 2020	2019
Current:		
Federal	$ —	$ —
State	128	328
Total current	128	328
Deferred:		
Federal	—	—
State	(104)	(126)
Total deferred	(104)	(126)
Total provision for income taxes	$ 24	$ 202

A reconciliation of the provision for (benefit from) income taxes with amounts determined by applying the statutory U.S. federal income tax rate to income (loss) before income taxes is as follows (in thousands):

	Years Ended December 31, 2020	2019
Pre-tax net book loss	$ (118,737)	$ (50,940)
Texas Margin Tax [(a)]	36	126
Return to accrual	(12)	76
Provision for income taxes	$ 24	$ 202
Effective income tax rate	(0.02)%	(0.40)%

(a) Although the Texas Margin Tax is not considered a state income tax, it has the characteristics of an income tax since it is determined by applying a tax rate to a base that considers our Texas-sourced revenues and expenses.

The following table presents the significant components of deferred tax assets and deferred tax liabilities at the dates indicated (in thousands):

	December 31, 2020	2019
Deferred tax assets (liabilities):		
Derivative assets	$ (29)	$ (23)
Depreciable, depletable property, plant and equipment	129	21
Other	4	2
Deferred tax assets (liabilities):	104	—
Valuation allowance	—	—
Total deferred tax assets (liabilities)	$ 104	$ —

The Partnership assessed the available positive and negative evidence to determine that a valuation allowance was not required for a portion of its deferred tax assets because it is more likely than not that the deferred tax assets will be realized.

As of December 31, 2020 and 2019, the Partnership had no material uncertain tax positions.

The Partnership files income tax returns in the U.S. and various state jurisdictions. The Partnership is no longer subject to examination by federal income tax authorities prior to 2017. State statutes vary by jurisdiction.

9. ASSET RETIREMENT OBLIGATION

We recognize the fair value of a liability for an ARO in the period in which it is incurred if a reasonable estimate of fair value can be made. Each period, we accrete the ARO to its then present value. The associated asset retirement cost ("ARC") is capitalized as part of the carrying amount of our oil and natural gas properties, equipment and facilities or gathering and transportation assets. Subsequently, the ARC is depreciated using the units-of-production method for production assets and the straight-line method for midstream assets. The AROs recorded by us relate to the plugging and abandonment of oil and natural gas wells and decommissioning of oil and natural gas gathering and other facilities.

Inherent in the fair value calculation of ARO are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions result in adjustments to the recorded fair value of the existing ARO, a corresponding adjustment is made to the ARC capitalized as part of the oil and natural gas properties, equipment and facilities or gathering and transportation assets.

The following table is a reconciliation of the ARO (in thousands):

	December 31,	
	2020	2019
Asset retirement obligation, beginning balance	$ 6,898	$ 6,200
Liabilities added from escalating working interests	—	172
Accretion expense	567	526
Asset retirement obligation, ending balance	$ 7,465	$ 6,898

Additional AROs increase the liability associated with new oil and natural gas wells and other facilities as these obligations are incurred. Abandonments of oil and natural gas wells and other facilities reduce the liability for AROs. In 2020 and 2019, there were no significant expenditures for abandonments and there were no assets legally restricted for purposes of settling existing AROs.

10. INTANGIBLE ASSETS

Intangible assets are comprised of customer and marketing contracts. The intangible assets balance as of December 31, 2020 is related to the Gathering Agreement with Mesquite that was entered into as part of the Western Catarina Midstream transaction. Pursuant to the 15-year agreement, Mesquite tenders all of its crude oil, natural gas and other hydrocarbon-based product volumes on 35,000 dedicated acres in the Western Catarina of the Eagle Ford Shale in Texas for processing and transportation through Western Catarina Midstream, with a right to tender additional volumes outside of the dedicated acreage. These intangible assets are being amortized using the straight-line method over the 15 year life of the agreement.

Amortization expense for the years ended December 31, 2020 and 2019 was $13.5 million, respectively. These costs are amortized to depreciation, depletion, and amortization expense in our consolidated statement of operations. Intangible assets as of December 31, 2020 and 2019 are detailed below (in thousands):

	December 31,	
	2020	2019
Beginning balance	$ 145,246	$ 158,706
Amortization	(13,460)	(13,460)
Ending balance	$ 131,786	$ 145,246

11. INVESTMENTS

In July 2016, we completed a transaction pursuant to which we acquired from Mesquite a 50% interest in Carnero Gathering, LLC ("Carnero Gathering"), a joint venture that was 50% owned and operated by Targa Resources Corp. (NYSE: TRGP) ("Targa"), for an initial payment of approximately $37.0 million and the assumption of remaining capital commitments to Carnero Gathering, estimated at approximately $7.4 million as of the acquisition date (the "Carnero

Gathering Transaction”). The fair value of the intangible asset for the contractual customer relationship related to Carnero Gathering was valued at approximately $13.0 million. This amount is being amortized over a contract term of 15 years and decreases earnings from equity investments in our consolidated statements of operations. As part of the Carnero Gathering Transaction, we are required to pay Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite and other producers. See Note 4 “Fair Value Measurements” for further discussion of the earnout derivative.

In November 2016, we completed a transaction pursuant to which we acquired from Mesquite a 50% interest in Carnero Processing, LLC (“Carnero Processing”), a joint venture that was 50% owned and operated by Targa, for aggregate cash consideration of approximately $55.5 million and the assumption of remaining capital contribution commitments to Carnero Processing, estimated at approximately $24.5 million as of the date of acquisition (the “Carnero Processing Transaction”).

In May 2018, we executed a series of agreements with Targa and other parties pursuant to which, among other things: (1) the parties merged their respective 50% interests in Carnero Gathering and Carnero Processing (the “Carnero JV Transaction”) to form an expanded 50 / 50 joint venture in South Texas, within Carnero G&P, LLC (“the Carnero JV”), (2) Targa contributed 100% of the equity interest in the Silver Oak II Gas Processing Plant (“Silver Oak II”), located in Bee County Texas, to the Carnero JV, which expands the processing capacity of the Carnero JV from 260 MMcf/d to 460 MMcf/d, (3) Targa contributed certain capacity in the 45 miles of high pressure natural gas gathering pipelines owned by Carnero Gathering that connect Western Catarina Midstream to nearby pipelines and the Raptor Gas Processing Facility (the “Carnero Gathering Line”) to the Carnero JV resulting in the Carnero JV owning all of the capacity in the Carnero Gathering Line, which has a design limit (without compression) of 400 MMcf/d, (4) the Carnero JV received a new dedication from Mesquite and its working interest partners of over 315,000 acres located in the Western Eagle Ford on Mesquite’s Comanche Asset pursuant to a new long-term firm gas gathering and processing agreement. The agreement with Mesquite, which was approved by all of the unaffiliated Comanche working interest partners, establishes commercial terms for the gathering of gas on the Carnero Gathering Line and processing at the Raptor Gas Processing Facility and Silver Oak II. Prior to execution of the agreement, Comanche volumes were gathered and processed on an interruptible basis, with the processing capabilities of the Carnero JV limited by the capacity of the Raptor Gas Processing Facility. As a result of the Carnero JV Transaction we now record our share of earnings and losses from the Carnero JV using the Hypothetical Liquidation at Book Value (“HLBV”) method of accounting. The HLBV is a balance-sheet approach that calculates the amount we would have received if the Carnero JV were liquidated at book value at the end of each measurement period. The change in our allocated amount during the period is recognized in our consolidated statements of operations. In the event of liquidation of the Carnero JV, available proceeds are first distributed to any priority return and unpaid capital associated with Silver Oak II, and then to members in accordance with their capital accounts.

As of December 31, 2020, the Partnership had paid approximately $124.2 million for its investment in the Carnero JV related to the initial payments and contributed capital. The Partnership has accounted for this investment using the equity method. Targa is the operator of the Carnero JV and has significant influence with respect to the normal day-to-day capital and operating decisions. We have included the investment balance in the equity investments caption on our consolidated balance sheets. For the year ended December 31, 2020, the Partnership recorded earnings of approximately $5.7 million in equity investments from the Carnero JV, which was offset by approximately $1.2 million related to the amortization of the contractual customer intangible asset. We have included these equity method earnings in the earnings from equity investments line within the consolidated statements of operations. Cash distributions of approximately $15.3 million were received during the year ended December 31, 2020.

Summarized financial information of unconsolidated entities is as follows (in thousands):

	Years Ended December 31,	
	2020	2019
Sales	$ 80,228	$ 159,508
Total expenses	63,121	145,837
Net income	$ 17,107	$ 13,671

12. COMMITMENTS AND CONTINGENCIES

We are required to pay Mesquite an earnout based on natural gas received above a threshold volume and tariff at designated delivery points from Mesquite and other producers. This earnout has an approximate value of zero as of December 31, 2020 and 2019. For the year ended December 31, 2020, natural gas received did not exceed the threshold. For the year ended December 31, 2019 payments totaling approximately $32.0 thousand were made.

13. RELATED PARTY TRANSACTIONS

Relationship with Stonepeak

Since October 14, 2015, Stonepeak Catarina has owned all of our issued and outstanding preferred units.

As of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) the Warrant that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights. Stonepeak also owns 100% of the issued and outstanding equity interests in SP Holdings, which is the sole member of our general partner. SP Holdings has the right to appoint all of the members of the Board of directors other than two directors which Stonepeak Catarina is entitled to designate pursuant to that certain Amended and Restated Board Representation and Standstill Agreement, dated as of August 2, 2019. Stonepeak controls us and our general partner and has the ability to appoint all of the members of the Board and is considered a related party of the Partnership.

Currently, four of our directors, Jack Howell, Luke Taylor, Michael Bricker and John T. Steen III are representatives of Stonepeak as either employees or operating partners of Stonepeak. Messrs. Howell, Taylor, Bricker and Steen do not receive separate compensation for their service on the Board, but they are entitled to indemnification related to their service as directors pursuant to the terms of our partnership agreement. Mr. Meisel receives certain compensation for his service on the Board. “See Part III, Item 11. Executive Compensation—Compensation of Directors.”

Relationship with Mesquite

Prior to emergence from the Mesquite Chapter 11 Case, Mesquite was considered a related party of the Partnership because (i) Antonio R. Sanchez, III, who served as the Chairman of the Board at such time, also served as the Chief Executive Officer of Mesquite, (ii) Patricio D. Sanchez, who served as a member of the Board and as our President and Chief Operating Officer at such time, also served as a senior vice president and Chief Operating Officer of Mesquite, and (iii) Mesquite and certain other members of the Sanchez family directly or indirectly owned approximately 24.3% of the issued and outstanding common units of the Partnership at such time. As of June 30, 2020, Mesquite is not considered a related party of the Partnership. Prior to the date of this Form 10-K, Antonio R. Sanchez, III resigned from his position as a member of the Board and the Chairman of the Board and Patricio D. Sanchez resigned from his position as a member of the Board and as our President and Chief Operating Officer.

Relationship with SP Holdings

We are controlled by our general partner, Evolve Transition Infrastructure GP LLC. The sole member of our general partner is SP Holdings which has no officers. The sole member of SP Holdings is Stonepeak Catarina and the managing member of SP Holdings is Stonepeak Catarina Upper Holdings, LLC, an affiliate of Stonepeak Catarina.

Shared Services Agreement

We have entered into the Shared Services Agreement with SP Holdings. In connection with providing the services under the Shared Services Agreement, SP Holdings receives compensation consisting of: (i) a quarterly fee equal to 0.375% of the value of our properties other than our assets located in the Mid-Continent region, (ii) reimbursement for all allocated overhead costs as well as any direct third-party costs incurred and (iii) for each asset acquisition, asset disposition and financing, a fee not to exceed 2% of the value of such transaction. Prior to August 2, 2019 each of these fees, not including the reimbursement of costs, was paid in cash unless SP Holdings elected for such fee to be paid in our equity.

However, on August 2, 2019, we and SP Holdings entered into a letter agreement providing that until such time as we redeem all of our issued and outstanding Class C Preferred Units, SP Holdings will elect to receive its fees, not including reimbursement of costs, in common units rather than cash. In addition, on November 8, 2019, we and SP Holdings entered into an additional letter agreement providing that during the period beginning with the fiscal quarter ended September 30, 2019 and continuing until the end of the fiscal quarter after the fiscal quarter in which we redeem all of our issued and outstanding Class C Preferred Units (the “Tolling Period”), SP Holdings would agree to delay receipt of its fees, not including reimbursement of costs. During the Tolling Period, we are required to keep an accurate ledger of the dollar amount of the fee applicable to each quarter within the Tolling Period and the daily closing price of our common units on the NYSE. Following the end of the Tolling Period we will provide a notice to SP Holdings including such ledgers and pay the accrued fees within thirty days of delivery of such notice. The Shared Services Agreement has a ten-year term and will be automatically renewed for an additional ten years unless we or SP Holdings provide notice of termination to the other with at least 180 days’ notice. For the fees earned during the year ended December 31, 2020, pursuant to the November 8, 2019 letter agreement, SP Holdings did not receive any fees, other than reimbursement of its costs. However, pursuant to the requirements under the November 8, 2019 letter agreement, we have determined that the fees earned during the years ended December 31, 2020 and 2019 are approximately $7.2 million and $7.3 million, respectively.

The Shared Services Agreement can be terminated (i) by either party at any time by 180 days’ prior written notice to the other party, (ii) by SP Holdings if there is an uncured material breach thereunder by the Partnership, or (iii) by the Partnership, subject to Board approval, if (1) there is an uncured material breach thereunder by SP Holdings or (2) there is a change in control of SP Holdings. Pursuant to the Standstill Agreement, the Partnership must obtain Stonepeak Catarina’s consent to its termination of the Shared Services Agreement. The Shared Services Agreement provides that if there is a termination other than by either party at the end of the Service Agreement’s term, by the Partnership for an uncured breach by SP Holdings, or by the Partnership upon a change of control of SP Holdings, then the Partnership will owe a termination payment to SP Holdings in an amount equal to $5,000,000 plus 5% of the transaction value of all asset acquisitions theretofore consummated. We estimate that this amount was in excess of $35.0 million as of December 31, 2020. Such termination fee may be payable in cash or common units. If the Partnership terminates upon 180 days’ prior notice then the Partnership must also pay to SP Holdings all costs and expenses of SP Holdings that result from such termination. To date, no notice of termination of the Shared Services Agreement has been delivered by SP Holdings, and the Partnership is continuing to discuss the Shared Services Agreement with SP Holdings.

Related Party Transactions

2019

Class C Preferred Unit Issuance and Warrant

On August 2, 2019, Stonepeak Catarina exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and a warrant exercisable for junior securities (the “Warrant”) in a privately negotiated transaction (the “Exchange”). In connection with the Exchange, the Partnership entered into (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (the “Amended Partnership Agreement) to set forth the terms of the Class C Preferred Units, (ii) the Amended and Restated Registration Rights Agreement with Stonepeak relating to the registered resale of common units issuable upon the exercise of the Warrant, and (iii) the Amended and Restated Board Representation and Standstill Agreement with Stonepeak. In addition, on August 2, 2019, the Partnership’s general partner entered into Amendment No. 3 to its Limited Liability Company Agreement to provide certain changes necessary in connection with the Exchange.

On August 2, 2019, in connection with the Exchange, Stonepeak Catarina received the Warrant. The Warrant may be exercised at any time and from time to time during the period beginning on August 2, 2019 and ending on the later of the seventh anniversary of such date and the date thirty days after the date on which all of the Class C Preferred Units have been redeemed for a number of Junior Securities (as such term is defined in the Warrant) equal to 10% of each applicable class of Junior Securities deemed outstanding as of the exercise date. No exercise price will be payable in connection with the exercise of the Warrant.

At the time of the Exchange and Warrant, Stonepeak Catarina owned all of the Partnership’s issued and outstanding Class B Preferred Units, representing an approximately 61.7% interest in the Partnership. Jack Howell and Luke Taylor, members of the Board during the year ended December 31, 2019, were also employees of Stonepeak at the time of the Exchange.

2020

Settlement Agreement

On June 6, 2020 the Partnership, our general partner and certain of our subsidiaries entered into the Settlement Agreement with Mesquite and certain of its subsidiaries. On June 30, 2020, the Bankruptcy Court entered an order approving the Settlement Agreement and the parties to the Settlement Agreement entered into or amended certain commercial contracts, including but not limited to, (i) Amendment No. 2, (ii) the Seco Catarina Agreement, and (iii) the Seco Comanche Agreement. Each such agreement will become effective only upon satisfaction of certain closing conditions described in the Settlement Agreement.

JT3 Consulting Agreement

On June 30, 2020, our general partner entered into that certain Consultancy Agreement (the “JT3 Consulting Agreement”) with JT3 Advisors LLC (“JT3 Advisors”). JT3 Advisors is an entity owned by John T Steen III, who has served as the Chairman of the Board since September 2020. Pursuant to the terms of the JT3 Consulting Agreement the Partnership pays JT3 Advisors a consulting fee of $20,000 per month for the provision of services to aid the Partnership in achieving its commercial goals, including analysis and assessment of potential commercial arrangements and recommendation of selected arrangements to our management.

Certain Transactions with Stonepeak

On November 16, 2020, the Partnership and Stonepeak Catarina entered the Stonepeak Letter Agreement wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The Stonepeak Letter Agreement also provides that Stonepeak Catarina will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the end of such quarter. The Letter Agreement Transactions were referred to the Conflicts Committee of the Board. The Conflicts Committee approved the Letter Agreement Transactions, recommended that the Board approve and authorize the execution and performance of the Letter Agreement Transactions, and verified that their approvals constituted “Special Approval” of the Letter Agreement Transactions under and pursuant to our partnership agreement. Following the approval and recommendation from the Conflicts Committee, the Board approved the Letter Agreement Transactions. An aggregate distribution of 22,274,869 common units was made to Stonepeak Catarina on February 1, 2021, following the satisfaction of certain issuance conditions. The approximate value of this transaction was $12.9 million.

On January 28, 2021, Stonepeak Catarina provided us with its notice of election to receive a Common Unit PIK Distribution for the fourth quarter of 2020. The aggregate distribution of 12,445,491 common units was made to Stonepeak Catarina on February 25, 2021, following the satisfaction of certain issuance conditions. The approximate value of this transaction was $12.9 million.

As a result of the foregoing transactions, as of March 16, 2021, Stonepeak owned (i) 39,623,443 common units, representing approximately 72.7% of our outstanding common units, (ii) all of our issued and outstanding Class C Preferred Units, (iii) the Warrant that entitled Stonepeak Catarina to receive junior securities of the Partnership (including common units) representing 10% of all junior securities deemed outstanding when exercised, (iv) the non-economic general partner interest in the Partnership and (v) all of our incentive distribution rights..

Pursuant to Section 15.1 of our partnership agreement, if at any time Stonepeak holds more than 80% of our outstanding common units and completes the Stonepeak LCR Transfer, Stonepeak will be able to cause our general partner or a controlled affiliate of our general partner to exercise the limited call right. Stonepeak would effect any such exercise by first completing the Stonepeak LCR Transfer and then causing our general partner to exercise its limited call right at a price equal to the greater of (1) the average of the daily closing price of our common units over the 20 trading days preceding the date three days before notice of exercise of the limited call right is first mailed and (2) the highest per-unit price paid by our general partner or any of its controlled affiliates for common units during the 90-day period preceding the date such notice is first mailed. As a result, common unitholders may be required to sell their common units at an undesirable time or price and may not receive any return or a negative return on their investment. Common unitholders may also incur tax liability upon a sale of their units. Our general partner is not obligated to obtain a fairness opinion regarding the value of common units to be repurchased upon exercise of the limited call right. Furthermore, there is no restriction in our partnership agreement that prevents our general partner from causing us to issue additional common units, including common units issued pursuant to the Stonepeak Letter Agreement or as a result of the termination or renegotiation of the Shared Services Agreement, and then exercising its limited call right. If our general partner exercises its limited call right, the effect would be to take the Partnership private and, if the common units are subsequently deregistered, the Partnership will no longer be subject to the reporting requirements of the Securities Exchange Act of 1934, as amended. As of March 16, 2021, the General Partner and its controlled affiliates do not own any Common Units.

14. UNIT-BASED COMPENSATION

The Partnership's Long-Term Incentive Plan (the "LTIP") allows for restricted common unit grants. Restricted common unit activity under the Plan during the period is presented in the following table:

	Number of Restricted Units		Weighted Average Grant Date Fair Value Per Unit
Outstanding at December 31, 2018	513,694	$	12.31
Granted	1,129,173		2.35
Vested	(382,690)		8.50
Returned/Cancelled	(104,710)		12.04
Outstanding at December 31, 2019	1,155,467	$	3.86
Vested	(338,840)		5.14
Returned/Cancelled	(133,456)		5.61
Outstanding at December 31, 2020	683,171	$	2.68

In April 2019, the Partnership issued 137,613 restricted common units pursuant to the LTIP to certain directors of the Partnership's general partner that vested immediately on the date of grant. In March 2019, the Partnership issued 991,560 restricted common units pursuant to the LTIP to certain officers and directors of the Partnership's general partner that vest over three years from the date of grant. The unit-based compensation expense for the awards was based on the fair value on the day before the grant date.

As of December 31, 2020, 974,393 common units remained available for future issuance to participants under the LTIP.

15. DISTRIBUTIONS TO UNITHOLDERS

The table below reflects the payment of cash distributions on common units related to the periods indicated.

Three months ended		Distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2019	$	0.1500	May 3, 2019	May 22, 2019	May 31, 2019

Beginning with the determination of the distribution for the second-quarter 2019, the Board determined to establish a cash reserve to pay down a portion of the Partnership's debt outstanding under the Credit Agreement. Following the establishment of the cash reserve, each quarter since the first-quarter 2019, the Board has determined that the Partnership did not have any available cash and, as a result, no cash distribution has been declared for the common units since the quarter ended March 31, 2019. As previously disclosed, our partnership agreement currently prohibits us from paying any distributions on our common units until we have redeemed all of the Class C Preferred Units. Following such redemption, the Credit Agreement may further limit our ability to pay distributions to unitholders.

The table below reflects the payment of distributions on Class B Preferred Units related to the periods indicated.

Three months ended	Cash distribution per unit	Date of declaration	Date of record	Date of distribution
March 31, 2019	$ 0.28225	May 3, 2019	May 22, 2019	May 31, 2019

On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units (the "Class C Preferred Units"). As a result the Partnership paid a distribution on the Class C Preferred Units in Class C Preferred PIK Units in lieu of a distribution on the Class B Preferred Units for the second-quarter 2019.

The table below reflects the payment of distributions on Class C Preferred Units related to the periods indicated.

Three months ended	Class C Preferred PIK distribution	Date of declaration	Date of record	Date of distribution
June 30, 2019	939,327	August 8, 2019	August 20, 2019	August 30, 2019
September 30, 2019	1,007,820	October 30, 2019	November 29, 2019	November 20, 2019
December 31, 2019	1,039,314	February 13, 2020	February 28, 2020	February 20, 2020
March 31, 2020	1,071,793	April 29, 2020	May 20, 2020	May 29, 2020
June 30, 2020	1,105,286	July 31, 2020	August 20, 2020	August 31, 2020

On November 16, 2020, the Partnership and Stonepeak entered into a letter agreement (the "Stonepeak Letter Agreement") wherein the parties agreed that the distribution on the Class C Preferred Units for the three months ended September 30, 2020 would be paid in common units instead of Class C Preferred PIK Units, cash or a combination thereof. The aggregate distribution of 22,274,869 common units was made to Stonepeak on February 1, 2021.

The Stonepeak Letter Agreement also provides that Stonepeak will be able to elect to receive distributions on the Class C Preferred Units in common units for any quarter following the third quarter of 2020 by providing written notice to the Partnership no later than the last day of the calendar month following the end of such quarter.

In accordance with the Stonepeak Letter Agreement, on January 28, 2021, the Partnership received written notice of Stonepeak's election to receive distributions on the Class C Preferred Units for the quarter ended December 31, 2020 in common units. The aggregate distribution of 12,445,491 common units was paid to Stonepeak on February 25, 2021.

16. PARTNERS' CAPITAL

Outstanding Units

As of December 31, 2020, we had no Class B Preferred Units outstanding, 36,474,436 Class C Preferred Units outstanding and 19,953,880 common units outstanding, which included 683,171 unvested restricted common units issued under the LTIP.

Common Unit Issuances

The Partnership did not issue any common units to SP Holdings in connection with providing services under the Shared Services Agreement during the year ended December 31, 2020.

Class B Preferred Unit Offering

On October 14, 2015, pursuant to the Class B Preferred Unit Purchase Agreement dated September 25, 2015, by and between the Partnership and Stonepeak Catarina Holdings LLC ("Stonepeak"), the Partnership sold and Stonepeak purchased 19,444,445 of the Partnership's newly created Class B Preferred Units (the "Class B Preferred Units") in a private placement transaction for an aggregate cash purchase price of $18.00 per Class B Preferred Unit, which resulted in gross proceeds to the Partnership of approximately $350.0 million. The Partnership used the net proceeds to pay a portion of the consideration for the acquisition of Western Catarina Midstream, along with the payment to Stonepeak of a fee equal to 2.25% of the consideration paid for the Class B Preferred Units.

On December 6, 2016, the Partnership issued an additional 9,851,996 Class B Preferred Units to Stonepeak. On January 25, 2017, the Partnership and Stonepeak entered into a Settlement Agreement and Mutual Release (the "Stonepeak Settlement Agreement") to settle a dispute arising from the calculation of an adjustment to the number of Class B Preferred Units issued. Pursuant to the Stonepeak Settlement Agreement, the Partnership issued 1,704,446 Class B Preferred Units to Stonepeak in a private placement transaction as partial consideration for the Settlement Agreement, with the "Class B Preferred Unit Price" being established at $11.29 per Class B Preferred Unit.

The Class B Preferred Units were accounted for as mezzanine equity on our consolidated balance sheet. The following table sets forth a reconciliation of the changes in mezzanine equity (in thousands):

		December 31, 2019
Mezzanine equity, beginning balance	$	349,857
Amortization of discount		1,708
Distributions		23,247
Distributions paid		(17,675)
Class B Preferred Unit exchange		(357,137)
Mezzanine equity, ending balance	$	—

On August 2, 2019, Stonepeak exchanged all of the issued and outstanding Class B Preferred Units for newly issued Class C Preferred Units and a warrant exercisable for junior securities (the "Warrant") in a private placement transaction (the "Exchange").

Class C Preferred Units

In connection with the Exchange, the Partnership entered into (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (the "Amended Partnership Agreement) to set forth the terms of the Class C Preferred Units, (ii) the Amended and Restated Registration Rights Agreement with Stonepeak relating to the registered resale of common units issuable upon the exercise of the Warrant, and (iii) the Amended and Restated Board Representation and Standstill Agreement with Stonepeak.

Under the terms of the Amended Partnership Agreement, commencing with the quarter ended on September 30, 2019, the holders of the Class C Preferred Units will receive a quarterly distribution of 12.5% per annum payable in cash. To the extent that Available Cash (as defined in the Amended Partnership Agreement) is insufficient to pay the distribution in cash, all or a portion of the distribution may be paid in Class C Preferred PIK Units. Commencing with the quarter ending March 31, 2022, the distribution rate will increase to 14% per annum. Distributions are to be paid on or about the last day of each of February, May, August and November following the end of each quarter and are charged to interest expense in our consolidated statements of operations.

The Exchange was accounted for as an extinguishment with the difference between the book value of the redeemed instrument and the fair value of the new instrument being considered a deemed contribution to common equity of approximately $103.8 million. The Class C Preferred Units are accounted for as a long-term liability on the consolidated balance sheet consisting of the following (in thousands):

	December 31,	
	2020	2019
Class C Preferred Units, beginning balance	$ 281,688	$ —
Private placement of Class C Preferred Units	—	353,500
Discount	—	(104,250)
Accretion of discount	38,938	13,129
Distribution accrual	24,579	19,309
Class C Preferred Units, ending balance	$ 345,205	$ 281,688

Warrant

On August 2, 2019, in connection with the Exchange, the Partnership issued to Stonepeak the Warrant which entitles the holder to receive junior securities representing ten percent of junior securities deemed outstanding when exercised. The Warrant expires on the later of August 2, 2026 or 30 days following the full redemption of the Class C Preferred Units. There is no strike price associated with the exercise of the Warrant. The Warrant is accounted for as a liability in accordance with ASC 480 and is presented within other liabilities on the consolidated balance sheet. Changes in the fair value of the Warrant are charged to interest expense in our consolidated statements of operations.

Earnings per Unit

Net income (loss) per common unit for the period is based on any distributions that are made to the unitholders (common units) plus an allocation of undistributed net income (loss), based on the provisions of the Amended Partnership Agreement, divided by the weighted average number of common units outstanding. The two-class method dictates that net income (loss) for a period be reduced by the amount of distributions and that any residual amount representing undistributed net income (loss) be allocated to common unitholders and other participating unitholders to the extent that each unit may share in net income (loss) as if all of the net income for the period had been distributed in accordance with the Amended Partnership Agreement. Unit-based awards granted but unvested are eligible to receive distributions. The underlying unvested restricted unit awards are considered participating securities for purposes of determining net income (loss) per unit. Undistributed income is allocated to participating securities based on the proportional relationship of the weighted average number of common units and unit-based awards outstanding. Undistributed losses (including those resulting from distributions in excess of net income) are allocated to common units based on provisions of the Amended Partnership Agreement. Undistributed losses are not allocated to unvested restricted unit awards as they do not participate in net losses. Distributions declared and paid in the period are treated as distributed earnings in the computation of earnings per common unit even though cash distributions are not necessarily derived from current or prior period earnings.

The Partnership's general partner does not have an economic interest in the Partnership and, therefore, does not participate in the Partnership's net income.

17. REPORTING SEGMENTS

"Midstream" and "Production" best describe the operating segments of the businesses that we separately report. The factors used to identify these reporting segments are based on the nature of the operations that are undertaken by each segment. The Midstream segment operates the gathering, processing and transportation of natural gas, NGLs and crude oil. The Production segment operates to produce crude oil and natural gas. These segments are broadly understood across the petroleum and petrochemical industries.

These functions have been defined as the operating segments of the Partnership because they are the segments (1) that engage in business activities from which revenues are earned and expenses are incurred; (2) whose operating results are regularly reviewed by the Partnership's chief operating decision maker ("CODM") to make decisions about resources to be allocated to the segment and to assess its performance; and (3) for which discrete financial information is available. Operating segments are evaluated for their contribution to the Partnership's consolidated results based on operating income, which is defined as segment operating revenues less expenses.

The following tables present financial information for each operating segment for the periods indicated based on our operating segments (in thousands):

	Years Ended December 31,			
	2020		2019	
	Production	Midstream	Production	Midstream
Segment revenues				
Natural gas sales	$ 427	$ —	$ 683	$ —
Oil sales	10,856	—	9,512	—
Natural gas liquid sales	254	—	539	—
Gathering and transportation sales	—	785	—	6,825
Gathering and transportation lease revenues	—	44,671	—	59,090
Total segment revenues	11,537	45,456	10,734	65,915
Segment operating costs				
Lease operating expenses	5,340	884	5,879	1,499
Transportation operating expenses	—	9,314	—	11,553
Production taxes	311	—	621	—
Depreciation, depletion and amortization	2,218	20,655	3,942	21,391
Asset impairments	23,355	867	—	32,119
Accretion expense	212	355	200	326
Total segment operating costs	31,436	32,075	10,642	66,888
Segment other income				
Earnings from equity investments	—	4,479	—	2,831
Total segment other income	—	4,479	—	2,831
Segment operating income (loss)	$ (19,899)	$ 17,860	$ 92	$ 1,858

	Years Ended December 31,	
	2020	2019
Reconciliation of segment operating income (loss) to net loss		
Total midstream operating income	$ 17,860	$ 1,858
Total production operating income (loss)	(19,899)	92
Total segment operating income (loss)	(2,039)	1,950
General and administrative expenses	(18,296)	(17,610)
Unit-based compensation expense	(2,602)	(1,351)
Interest expense, net	(95,871)	(39,789)
Other income	71	5,860
Income tax expense	(24)	(202)
Net loss	$ (118,761)	$ (51,142)

The following table summarizes the total assets and capital expenditures by operating segment as of December 31, 2020 and 2019 (in thousands):

	December 31, 2020			
	Production	Midstream	Corporate [(a)]	Total
Other financial information				
Total assets	$ 19,242	$ 331,926	$ 2,260	$ 353,428
Capital expenditures[(b)]	$ (5)	$ 1,943	$ —	$ 1,938

	December 31, 2019			
	Production	Midstream	Corporate [(a)]	Total
Other financial information				
Total assets	$ 45,550	$ 362,961	$ 5,929	$ 414,440
Capital expenditures[(b)]	$ 130	$ 775	$ —	$ 905

(a) Corporate assets not reviewed by the CODM on a segment basis consists of cash, certain prepaid expenses, office furniture and other assets.
(b) Inclusive of capital contributions made to equity method investments.

Revenue from Mesquite earned in our Midstream segment accounted for 80% and 86% of total revenue for the years ended December 31, 2020 and 2019, respectively. Because all remaining production properties are non-operated, there are no customers in the Production segment that exceed 10% of the Partnership's consolidated revenue.

18. VARIABLE INTEREST ENTITIES

The Partnership's investment in the Carnero JV represents a variable interest entity ("VIE") that could expose the Partnership to losses. The amount of losses the Partnership could be exposed to from the Carnero JV is limited to the capital investment of approximately $89.6 million.

As of December 31, 2020, the Partnership had invested approximately $124.2 million in the Carnero JV and no debt has been incurred by the Carnero JV. We have included this VIE in other assets, equity investments on the balance sheet.

Below is a tabular comparison of the carrying amounts of the assets and liabilities of the VIE and the Partnership's maximum exposure to loss as of December 31, 2020 and 2019 (in thousands):

	December 31,	
	2020	2019
Acquisitions, earnout and capital investments	$ 128,251	$ 128,140
Earnings in equity investments	30,455	25,976
Distributions received	(69,071)	(53,805)
Maximum exposure to loss	$ 89,635	$ 100,311

19. SUPPLEMENTAL INFORMATION ON OIL AND NATURAL GAS PRODUCING ACTIVITIES (UNAUDITED)

The Supplementary Information on Oil and Natural Gas Producing Activities is presented as required by the appropriate authoritative guidance. The supplemental information includes capitalized costs related to oil and natural gas producing activities; costs incurred for the acquisition of oil and natural gas producing activities, exploration and development activities and the results of operations from oil and natural gas producing activities.

Supplemental information is also provided for per unit production costs; oil and natural gas production and average sales prices; the estimated quantities of proved oil and natural gas reserves; the standardized measure of discounted future net cash flows associated with proved reserves and a summary of the changes in the standardized measure of discounted future net cash flows associated with proved reserves.

Costs

The following table sets forth our capitalized costs as of December 31, 2020 and 2019 (in thousands):

	December 31, 2020	December 31, 2019
Capitalized costs at the end of the period:[(a)]		
Oil and natural gas properties and related equipment (successful efforts method)		
Proved property	$ 112,471	$ 112,476
Less: Accumulated depreciation, depletion, amortization and impairments	(94,843)	(69,541)
Oil and natural gas properties and equipment, net	$ 17,628	$ 42,935

(a) Capitalized costs include the cost of equipment and facilities for our oil and natural gas producing activities. Proved property costs include capitalized costs for leaseholds holding proved reserves; development wells and related equipment and facilities (including uncompleted development well costs); and support equipment.

The following table sets forth costs incurred for oil and natural gas producing activities for the years ended December 31, 2020 and 2019 (in thousands):

	Years Ended December 31, 2020	Years Ended December 31, 2019
Costs incurred for the period:		
Development costs	$ —	$ 131
Oil and natural gas properties and equipment, net	$ —	$ 131

The development costs for the year ended December 31, 2019 primarily represent costs related to recompletions.

We had no exploration and dry hole costs in 2020 and 2019.

Results of Operations

The revenues and expenses associated directly with oil and natural gas producing activities are reflected in the Consolidated Statements of Operations. All of our oil and natural gas producing activities are located in the United States.

Net Proved Reserves of Natural Gas, NGLs and Oil

The following table sets forth information with respect to changes in proved developed and undeveloped reserves. All of our reserves are located in the United States.

	Total (MBoe)	Oil (MBoe)	Natural Gas (MBoe)	Natural Gas Liquids (MBoe)
Net proved reserves				
December 31, 2018	3,453	2,479	454	520
Revisions of previous estimates	(145)	(10)	(67)	(68)
Production	(309)	(228)	(39)	(42)
December 31, 2019	2,999	2,241	348	410
Revisions of previous estimates	(475)	(334)	(35)	(106)
Production	(241)	(191)	(26)	(24)
December 31, 2020	2,283	1,716	287	280
Proved developed reserves:				
December 31, 2019	2,999	2,241	348	410
December 31, 2020	2,283	1,716	287	280

Reserves and Related Estimates

Our estimate of proved reserves is based on the quantities of oil and natural gas that engineering and geological analyses demonstrate, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic parameters.

Our year end December 31, 2020 and 2019, proved reserve estimates were 2.3 MMBoe and 3.0 MMBoe, respectively. Reserve estimates for those periods were prepared by, Ryder Scott, an independent petroleum engineering firm, and are used for the applicable disclosures in our financial statements.

Our 2020 estimates of total proved reserves decreased 0.7 MMBoe from 2019 due to production of 0.2 MMBoe and revisions of previous estimates of 0.5 MMBoe. For proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $37.70 per Bbl for oil, $10.69 per Bbl for NGLs and $2.02 per Mcf for natural gas.

Our 2019 estimates of total proved reserves decreased 0.5 MMBoe from 2018 due to production of 0.3 MMBoe and revisions of previous estimates of 0.2 MMBoe. For proved reserves, the production weighted average product price over the remaining lives of the properties used in our reserve report were: $59.55 per Bbl for oil, $13.68 per Bbl for NGLs and $2.66 per Mcf for natural gas.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves, Including a Reconciliation of Changes Therein

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved oil and natural gas reserves. Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below.

Future cash inflows are calculated by applying the SEC-required prices of oil and natural gas relating to our proved reserves to the year-end quantities of those reserves. Future cash inflows exclude the impact of our hedging program. Future development and production costs represent the estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. In addition, asset retirement obligations are included within future production and development costs. There are no future income tax expenses because the Partnership is a non-taxable entity.

The assumptions used to compute estimated future cash inflows do not necessarily reflect expectations of actual revenues or costs or their present values. In addition, variations from expected production rates could result directly or indirectly from factors outside of our control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production; however, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

The following table summarizes the standardized measure of estimated discounted future cash flows from the oil and natural gas properties (in thousands):

	Years Ended December 31, 2020	Years Ended December 31, 2019
Future cash inflows	$ 71,161	$ 144,628
Future production costs	(50,809)	(80,007)
Future estimated development costs	(3,614)	(3,400)
Future net cash flows	16,738	61,221
10% annual discount for estimated timing of cash flows	(4,857)	(22,871)
Standardized measure of discounted estimated future net cash flows related to proved oil and natural gas reserves	$ 11,881	$ 38,350

The following table summarizes the principal sources of change in the standardized measure of estimated discounted future net cash flows (in thousands):

	Years Ended December 31, 2020	Years Ended December 31, 2019
Beginning of the period	$ 38,350	$ 52,246
Sales and transfers of oil and natural gas, net of production costs	(1,985)	(8,006)
Net changes in prices and production costs related to future production	(27,157)	(7,330)
Changes in development costs	(595)	35
Revisions of previous quantity estimates	(2,652)	(1,942)
Accretion discount	3,835	5,225
Change in production rates, timing, and other	2,085	(1,878)
Standardized measure of discounted future net cash flows related to proved oil and natural gas reserves	$ 11,881	$ 38,350

20. SUBSEQUENT EVENTS

On January 28, 2021, the Partnership received written notice of Stonepeak's election to receive distributions on the Class C Preferred Units for the quarter ended December 31, 2020 in common units. The aggregate distribution of 12,445,491 common units was made to Stonepeak Catarina on February 25, 2021, following the satisfaction of certain issuance conditions.

Exhibit 4.3

**DESCRIPTION OF THE REGISTRANT'S SECURITIES
REGISTERED PURSUANT TO SECTION 12 OF THE
SECURITIES EXCHANGE ACT OF 1934**

As of December 31, 2020, Evolve Transition Infrastructure LP (the "Partnership," "we" or "us") had a single class of security registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"): common units representing limited partner interests in the Partnership ("common units"). We also had a single Warrant Exercisable for Junior Securities (the "2019 Warrant") issued and outstanding, which is exercisable for Junior Securities, including common units.

The following description is a summary and does not purport to be complete. It is subject to and qualified in its entirety by reference to (i) the Third Amended and Restated Agreement of Limited Partnership of the Partnership (our "partnership agreement"), which is incorporated by reference as Exhibit 3.4 to the Annual Report on Form 10-K, of which this Exhibit 4.3 is a part, and (ii) the 2019 Warrant, which is incorporated by reference as Exhibit 10.29 to the Annual Report on Form 10-K of which this Exhibit 4.3 is a part. Please read and refer to the partnership agreement, the applicable provisions of the Delaware Act and the 2019 Warrant, for additional information. References to our "general partner," refer to Evolve Transition Infrastructure GP, LLC. Capitalized terms used but not defined herein have the meanings ascribed to them in the partnership agreement.

DESCRIPTION OF THE COMMON UNITS

The Common Units

The common units represent limited partner interests in us that entitle the holders thereof to the rights and privileges specified to limited partners set forth in our partnership agreement, including the right to participate in Partnership distributions.

Listing of Common Units

Our common units are traded on the NYSE American under the trading symbol "SNMP".

Transfer Agent and Registrar

Duties

Computershare Trust Company, N.A. serves as the registrar and transfer agent for the common units. We pay all fees charged by the transfer agent for transfers of common units except the following, which must be paid by our unitholders:

- surety bond premiums to replace lost or stolen certificates, taxes and other governmental charges;
- special charges for services requested by a holder of a common unit; and
- other similar fees or charges.

There is no charge to unitholders for disbursements of our cash distributions. We indemnify the transfer agent, its agents and each of their respective stockholders, directors, officers and employees against all claims and losses that may arise out of acts performed or omitted for their activities in that capacity, except for any liability due to any gross negligence or intentional misconduct of the indemnified person or entity.

Resignation or Removal

The transfer agent may resign, by notice to us, or be removed by us. The resignation or removal of the transfer agent will become effective upon our appointment of a successor transfer agent and registrar and its acceptance of the appointment. If no successor is appointed or a successor has not accepted its appointment, our general partner may act as the transfer agent and registrar until a successor is appointed.

Transfer of Common Units

Common units are “securities” as defined in the Securities Act, and are transferable according to the laws governing transfers of securities. In addition to the other rights acquired upon transfer, the transferee of the common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to enter into our partnership agreement;
- automatically becomes bound by the terms and conditions of our partnership agreement; and
- makes the consents, acknowledgement and waivers contained in our partnership agreement, all with or without the execution of the partnership agreement by such transferee.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of a common unit as the absolute owner. In that case, the beneficial holder’s rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Until a common unit has been transferred on our books, we and the transfer agent may treat the record holder of the common unit as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Number of Common Units

As of December 31, 2020, we had 19,953,880 common units issued and outstanding; 14,910,150 common units were held by the public; and 5,043,730 common units were held by affiliates of our general partner.

PROVISIONS OF OUR PARTNERSHIP AGREEMENT RELATING TO CASH DISTRIBUTIONS

Set forth below is a summary of the significant provisions of our partnership agreement that relate to cash distributions.

Cash Distribution Policy

Distributions of Available Cash

Our partnership agreement requires that, on or about the last day of each of February, May, August and November, we distribute all of our available cash to unitholders of record on the applicable record date. Available cash generally means, for any quarter, the sum of all cash and cash equivalents on hand at the end of that quarter:

- *less*, the amount of cash reserves established by our general partner to:
  - provide for the proper conduct of our business (including cash reserves for our future capital expenditures and anticipated future debt service requirements) subsequent to that quarter;
  - comply with applicable law, any of our debt instruments or other agreements; or

- provide funds for distributions to our unitholders for any one or more of the next four quarters (provided that our general partner may not establish cash reserves for distributions if the effect of the establishment of such reserves will prevent us from distributing the cash portion of any distributions on our Class C Preferred Units or minimum quarterly distribution on our common units with respect to such quarter);

- *plus*, if our general partner so determines, all or any portion of additional cash and cash equivalents on hand on the date of determination of available cash for the quarter resulting from working capital borrowings made subsequent to the end of such quarter.

The purpose and effect of the last bullet point above is to allow our general partner, if it so decides, to use cash from working capital borrowings made after the end of the quarter but on or before the date of determination of available cash for that quarter to pay distributions to unitholders. Under our partnership agreement, working capital borrowings are generally borrowings that are made under a credit facility, commercial paper facility or similar financing arrangement, and in all cases are used solely for working capital purposes or to pay distributions to unitholders, and with the intent of the borrower to repay such borrowings within twelve months with funds other than from additional working capital borrowings.

Class C Preferred Units

Under the terms of our partnership agreement, commencing with the quarter ended on June 30, 2019, the Class C Preferred Units receive a quarterly distribution of, at the election of the Board of Directors, (i) with respect to any distribution made with respect to the quarter ended June 30, 2019, 10.0% per annum if paid in full in cash or 12.0% per annum if paid in paid-in-kind units; (ii) with respect to any distribution made with respect to any quarter beginning with and after the quarter ending September 30, 2019, through and including the quarter ending December 31, 2021, 12.5% per annum, regardless of whether paid in cash, paid-in-kind units or a combination thereof; and (iii) with respect to any distribution made with respect to any quarter beginning on or after January 1, 2022, 14.0% per annum, regardless of whether paid in cash, paid-in-kind units or a combination thereof.

Additionally, under the terms of our partnership agreement, until the first quarter in which no Class C Preferred Units remain outstanding, we are not permitted to, and are prohibited from declaring or making, any distributions, redemptions or repurchases in respect of any Junior Securities, including common units, or any Parity Securities.

General Partner Interest and Incentive Distribution Rights

Our general partner currently owns a non-economic general partner interest in us which does not entitle it to receive cash distributions. However, our general partner may in the future own common units or other equity interests in us and will be entitled to receive distributions on any such interests.

SP Holdings, LLC ("SP Holdings"), the sole member of our general partner, holds all of our incentive distribution rights, which entitles it to receive increasing percentages, up to a maximum of 35.5%, of the available cash we distribute from operating surplus (as defined in our partnership agreement) after we have achieved the minimum quarterly distribution and the target distribution levels.

Percentage Allocation of Distributions from Operating Surplus

The following table illustrates the percentage allocation of distributions from operating surplus among our unitholders and SP Holdings (as the holder of our incentive distribution rights) at various distribution levels (1) pursuant to the distribution provisions of our partnership agreement, as well as (2) following a hypothetical reset of the target distribution levels based on the assumption that the quarterly distribution amount per common unit during the two fiscal quarters immediately preceding the reset election was $0.875.

Under our partnership agreement, our general partner has considerable discretion to determine the amount of available cash (as defined therein) for distribution each quarter to our unitholders, including discretion to establish cash reserves that would limit the amount of available cash eligible for distribution to our unitholders for any quarter. We do not guarantee that we will pay the target amount of the minimum quarterly distribution listed below (or any distributions at all) on our units in any quarter. The percentage interest set forth below for SP Holdings (1) assume that SP Holdings has not transferred its incentive distribution rights and (2) assume that we do not issue additional classes of equity securities. Additionally, as disclosed above under "—Class C Preferred Units" we are prohibited from making distributions to our common unitholders until the first quarter during which no Class C Preferred Units remain outstanding.

	Total Quarterly Distribution per Common Unit	Common Unitholders	SP Holdings
Minimum Quarterly Distribution	up to $0.50	100.0 %	0.0%
First Target Distribution	above $0.50 up to $0.575	100.0%	0.0%
Second Target Distribution	above $0.575 up to $0.625	87.0%	13.0%
Third Target Distribution	above $0.625 up to $0.875	77.0%	23.0%
Thereafter	above $0.875	64.5%	35.5%

Distributions of Cash Upon Liquidation

If we dissolve in accordance with our partnership agreement, we will sell or otherwise dispose of our assets in a process called liquidation. We will first apply the proceeds of liquidation to the payment of our creditors. We will distribute any remaining proceeds to the unitholders and the holders of the incentive distribution rights, in accordance with their capital account balances, as adjusted to reflect any gain or loss upon the sale or other disposition of our assets in liquidation. Any further net gain recognized upon liquidation will be allocated in a manner that takes into account the incentive distribution rights of SP Holdings.

Adjustments to Capital Accounts

We will make adjustments to capital accounts upon the issuance of additional units. In doing so, we generally will allocate any unrealized and, for tax purposes, unrecognized gain or loss resulting from the adjustments to the unitholders and the holders of our incentive distribution rights in the same manner as we allocate gain or loss upon liquidation.

1 DESCRIPTION OF OUR PARTNERSHIP AGREEMENT

The following is a summary of the material provisions of our partnership agreement. Please refer to our partnership agreement for additional information, which is incorporated by reference as an exhibit to the Annual Report on Form 10-K of which this Exhibit 4.3 is a part. We summarize the following provisions of our partnership agreement elsewhere herein:

- information relating to the rights and preferences of holders of common units in and to Partnership cash distributions is summarized under "Provisions of Our Partnership Agreement Relating to Cash Distributions" above; and

- information relating to the transfer of common units is summarized under "Description of the Common Units—Transfer of Common Units" above.

Capital Contributions

Unitholders are not obligated to make additional capital contributions, except as described below under "—Limited Liability."

Voting Rights

The following is a summary of the unitholder vote required for approval of the matters specified below. Matters that require the approval of a "unit majority" require the approval of a majority of the common units. Holders of Class C Preferred Units have voting rights identical to the voting rights of the common unitholders and vote together with the common units as a single class, such that the Class C Preferred Units (including, for the avoidance of doubt, the Class C Preferred PIK Units) will be entitled to one vote per Class C Preferred Unit, except that the Class C Preferred Units are entitled to vote as a separate class on any matter on which unitholders are entitled to vote that adversely affects the rights or preferences of the Class C Preferred Units in relation to other classes of partnership interests.

In voting their common units, our general partner and its affiliates will have no fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners.

Issuance of additional units	No approval right.
Amendment of the partnership agreement	Certain amendments may be made by our general partner without the approval of the unitholders. Other amendments generally require the approval of a unit majority. Please read "—Amendment of Our Partnership Agreement." In addition, amendments to the partnership agreement pertaining to the Class C Preferred Units requires the consent of each holder of a Class C Preferred Unit, to the extent such amendment would adversely affect such holder.
Merger of our partnership or the sale of all or substantially all of our assets	Unit majority in certain circumstances.
Dissolution of our partnership	Unit majority.
Continuation of our business upon dissolution	Unit majority.
Withdrawal of our general partner	Under most circumstances, the approval of a majority of the common units and Class C Preferred Units, excluding common units held by our general partner and its affiliates, is required for the withdrawal of our general partner prior to September 30, 2024 in a manner that would cause a dissolution of our partnership.
Removal of our general partner	Not less than 66 2/3% of the outstanding units, voting as a single class, including units held by our general partner and its affiliates.
Transfer of our general partner interest	No approval right.
Transfer of incentive distribution rights	No approval right.
Transfer of ownership interests in our general partner	No approval right.

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Evolve Transition Infrastructure GP LLC as our general partner or otherwise change our management. Please read “—Change of Management Provisions” and “—Meetings; Voting.”

Applicable Law; Forum, Venue and Jurisdiction

Our partnership agreement is governed by Delaware law. Our partnership agreement requires that any claims, suits, actions or proceedings:

- 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 limited partners or of limited partners to us, or the rights or powers of, or restrictions on, the limited partners or us);
- brought in a derivative manner on our behalf;
- asserting a claim of breach of a fiduciary duty owed by any director, officer or other employee of us or our general partner, or owed by our general partner, to us or the limited partners;
- asserting a claim arising pursuant to any provision of the Delaware Act; or
- asserting a claim governed by the internal affairs doctrine,

shall be exclusively brought in the Court of Chancery of the State of Delaware (or, if such court does not have subject matter jurisdiction thereof, any other court located in the State of Delaware with subject matter jurisdiction), in each case regardless of whether such claims, suits, actions or proceedings sound in contract, tort, fraud or otherwise, are based on common law, statutory, equitable, legal or other grounds, or are derivative or direct claims. In addition, each party to such claims, suits, actions or proceedings irrevocably waives the right to trial by jury.

Although we believe these provisions will benefit us by providing increased consistency in the application of Delaware law for the specific types of actions and proceedings, the provisions may have the effect of discouraging lawsuits against our directors, officers, employees and agents. The enforceability of similar forum selection provisions in other companies’ certificates of incorporation or similar governing documents have been challenged in legal proceedings, and it is possible that, in connection with one or more actions described above, a court could find that the forum selection provision contained in our partnership agreement is inapplicable or unenforceable in such action or actions, including with respect to claims arising under the federal securities laws. Limited partners will not be deemed, by operation of the forum selection provision alone, to have waived claims arising under the federal securities laws and the rules and regulations thereunder.

The forum selection provision is intended to apply “to the fullest extent permitted by applicable law” to the above-specified types of actions and proceedings, including, to the extent permitted by the federal securities laws, to lawsuits asserting both the above-specified claims and federal securities claims. However, application of the forum selection provision may in some instances be limited by applicable law. Section 27 of the Exchange Act provides: “The district courts of the United States ... shall have exclusive jurisdiction of violations of the Exchange Act or the rules and regulations thereunder, and of all suits in equity and actions at law brought to enforce any liability or duty created by the Exchange Act or the rules and regulations thereunder.” As a result, the forum selection provision will not apply to actions arising under the Exchange Act or the rules and regulations thereunder. However, Section 22 of the Securities Act provides for concurrent federal and state court jurisdiction over actions under the Securities Act and the rules and regulations thereunder, subject to a limited exception for certain “covered class actions” as defined in Section 16 of the Securities Act and interpreted by the courts. Accordingly, we believe that the forum selection provision would apply to actions arising under the Securities Act or the rules and regulations thereunder, except to the extent a particular action fell within the exception for covered class actions.

Limited Liability

Assuming that a limited partner does not participate in the control of our business within the meaning of the Delaware Act and that such limited partner otherwise acts in conformity with the provisions of our partnership agreement, that such limited partner's liability under the Delaware Act will be limited, subject to possible exceptions, to the amount of capital that such limited partner is obligated to contribute to us for that such limited partner's common units plus that such limited partner's share of any undistributed profits and assets. However, if it were determined that the right, or exercise of the right, by the limited partners as a group:

- to remove or replace our general partner;
- to approve some amendments to our partnership agreement; or
- to take other action under our partnership agreement

constituted "participation in the control" of our business for the purposes of the Delaware Act, then the limited partners could be held personally liable for our obligations under the laws of Delaware, to the same extent as our general partner. This liability would extend to persons who transact business with us under the reasonable belief that the limited partner is a general partner. Neither our partnership agreement nor the Delaware Act specifically provides for legal recourse against our general partner if a limited partner were to lose limited liability through any fault of our general partner. While this does not mean that a limited partner could not seek legal recourse, we know of no precedent for this type of a claim in Delaware case law.

Under the Delaware Act, a limited partnership may not make a distribution to a partner if, after the distribution, all liabilities of the limited partnership, other than liabilities to partners on account of their partnership interests and liabilities for which the recourse of creditors is limited to specific property of the partnership, would exceed the fair value of the assets of the limited partnership. For the purpose of determining the fair value of the assets of a limited partnership, the Delaware Act provides that the fair value of property subject to liability for which recourse of creditors is limited shall be included in the assets of the limited partnership only to the extent that the fair value of that property exceeds the nonrecourse liability. The Delaware Act provides that a limited partner who receives a distribution and knew at the time of the distribution that the distribution was in violation of the Delaware Act shall be liable to the limited partnership for the amount of the distribution for three years.

Limitations on the liability of members or limited partners for the obligations of a limited liability company or limited partnership have not been clearly established in many jurisdictions. If, by virtue of our ownership interest in our subsidiary or any subsidiaries we may have in the future, or otherwise, it were determined that we were conducting business in any jurisdiction without compliance with the applicable limited partnership or limited liability company statute, or that the right or exercise of the right by the limited partners as a group to remove or replace our general partner, to approve some amendments to our partnership agreement, or to take other action under our partnership agreement constituted "participation in the control" of our business for purposes of the statutes of any relevant jurisdiction, then the limited partners could be held personally liable for our obligations under the law of that jurisdiction to the same extent as our general partner under the circumstances. We will operate in a manner that our general partner considers reasonable and necessary or appropriate to preserve the limited liability of the limited partners.

Issuance of Additional Partnership Interests; Preemptive Rights

Our partnership agreement authorizes us to issue an unlimited number of additional partnership interests for the consideration and on the terms and conditions determined by our general partner without the approval of the unitholders.

It is possible that we will fund acquisitions through the issuance of additional common units or other partnership interests. Holders of any additional common units that we issue will be entitled to share equally with the then-existing common unitholders in our distributions. In addition, the issuance of additional common units or other partnership interests may dilute the value of the interests of the then-existing common unitholders in our net assets.

In accordance with Delaware law and the provisions of our partnership agreement, we may also issue additional partnership interests that, as determined by our general partner, may have rights to distributions or special voting rights to which the common units are not entitled. In addition, our partnership agreement does not prohibit our current or future subsidiaries from issuing equity interests, which may effectively rank senior to the common units.

The holders of our common units do not have preemptive rights to acquire additional common units or other partnership securities.

Amendment of Our Partnership Agreement

General

Amendments to our partnership agreement may be proposed only by our general partner. However, our general partner will have no duty or obligation to propose any amendment and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interests of us or the limited partners. In order to adopt a proposed amendment, other than the amendments discussed below, our general partner is required to seek written approval of the holders of the number of units required to approve the amendment or to call a meeting of the limited partners to consider and vote upon the proposed amendment. Except as described below, an amendment must be approved by a unit majority. In addition, amendments to our partnership agreement pertaining to the Class C Preferred Units requires the consent of holders of a majority of the outstanding Class C Preferred Units, voting separately as a class with one vote per Class C Preferred Unit, to the extent such amendment would adversely affect the Class C Preferred Units.

Prohibited Amendments

No amendment may be made that would:

- enlarge the obligations of any limited partner without his consent, unless approved by at least a majority of the type or class of limited partner interests so affected; or

- enlarge the obligations of, restrict, change or modify in any way any action by or rights of, or reduce in any way the amounts distributable, reimbursable or otherwise payable by us to our general partner or any of its affiliates without the consent of our general partner, which consent may be given or withheld in its sole discretion.

The provisions of our partnership agreement preventing the amendments having the effects described in the clauses above can be amended upon the approval of the holders of at least 75% of the outstanding units, voting as a single class (including units owned by our general partner and its affiliates).

No Unitholder Approval

Our general partner may generally make amendments to our partnership agreement without the approval of any limited partner to reflect:

- a change in our name, the location of our principal place of business, our registered agent or our registered office;

- the admission, substitution, withdrawal or removal of partners in accordance with our partnership agreement;

- a change that our general partner determines to be necessary or appropriate to qualify or continue our qualification as a limited partnership or other entity in which the limited partners have limited liability under the laws of any state or to ensure that neither we nor any of our subsidiaries will be treated as an association taxable as a corporation or otherwise taxed as an entity for U.S. federal income tax purposes (to the extent not already so treated or taxed);

- a change in our fiscal year or taxable year and related changes;

- an amendment that is necessary, in the opinion of our counsel, to prevent us or our general partner or its directors, officers, agents or trustees from in any manner being subjected to the provisions of the Investment Company Act of 1940, the Investment Advisers Act of 1940 or "plan asset" regulations adopted under the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), whether or not substantially similar to plan asset regulations currently applied or proposed;

- an amendment that our general partner determines to be necessary or appropriate in connection with the creation, authorization or issuance of additional partnership interests or the right to acquire partnership interests;

- any amendment expressly permitted in our partnership agreement to be made by our general partner acting alone;

- an amendment effected, necessitated or contemplated by a merger agreement that has been approved under the terms of our partnership agreement;

- any amendment that our general partner determines to be necessary or appropriate for the formation by us of, or our investment in, any corporation, partnership or other entity, as otherwise permitted by our partnership agreement;

- conversions into, mergers with or conveyances to another limited liability entity that is newly formed and has no assets, liabilities or operations at the time of the conversion, merger or conveyance other than those it receives by way of the conversion, merger or conveyance in certain circumstances; or

- any other amendments substantially similar to any of the matters described in the clauses above.

In addition, our general partner may make amendments to our partnership agreement, without the approval of any limited partner, if our general partner determines that those amendments:

- do not adversely affect the limited partners, considered as a whole, or any particular class of limited partners, in any material respect;

- are necessary or appropriate to satisfy any requirements, conditions or guidelines contained in any opinion, directive, order, ruling or regulation of any federal or state agency or judicial authority or contained in any federal or state statute;

- are necessary or appropriate to facilitate the trading of limited partner interests or to comply with any rule, regulation, guideline or requirement of any securities exchange on which the limited partner interests are or will be listed for trading;

- are necessary or appropriate for any action taken by our general partner relating to splits or combinations of units under the provisions of our partnership agreement;

- are necessary or appropriate in connection with the creation, authorization or issuance of any class or series of partnership securities; or

- are required to effect the intent of the provisions of our partnership agreement or are otherwise contemplated by our partnership agreement.

Opinion of Counsel and Unitholder Approval

Any amendment that our general partner determines adversely affects in any material respect one or more particular classes of limited partners will require the approval of at least a majority of the class or classes so affected, but no vote will be required by any class or classes of limited partners that our general partner determines are not adversely affected in any material respect. Any amendment that would have a material adverse effect on the rights or preferences of any type or class of outstanding units in relation to other classes of units will require the approval of at least a majority of the type or class of units so affected. Any amendment that would reduce the voting percentage required to take any action other than to remove the general partner or call a meeting of unitholders is required to be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the voting requirement sought to be reduced. Any amendment that would increase the percentage of units required to remove the general partner or call a meeting of unitholders must be approved by the affirmative vote of limited partners whose aggregate outstanding units constitute not less than the percentage sought to be increased. For amendments of the type not requiring unitholder approval, our general partner will not be required to obtain an opinion of counsel that an amendment will neither result in a loss of limited liability to the limited partners nor result in our being treated as a taxable entity for federal income tax purposes in connection with any of the amendments. Any amendment relating to special unitholder meetings, notices of unitholder meetings, quorum and voting requirements, actions without a meeting and the amendment provisions in our partnership agreement require approval of 75% of our outstanding units. No amendments to our partnership agreement, other than those the general partner can adopt without unitholder approval or in connection with a merger or consolidation, will become effective without the approval of holders of at least 90% of the outstanding units, voting as a single class, unless we first obtain an opinion of counsel to the effect that the amendment will not affect the limited liability under applicable law of any of our limited partners.

Merger, Consolidation, Conversion, Sale or Other Disposition of Assets

A merger, consolidation or conversion of us requires the prior consent of our general partner. However, our general partner will have no duty or obligation to consent to any merger, consolidation or conversion and may decline to do so free of any fiduciary duty or obligation whatsoever to us or the limited partners, including any duty to act in good faith or in the best interest of us or the limited partners.

In addition, our partnership agreement generally prohibits our general partner, without the prior approval of the holders of a unit majority, from causing us to sell, exchange or otherwise dispose of all or substantially all of our assets in a single transaction or a series of related transactions, including by way of merger, consolidation or other combination. Our general partner may, however, mortgage, pledge, hypothecate or grant a security interest in all or substantially all of our assets without such approval. Our general partner may also sell all or substantially all of our assets under a foreclosure or other realization upon those encumbrances without such approval. Finally, our general partner may consummate any merger without the prior approval of our unitholders if we are the surviving entity in the transaction, our general partner has received an opinion of counsel regarding limited liability and tax matters, the transaction would not result in a material amendment to the partnership agreement (other than an amendment that the general partner could adopt without the consent of other partners), each of our units will be an identical unit of our partnership following the transaction and the partnership securities to be issued do not exceed 20% of our outstanding partnership interests (other than incentive distribution rights) immediately prior to the transaction. If the conditions specified in our partnership agreement are satisfied, our general partner may convert us or any of our subsidiaries into a new limited liability entity or merge us or any of our subsidiaries into, or convey all of our assets to, a newly formed entity, if the sole purpose of that conversion, merger or conveyance is to effect a mere change in our legal form into another limited liability entity, we have received an opinion of counsel regarding limited liability and tax matters and the governing instruments of the new entity provide the limited partners and our general partner with the same rights and obligations as contained in our partnership agreement. Our unitholders are not entitled to dissenters' rights of appraisal under our partnership agreement or applicable Delaware law in the event of a conversion, merger or consolidation, a sale of substantially all of our assets or any other similar transaction or event.

Dissolution

We will continue as a limited partnership until dissolved and terminated under our partnership agreement and the Delaware Act. We will dissolve upon:

- the election of our general partner to dissolve us, if approved by the holders of units representing a unit majority;

- there being no limited partners, unless we are continued without dissolution in accordance with applicable Delaware law;

- the entry of a decree of judicial dissolution of our partnership;

- the withdrawal or removal of our general partner or any other event that results in its ceasing to be our general partner other than by reason of a transfer of its general partner interest in accordance with our partnership agreement or its withdrawal or removal following the approval and admission of a successor; or

- any other dissolution event as required by applicable Delaware law.

Upon a dissolution under the penultimate clause above, the holders of a unit majority may also elect, within specific time limitations, to continue our business on the same terms and conditions described in our partnership agreement by appointing as a successor general partner an entity approved by the holders of units representing a unit majority, subject to our receipt of an opinion of counsel to the effect that:

- the action would not result in the loss of limited liability under Delaware law of any limited partner; and

- neither we nor any of our subsidiaries would be treated as an association taxable as a corporation or otherwise be taxable as an entity for U.S. federal income tax purposes upon the exercise of that right to continue (to the extent not already so treated or taxed).

Liquidation and Distribution of Proceeds

Upon our dissolution, unless our business is continued, the liquidator authorized to wind up our affairs will, acting with all of the powers of our general partner that are necessary or appropriate, liquidate our assets and apply the proceeds of the liquidation as described in "Provisions of Our Partnership Agreement Relating to Cash Distributions—Distributions of Cash Upon Liquidation." The liquidator may defer liquidation or distribution of our assets for a reasonable period of time or distribute assets to partners in kind if it determines that a sale would be impractical or would cause undue loss to our partners.

Withdrawal or Removal of Our General Partner

Except as described below, our general partner has agreed not to withdraw voluntarily as our general partner prior to September 30, 2024 without obtaining the approval of the holders of at least a majority of the outstanding common units, excluding common units held by our general partner and its affiliates, and furnishing an opinion of counsel regarding limited liability and tax matters. On or after September 30, 2024, our general partner may withdraw as general partner without first obtaining approval of any unitholder by giving 90 days' written notice, and that withdrawal will not constitute a violation of our partnership agreement. Notwithstanding the information above, our general partner may withdraw without unitholder approval upon 90 days' notice to the limited partners if at least 50% of the outstanding common units are held or controlled by one person and its affiliates, other than our general partner and its affiliates. In addition, our partnership agreement permits our general partner to sell or otherwise transfer all of its general partner interest in us without the approval of the unitholders. Please read "—Transfer of General Partner Interest."

Upon withdrawal of our general partner under any circumstances, other than as a result of a transfer by our general partner of all or a part of its general partner interest in us, the holders of a unit majority may appoint a successor to that withdrawing general partner. If a successor is not elected, or is elected but an opinion of counsel regarding limited liability and tax matters cannot be obtained, we will be dissolved, wound up and liquidated, unless within a specified period after that withdrawal, the holders of a unit majority agree in writing to continue our business and to appoint a successor general partner. Please read “—Dissolution.”

Our general partner may not be removed unless that removal is approved by the vote of the holders of not less than 66 2/3% of the outstanding units, voting together as a single class, including units held by our general partner and its affiliates, and we receive an opinion of counsel regarding limited liability and tax matters. Any removal of our general partner is also subject to the approval of a successor general partner by the vote of a unit majority. Notwithstanding that Stonepeak, as the holder of all of our Class C Preferred Units held approximately 63.1% of our outstanding units as of December 31, 2019, it has agreed that until the earlier of the occurrence of a material breach of the partnership agreement by us or our general partner, and the date on which all of the Class C Preferred Units have been redeemed, without the prior written consent of the Board of Directors, it will not vote in favor of removing our general partner.

In the event of the removal of our general partner under circumstances where cause exists or withdrawal of our general partner where that withdrawal violates our partnership agreement, a successor general partner will have the option to purchase the general partner interest and incentive distribution rights of the departing general partner and its affiliates for a cash payment equal to the fair market value of those interests. Under all other circumstances where our general partner withdraws or is removed by the limited partners, the departing general partner will have the option to require the successor general partner to purchase the general partner interest and the incentive distribution rights of the departing general partner and its affiliates for fair market value. In each case, this fair market value will be determined by agreement between the departing general partner and the successor general partner. If no agreement is reached, an independent investment banking firm or other independent expert selected by the departing general partner and the successor general partner will determine the fair market value; if the departing general partner and the successor general partner cannot agree upon an expert, then an expert chosen by agreement of the experts selected by each of them will determine the fair market value.

If the option described above is not exercised by either the departing general partner or the successor general partner, then the departing general partner’s general partner interest and all of its affiliates’ incentive distribution rights will automatically convert into common units equal to the fair market value of those interests as determined by an investment banking firm or other independent expert selected in the manner described in the preceding paragraph.

In addition, we will be required to reimburse the departing general partner for all amounts due to the departing general partner, including, without limitation, all employee-related liabilities, including severance liabilities, incurred as a result of the termination of any employees employed for our benefit by the departing general partner or its affiliates.

Transfer of General Partner Interest

At any time, our general partner may transfer all or any of its general partner interest to another person without the approval of our common unitholders. As a condition of this transfer, the transferee must, among other things, assume the rights and duties of our general partner, agree to be bound by the provisions of our partnership agreement and furnish an opinion of counsel regarding limited liability and tax matters.

Transfer of Ownership Interests in the General Partner

At any time, the owners of our general partner may sell or transfer all or part of its ownership interests in our general partner to an affiliate or third-party without the approval of our unitholders.

Transfer of Incentive Distribution Rights

By transfer of incentive distribution rights in accordance with our partnership agreement, each transferee of incentive distribution rights will be admitted as a limited partner with respect to the incentive distribution rights transferred when such transfer and admission is reflected in our books and records. Each transferee:

- represents that the transferee has the capacity, power and authority to become bound by our partnership agreement;

- automatically becomes bound by the terms and conditions of our partnership agreement; and

- gives the consents, waivers and approvals contained in our partnership agreement.

Our general partner will cause any transfers to be recorded on our books and records no less frequently than quarterly.

We may, at our discretion, treat the nominee holder of incentive distribution rights as the absolute owner. In that case, the beneficial holder's rights are limited solely to those that it has against the nominee holder as a result of any agreement between the beneficial owner and the nominee holder.

Incentive distribution rights are securities and any transfers are subject to the laws governing transfer of securities. In addition to other rights acquired upon transfer, the transferor gives the transferee the right to become a limited partner for the transferred incentive distribution rights.

Until an incentive distribution right has been transferred on our books, we and the transfer agent may treat the record holder of the unit or right as the absolute owner for all purposes, except as otherwise required by law or stock exchange regulations.

Change of Management Provisions

Our partnership agreement contains specific provisions that are intended to discourage a person or group from attempting to remove Evolve Transition Infrastructure GP LLC as our general partner or from otherwise changing our management. Please read "—Withdrawal or Removal of Our General Partner" for a discussion of certain consequences of the removal of our general partner. If any person or group, other than our general partner and its affiliates, acquires beneficial ownership of 20% or more of any class of units, that person or group loses voting rights on all of its units. This loss of voting rights does not apply in certain circumstances. Please read "—Meetings; Voting."

Limited Call Right

If at any time our general partner and its controlled affiliates own more than 80% of the then-issued and outstanding limited partner interests of any class, our general partner will have the right, which it may assign and transfer in whole or in part to any of its affiliates or beneficial owners or to us, to acquire all, but not less than all, of the limited partner interests of the class held by unaffiliated persons, as of a record date to be selected by our general partner, on at least 10, but not more than 60, days' notice. The purchase price in the event of this purchase is the greater of:

- the highest price paid by our general partner or any of its affiliates for any limited partner interests of the class purchased within the 90 days preceding the date on which our general partner first mails notice of its election to purchase those limited partner interests; and

- the average of the daily closing prices of the partnership securities of such class over the 20 consecutive trading days preceding the date that is three days before the date the notice is mailed.

As a result of our general partner's right to purchase outstanding limited partner interests, a holder of limited partner interests may have his limited partner interests purchased at an undesirable time or at a price that may be lower than market prices at various times prior to such purchase or lower than a unitholder may anticipate the market price to be in the future. The tax consequences to a unitholder of the exercise of this call right are the same as a sale by that unitholder of his common units in the market.

Possible Redemption of Ineligible Holders

Non-Taxpaying Holders; Redemption

To avoid any adverse effect on the maximum applicable rates chargeable to customers by us or any of our future subsidiaries, or in order to reverse an adverse determination that has occurred regarding such maximum rate, our partnership agreement provides our general partner the power to amend the agreement. If our general partner, with the advice of counsel, determines that our not being treated as an association taxable as a corporation or otherwise taxable as an entity for U.S. federal income tax purposes, coupled with the tax status (or lack of proof thereof) of one or more of our limited partners, has, or is reasonably likely to have, a material adverse effect on the maximum applicable rates chargeable to customers by us or our subsidiaries, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or appropriate to:

- obtain proof of the U.S. federal income tax status of our limited partners (and their owners, to the extent relevant); and

- permit us to redeem the units held by any person whose tax status has or is reasonably likely to have a material adverse effect on the maximum applicable rates or who fails to comply with the procedures instituted by our general partner to obtain proof of the federal income tax status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Non-Citizen Assignees; Redemption

If our general partner, with the advice of counsel, determines that we are subject to U.S. federal, state or local laws or regulations that create a substantial risk of cancellation or forfeiture of any property that we have an interest in because of the nationality, citizenship or other related status of any limited partner, then our general partner may adopt such amendments to our partnership agreement as it determines necessary or advisable to:

- obtain proof of the nationality, citizenship or other related status of our limited partners (and their beneficial owners, to the extent relevant); and

- permit us to redeem the units held by any person whose nationality, citizenship or other related status creates substantial risk of cancellation or forfeiture of any property or who fails to comply with the procedures instituted by the general partner to obtain proof of the nationality, citizenship or other related status. The redemption price in the case of such a redemption will be the average of the daily closing prices per unit for the 20 consecutive trading days immediately prior to the date set for redemption.

Meetings; Voting

Except as described below regarding a person or group owning 20% or more of any class of units then outstanding, record holders of units on an applicable record date will be entitled to notice of, and to vote at, meetings of our limited partners and to act upon matters for which approvals may be solicited.

Our general partner does not anticipate that any meeting of our unitholders will be called in the foreseeable future. Any action that is required or permitted to be taken by the unitholders may be taken either at a meeting of the unitholders or without a meeting if consents in writing describing the action so taken are signed by holders of the number of units necessary to authorize or take that action at a meeting. Meetings of the unitholders may be called by our general partner or by unitholders owning at least 20% of the outstanding units of the class for which a meeting is proposed. Unitholders may vote either in person or by proxy at meetings. The holders of a majority of the outstanding units of the class or classes for which a meeting has been called, represented in person or by proxy, will constitute a quorum, unless any action by the unitholders requires approval by holders of a greater percentage of the units, in which case the quorum will be the greater percentage.

Each record holder of a unit has a vote according to his percentage interest in us, although additional limited partner interests having special voting rights could be issued. Please read "—Issuance of Additional Interests." However, if at any time any person or group, other than our general partner and its affiliates, or a direct or subsequently approved transferee of our general partner or its affiliates and purchasers specifically approved by our general partner, acquires, in the aggregate, beneficial ownership of 20% or more of any class of units then outstanding (other than any class of the Class C Preferred Units), that person or group will lose voting rights on all of its units and the units may not be voted on any matter and will not be considered to be outstanding when sending notices of a meeting of unitholders, calculating required votes, determining the presence of a quorum or for other similar purposes. This loss of voting rights does not apply (i) to any person or group that acquires the units directly from our general partner or its affiliates, (ii) to any transferees of that person or group approved by our general partner, (iii) to any person or group who acquires the units with the specific prior approval of our general partner, (iv) Stonepeak with respect to its ownership (beneficial or recorded) of the Class C Preferred Units or (v) the holder of the 2019 Warrant with respect to the Junior Securities issued or issuable upon exercise of the 2019 Warrant. In addition, if any person or group beneficially owns 20% or more of any class of units solely as a result of actions taken by us, then the 20% threshold is increased, with respect to such person, to a percentage equal to such person's new beneficial ownership after the taking of such action plus the difference between 20% and such person's beneficial ownership prior to such action. Common units held in nominee or street name account will be voted by the broker or other nominee in accordance with the instruction of the beneficial owner unless the arrangement between the beneficial owner and his nominee provides otherwise.

Any notice, demand, request, report or proxy material required or permitted to be given or made to record common unitholders under our partnership agreement will be delivered to the record holder by us or by the transfer agent.

Voting Rights of Incentive Distribution Rights

If a majority of the incentive distribution rights are held by our general partner and its affiliates, the holders of the incentive distribution rights will have no right to vote in respect of such rights on any matter, unless otherwise required by law, and the holders of the incentive distribution rights shall be deemed to have approved any matter approved by our general partner.

If less than a majority of the incentive distribution rights are held by our general partner and its affiliates, the incentive distribution rights will be entitled to vote on all matters submitted to a vote of unitholders, other than amendments and other matters that our general partner determines do not adversely affect the holders of the incentive distribution rights in any material respect. On any matter in which the holders of incentive distribution rights are entitled to vote, such holders will vote together with the common units as a single class, and such incentive distribution rights shall be treated in all respects as common units when sending notices of a meeting of our limited partners to vote on any matter (unless otherwise required by law), calculating required votes, determining the presence of a quorum or for other similar purposes under our partnership agreement. The relative voting power of the holders of the incentive distribution rights and the common units will be set in the same proportion as cumulative cash distributions, if any, in respect of the incentive distribution rights for the four consecutive quarters prior to the record date for the vote bears to the cumulative cash distributions in respect of such class of units for such four quarters.

Status as Limited Partner

By transfer of common units in accordance with our partnership agreement, each transferee of common units shall be admitted as a limited partner with respect to the common units transferred when such transfer and admission are reflected in our books and records. Except as described under "—Limited Liability," the common units and the Class C Preferred Units will be fully paid, and unitholders will not be required to make additional contributions.

Indemnification

Under our partnership agreement, in most circumstances, we will indemnify the following persons, to the fullest extent permitted by law, from and against all losses, claims, damages or similar events:

- our general partner;
- any departing general partner;
- any person who is or was an affiliate of our general partner or any departing general partner;
- any person who is or was a manager, managing member, general partner, director, officer, employee, agent, fiduciary or trustee of our partnership, our subsidiaries, our general partner, any departing general partner or any of their affiliates;
- any person who is or was serving at the request of a general partner, any departing general partner or any of their respective affiliates as a manager, managing member, general partner, director, officer, employee, agent, fiduciary or trustee of another person owing a fiduciary duty to us or our subsidiaries;
- any person who controls our general partner or any departing general partner; and
- any person designated by our general partner.

Any indemnification under these provisions will only be out of our assets. Unless our general partner otherwise agrees, it will not be personally liable for, or have any obligation to contribute or lend funds or assets to us to enable us to effectuate, indemnification. We may purchase insurance against liabilities asserted against and expenses incurred by persons for our activities, regardless of whether we would have the power to indemnify the person against liabilities under our partnership agreement.

Reimbursement of Expenses

Our partnership agreement requires us to reimburse our general partner and its affiliates for all direct and indirect expenses they incur or payments they make on our behalf and all other expenses allocable to us or otherwise incurred by our general partner and its affiliates in connection with operating our business. Our partnership agreement does not set a limit on the amount of expenses for which our general partner and its affiliates may be reimbursed. These expenses may include salary, bonus, incentive compensation and other amounts paid to persons who perform services for us or on our behalf and expenses allocated to our general partner by its affiliates. Our general partner is entitled to determine in good faith the expenses that are allocable to us.

Books and Reports

Our general partner is required to keep appropriate books of our business at our principal offices. These books will be maintained for both tax and financial reporting purposes on an accrual basis. For tax and fiscal reporting purposes, our fiscal year is the calendar year.

We will furnish or make available to record holders of our common units, within 105 days after the close of each fiscal year, an annual report containing audited consolidated financial statements and a report on those consolidated financial statements by our independent registered public accounting firm. Except for our fourth quarter, we will also furnish or make available summary financial information within 50 days after the close of each quarter. We will be deemed to have made any such report available if we file such report with the SEC on EDGAR or make the report available on a publicly available website which we maintain.

We will furnish each record holder with information reasonably required for U.S. federal and state tax reporting purposes within 90 days after the close of each calendar year. This information is expected to be furnished in summary form so that some complex calculations normally required of partners can be avoided. Our ability to furnish this summary information to our unitholders will depend on their cooperation in supplying us with specific information. Every unitholder will receive information to assist him in determining his U.S. federal and state tax liability and in filing his U.S. federal and state income tax returns, regardless of whether he supplies us with the necessary information.

Right to Inspect Our Books and Records

Our partnership agreement provides that a limited partner can, for a purpose reasonably related to his interest as a limited partner, upon reasonable written demand stating the purpose of such demand and at his own expense, have furnished to him:

- a current list of the name and last known address of each record holder;
- information as to the amount of cash, and a description and statement of the agreed value of any other capital contribution, contributed or to be contributed by each partner and the date on which each became a partner;
- copies of our partnership agreement, our certificate of limited partnership, related amendments and powers of attorney under which they have been executed;
- information regarding the status of our business and financial condition (provided that obligation shall be satisfied to the extent the limited partner is furnished our most recent annual report and any subsequent quarterly or periodic reports required to be filed (or which would be required to be filed) with the SEC pursuant to Section 13(a) of the Exchange Act); and
- any other information regarding our affairs that our general partner determines is just and reasonable.

Under our partnership agreement, however, each of our limited partners and other persons who acquire interests in our partnership interests do not have rights to receive information from us or any of the persons we indemnify as described above under "—Indemnification" for the purpose of determining whether to pursue litigation or assist in pending litigation against us or those indemnified persons relating to our affairs, except pursuant to the applicable rules of discovery relating to the litigation commenced by the person seeking information.

Our general partner may, and intends to, keep confidential from the limited partners trade secrets or other information the disclosure of which our general partner believes in good faith is not in our best interests or that we are required by law or by agreements with third parties to keep confidential.

Registration Rights

Under our partnership agreement, we have agreed to register for resale under the Securities Act and applicable state securities laws any common units or other limited partner interests proposed to be sold by our general partner or any of its affiliates or their assignees if an exemption from the registration requirements is not otherwise available. These registration rights continue for two years following any withdrawal or removal of our general partner. We are obligated to pay all expenses incidental to the registration, excluding underwriting discounts.

On November 22, 2016, we entered into a registration rights agreement with SN UR Holdings, LLC, and agreed to register the common units issued to such person on such date in connection with a private placement of our common units.

On August 2, 2019, we entered into an amended and restated registration rights agreement with Stonepeak and agreed to register the common units issuable to Stonepeak upon exercise of the 2019 Warrant.

DESCRIPTION OF 2019 WARRANT

On August 2, 2019, we issued the 2019 Warrant to Stonepeak. The 2019 Warrant entitles the holder to receive a number of each class of Junior Securities representing ten percent (10%) of the Junior Securities Deemed Outstanding (as defined in the 2019 Warrant) of such class as of the date the 2019 Warrant is exercised.

The 2019 Warrant is exercisable until the later of August 2, 2026 or the thirtieth (30th) calendar day following the date on which all of the Class C Preferred Units are redeemed by us. There is no exercise price payable in connection with the exercise of the 2019 Warrant. As a result of the 2019 Warrant having no exercise price, the 2019 Warrant does not contain any provisions for changes to or adjustments in the exercise price.

In the event of any (i) capital reorganization of the Partnership, (ii) reclassification of Partnership interests (other than a change as a result of a unit dividend or subdivision, split-up or combination of units), (iii) consolidation or merger of the Partnership with or into another Person, (iv) sale of all or substantially all of the Partnership's assets to another Person or (v) other similar transaction, in each case which entitles the holders of Junior Securities other than Excluded Junior Securities (as defined in the 2019 Warrant) to receive (either directly or upon subsequent liquidation) units, securities or assets with respect to or in exchange for such class of Junior Securities (each such transaction, an "Adjustment Transaction"), the 2019 Warrant shall, immediately after such Adjustment Transaction, remain outstanding and shall thereafter, in lieu of or in addition to (as the case may be) the number of Warrant Units (as defined in the 2019 Warrant) then exercisable under the 2019 Warrant, be exercisable for the kind and number of units or other securities or assets of the Partnership or of the successor Person resulting from such transaction to which the holder would have been entitled upon such Adjustment Transaction if the Holder had exercised the 2019 Warrant in full immediately prior to the time of such Adjustment Transaction and acquired the applicable number of Warrant Units then issuable hereunder as a result of such exercise.

Executive Officer Compensation

Base Salary

The following table sets forth the base salary for each named executive officer of Evolve Transition Infrastructure GP LLC, the general partner of Evolve Transition Infrastructure LP (the "Partnership"). Each person is an employee of SNMP Services Inc. ("Services") and provides services to the Partnership, with the amounts listed being the portion of the salary allocated to the Partnership, effective as of January 1, 2021.

Sanchez Production Partners LP, Officer	**Base Salary**
Gerald F. Willinger *Chief Executive Officer*	$600,000
Charles C. Ward *Chief Financial Officer & Secretary*	$375,000

Other Benefits

Services does not maintain a defined benefit pension plan for its employees because it believes that such plans primarily reward longevity rather than performance. Services provides a basic benefits package generally to all employees, which includes a 401(k) plan, parking costs, and health, disability and life insurance. In its discretion, Services and/or the board of directors of the Partnership's general partner may award the named executive officers cash bonuses and/or equity compensation.

Exhibit 10.14

Board Compensation for Directors*

Type of Compensation	Amount
Board Cash Retainer+	Fiscal 2020: $35,000, payable quarterly on the last day of each fiscal quarter, commencing January 1, 2020+
Board Meeting Fees	$1,500 for each meeting attended
Committee Meeting Fees	$1,000 for each substantive meeting of the Audit Committee attended
	$3,500 for each substantive meeting of the Conflicts Committee attended
Committee Chair Retainer	$3,500 for Audit Committee Chair, payable quarterly on the last day of each fiscal quarter+
	$2,500 for Conflicts Committee Chair, payable quarterly on the last day of each fiscal quarter+
Other Benefits	Independent Directors are eligible to participate in a basic health benefits package similar to that available to Evolve employees.

* Includes all persons serving as Independent Directors as of the beginning of each quarterly period.

\+ For any person who ceases to serve during the fiscal quarter prior to such payment date, such person shall receive a pro rata amount for the portion of the fiscal quarter so served.

EXECUTIVE SERVICES AGREEMENT

THIS EXECUTIVE SERVICES AGREEMENT (this "Agreement") is made and entered into as of August 2, 2019 (the "Effective Date"), by and between Charles C. Ward ("Executive") and Sanchez Midstream Partners GP LLC, a Delaware limited liability company ("Company") and the general partner of Sanchez Midstream Partners LP, a Delaware limited partnership ("Partnership," and together with Company, the "Partnership Parties"). Executive and Company are collectively referred to herein as the "Parties," and individually as a "Party."

WHEREAS, Executive is the Chief Financial Officer and Secretary of the Company and provides services for and on behalf of the Partnership Parties; and

WHEREAS, the Parties wish to memorialize their agreement with respect to the terms and conditions of Executive's continued employment as the Chief Financial Officer and Secretary of the Company.

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties, intending to be legally bound, mutually agree as follows:

1. Term: Executive agrees to continue to provide services for the Partnership Parties and the Company agrees to continue to engage Executive to serve as the Company's Chief Financial Officer and Secretary, pursuant to the terms and conditions of this Agreement and continuing until Executive's services are terminated by either Executive or the Company, as applicable, in accordance with Section 4 below (the "Term").

2. Place of Services: Executive will perform his duties under this Agreement at the Partnership Parties' offices in Houston, Texas.

3. Compensation: During the Term of this Agreement, the Company agrees as follows:

(a) Base Salary: Executive's annual base salary is $375,000, subject to applicable withholdings and deductions (the "Base Salary"). Executive's Base Salary may not be decreased during the Term of this Agreement by the Company, but may be increased in the absolute discretion of the Company's Board of Directors (the "Board"), or, if applicable, an authorized committee thereof, in accordance with the rules and procedures governing the Board. To the extent Executive's Base Salary is increased during the Term, such increased rate shall thereafter be considered Executive's "Base Salary" for purposes of this Agreement.

(b) Annual Bonus: In addition to Executive's Base Salary, during the Term Executive shall continue to receive an annual cash bonus for services rendered by Executive to the Partnership Parties equal to an amount between seventy-five percent (75%) and one hundred twenty-five percent (125%) of Executive's Base Salary, as determined by the Board, in its sole discretion, subject to applicable withholdings and deductions (the "Annual Bonus"). Fifty percent (50%) of the Annual Bonus shall be payable to Executive no later than September 30 of the year for which such Annual Bonus relates, and the remainder of the Annual Bonus, including any true-up and changes determined by the Board, in its sole discretion, shall be payable to Executive no later than March 31 of the year following the year for which such Annual Bonus relates. For the avoidance of doubt, fifty percent (50%) of Executive's Annual Bonus for fiscal 2019 shall be paid no later than September 30, 2019 and the remainder of such Annual Bonus shall be paid no later than March 31, 2020 and shall include any amounts approved as part of the Annual Bonus by the Board. Executive's Annual Bonus shall be determined in a manner and utilizing a qualitative assessment of financial and individual performance achievements consistent with the determination of Executive's Annual Bonus in prior years; provided, that, the Annual Bonus may not be decreased by the Company during the term of this Agreement, but may be increased in the absolute discretion of the Board, or, if applicable, an authorized committee thereof, in accordance with the rules and procedures governing the Board. To the extent Executive's Annual Bonus is increased during the Term, such increased rate shall thereafter be considered Executive's "Annual Bonus" for purposes of this Agreement.

(c) Long-Term Incentive Compensation Awards: Executive shall be eligible to receive awards under the Sanchez Midstream Partners LP Long-Term Incentive Plan or any successor thereto (the "Plan") and to participate in any long-term incentive programs available generally to the Company's executive officers in the future, both as determined in the sole discretion of the Board, or, if applicable, a committee thereof.

(d) Additional Bonus. If, as of the date that an award under the Plan (or other applicable long-term incentive program of the Company) as described in Section 3(c) above would otherwise be granted, (i) either (1) the common units representing limited partner interests in the Partnership ("Common Units") are no longer publicly traded on (A) any exchange registered with the Securities and Exchange Commission (the "SEC") under Section 6(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") (or any successor to such Section), or (B) any other securities exchange (whether or not registered with the SEC under Section 6(a) (or any successor to such Section) of the Exchange Act) that the Company shall designate as a "National Securities Exchange" for purposes of the Partnership Agreement or the Partnership has otherwise been delisted, (2) the Board has made a public announcement that the Partnership will no longer make cash distributions on the Common Units, or (3) the Board has made a formal determination in writing that no cash distributions will be made on the Common Units for the first quarter of the applicable calendar year, and (ii) as a result of the event(s) described in clause (i), the Board (or the applicable committee) in its discretion elects not to grant any award to the Executive under the Plan (or other applicable long-term incentive program) pursuant to paragraph (c) above, then the Executive will be entitled to an additional cash bonus award, in an amount to be determined by the Board in its discretion and which shall be paid to the Executive at the same time the Annual Bonus is paid (each such additional cash bonus award, an "Additional Bonus"). Notwithstanding the foregoing, no bonus shall be paid in substitution for compensation subject to (and not exempt from) Section 409A of the Code, to the extent such payment would result in the imposition of additional tax, interest and/or penalties upon Executive under Section 409A of the Code.

4. Termination

(a) Services Terminable At-Will; Notice of Termination: The Term and Executive's appointment as an officer of the Company may be terminated by Executive or the Company at any time and for any reason; provided, that, any purported termination by Executive or the Company shall be communicated by a written "Notice of Termination" to the other in accordance with Section 18 below. The Notice of Termination shall (i) indicate the specific termination provision of this Agreement relied upon, (ii) to the extent applicable, set forth in reasonable detail the facts and circumstances claimed to provide a basis for the termination of Executive's services, under the provision so indicated, and (iii) specify the effective "Termination Date" of Executive's services to the Partnership Parties (which shall not be earlier than the date the Notice of Termination is sent, and shall not be later than thirty (30) days after the date of the Notice of Termination is sent).

(b) Definitions: For purposes of this Agreement, the following definitions shall apply:

(i) Affiliate: means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

(ii) Cause: the Company will have "Cause" to terminate Executive's services under this Agreement for any of the following reasons:

(A) Executive's conviction of, or plea of nolo contendere to, any felony or crime involving moral turpitude in connection with the performance of his duties to the Partnership Parties;

(B) Executive being charged with, or a defendant in, an action brought by the SEC or another federal or state regulator based primarily on Executive's individual alleged acts or omissions during Executive's appointment as an officer of, or while providing services to, the Partnership Parties;

(C) Executive's commission of a willful and material act of fraud or embezzlement of the Company's funds or other assets causing material damage to the Company; or

(D) Executive's willful and material misrepresentations or concealments on any written reports submitted to the Board;

provided, that, any of the events described in Section 4(b)(ii)(C) or Section 4(b)(ii)(D) above shall constitute Cause only if Executive fails to cure such event to the reasonable satisfaction of the Board within thirty (30) calendar days of receiving written notice from the Board of the event which allegedly constitutes Cause; and provided further that a termination shall not be deemed to be for Cause under Section 4(b)(ii)(C) or Section 4(b)(ii)(D) unless and until there shall have been delivered to Executive a copy of a resolution duly adopted by the affirmative vote of a majority of the members of the Board (other than Executive), at a meeting of the Board called and held for such purpose (after reasonable notice is provided to Executive, and Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, Executive is guilty of the conduct described in Section 4(b)(ii)(C) or Section 4(b)(ii)(D), above, and specifying the particulars thereof in detail.

For the purposes of this provision, no act or failure to act on the part of Executive shall be considered "willful" unless it is done, or omitted to be done, by Executive in bad faith and without reasonable belief that Executive's actions or omission was in the best interests of the Partnership Parties. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board, or upon the instructions of the Board, or based upon the advice of counsel for the Company, shall be conclusively presumed to be done, or omitted to be done, by Executive in good faith and in the best interests of the Partnership Parties.

(iii) Change in Control: means the occurrence of any of the following events: (A) the Company withdraws or is removed as the general partner of the Partnership, (B) the Company transfers any portion of its general partner interest in the Partnership to any Person other than an Affiliate of the Company, (C) any merger, consolidation or other transaction involving the Partnership or the Company and another Person (other than an Affiliate thereof), whether in one or a series of related transactions, which results in one or more Persons directly or indirectly acquiring control over more than fifty percent (50%) of the equity interests of the Partnership or the Company, as applicable, (D) the direct or indirect sale, transfer, conveyance or other disposition, in one or a series of related transactions, of all or substantially all of the assets of the Partnership, (E) any dissolution or liquidation of the Partnership or the Company (other than in connection with a bankruptcy proceeding or a statutory winding up); or (F) any other transaction pursuant to which the Company or any Affiliate controlled by the Company exercises its rights to purchase all of the Partnership's common units representing limited partner interests ("Common Units") pursuant to Section 15.1 of the Agreement of Limited Partnership of the Partnership, as amended (the "Partnership Agreement").

(iv) Common Unit Price: means (A) if the consideration to be received in the Change in Control by the holders of Common Units is solely cash, the amount of cash consideration per Common Unit or (B) if the consideration to be received in the Change in Control by holders of Common Units is other than solely cash (1) the average of the closing sale prices per Common Unit (or, if no closing sale price is reported, the average of the closing bid and ask prices or, if more than one in either case, the average of the average closing bid and the average closing ask prices) for the ten (10) consecutive trading days immediately preceding, but not including, the effective date of the Change in Control as reported on the principal U.S. securities exchange on which the Common Units are then traded, or (2) the average of the last quoted bid prices for the Common Units in the over-the-counter market as reported by OTC Market Group Inc. or similar organization for the ten (10) consecutive trading days immediately preceding, but not including, the effective date of the Change in Control, if the Common Units are not then listed for trading on a U.S. securities exchange.

(v) Good Reason: Executive will have "Good Reason" to terminate his appointment as an officer of the Company under this Agreement for any of the following reasons to which Executive does not consent in writing:

(A) the relocation of Executive's primary place of performing services for the Partnership Parties to a location more than fifty (50) miles from Executive's primary place of performing services as set forth in Section 2;

(B) a material diminution in Executive's Base Salary;

(C) a material diminution in the authority, duties or responsibilities of Executive to the Partnership Parties; or

(D) any other action or inaction that constitutes the Company's material breach of any provision of this Agreement;

provided, that, any of the conditions described in Section 4(b)(v)(A) through 4(b)(v)(D) above shall constitute Good Reason only if the Company fails to cure such condition to the reasonable satisfaction of Executive within thirty (30) calendar days of receiving written notice from Executive of the condition which allegedly constitutes Good Reason; and provided further, that, Executive's termination shall constitute a termination by Executive for Good Reason only if the Termination Date occurs not later than ninety (90) calendar days following the initial existence of one or more of the conditions described in Section 4(b)(v)(A) through 4(b)(v)(D) above.

(vi) Disability: For purposes of this Agreement, "Disability" shall mean the earlier of:

(A) a written determination by a physician that Executive has been unable to substantially perform his usual and customary services for the Partnership Parties under this Agreement for a period of at least one hundred twenty (120) consecutive days (or one hundred eighty (180) non-consecutive days) during any twelve (12) month period as a result of Executive's incapacity due to mental or physical illness; or

(B) "disability" as such term is defined in the Company's applicable long-term disability insurance plan as it is in effect at the time Executive becomes Disabled.

(vii) Person: means any individual, corporation, limited liability company, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof, or other entity.

(c) Compensation Upon Certain Events.

(i) Termination by the Company for Cause or by Executive Without Good Reason: If Executive's appointment as an officer of the Company hereunder is terminated by the Company for Cause or by Executive without Good Reason, then::

(A) Company shall pay to Executive an amount equal to Executive's accrued but unpaid then-current Base Salary through the Termination Date, and

(B) the treatment of each long-term incentive compensation award shall be governed by the terms and conditions of the applicable award agreement for such award and the Plan or similar incentive award program under which such award was granted.

(ii) Termination Upon Executive's Death or Disability: Upon Executive's death or Disability:

(A) Company shall pay to Executive (or his designated beneficiaries), an amount equal to Executive's accrued but unpaid then-current Base Salary through the Termination Date;

(B) to the extent not yet paid to Executive (or his designated beneficiaries), Company shall pay to Executive (or his designated beneficiaries) (1) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (2) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(C) any units which may have been awarded to Executive under the Plan or any other long-term incentive programs available generally to the Company's executive officers in the future, in each case, shall vest in full as of the Termination Date and convert into Common Units as set forth in the applicable award agreement.

(iii) Termination by the Company Without Cause or by Executive for Good Reason: If Executive's appointment as an officer of the Company hereunder is terminated by the Company without Cause, or by Executive for Good Reason, then:

(A) Company shall pay to Executive an amount equal to (1) two hundred percent (200%) of Executive's Base Salary; *plus* (2) two hundred percent (200%) of the largest Annual Bonus (including the amount of any Additional Bonus, if applicable) paid to (or due to be paid to) Executive for the year in which the Termination Date occurred or any year in the three (3)-calendar year period immediately preceding the Termination Date, which shall be paid in a single lump sum within fourteen (14) calendar days of the Termination Date;

(B) if Executive timely elects continuation coverage under COBRA, then the Company shall pay the COBRA premiums for Executive and his eligible dependents directly to the applicable insurer(s) during the COBRA continuation period;

(C) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date, an amount equal to all outstanding amounts owed to Executive for services performed by Executive for or on behalf of the Partnership Parties, including, without limitation, (1) the amount of Executive's accrued but unpaid then current Base Salary through the Termination Date, and (2) to the extent not yet

paid to Executive, (a) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (b) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(D) any units which may have been awarded to Executive under the Plan or any other long-term incentive programs available generally to the Company's executive officers in the future, in each case, shall vest in full as of the Termination Date and convert into Common Units as set forth in the applicable award agreement.

(iv) <u>Change in Control</u>: If, during the period beginning sixty (60) days prior to and ending two (2) years immediately following a Change in Control, either (A) Company terminates the Executive's employment without Cause, (B) the Executive's death occurs, (C) the Executive becomes Disabled, or (D) the Executive terminates his employment with Company for any reason, in each case constituting a "separation from service" within the meaning of Section 409A of the Internal Revenue Code of 1986 (the "<u>Code</u>") ("<u>Separation from Service</u>"), then:

(A) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date: an amount equal to (1) two hundred percent (200%) of Executive's then-current Base Salary; *plus* (2) two hundred percent (200%) of the largest Annual Bonus (including the amount of any Additional Bonus, if applicable) paid to (or due to be paid to) Executive for the year in which the Termination Date occurred or any year in the three calendar year period immediately preceding the Termination Date;

(B) if Executive timely elects continuation coverage under COBRA, then Company shall pay the COBRA premiums for Executive and his eligible dependents directly to the applicable insurer(s) during the COBRA continuation period;

(C) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date, an amount equal to all outstanding amounts owed to Executive for services performed by Executive for or on behalf of the Partnership Parties, including, without limitation, (1) the amount of Executive's accrued but unpaid then current Base Salary through the Termination Date, and (2) to the extent not yet

paid to Executive, (a) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (b) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(D) any units which may have been awarded to Executive under the Plan shall vest in full as of the date of the Change in Control and convert into Common Units as set forth in the applicable award agreement.

(d) Attorneys' Fees: In the event that Executive substantially prevails in a litigation regarding whether (i) Executive's services were terminated for Cause, or (ii) Executive resigned for Good Reason, Executive shall be entitled to an award including the attorneys' fees and costs Executive incurs in connection with such litigation (including any appeals thereof).

(e) No Mitigation or Offset: Executive shall not be required to mitigate the amount of any payment or other obligation of Company provided for in this Agreement by seeking retention as an independent contractor, employment, or otherwise, and no such payment or other obligation of Company shall be offset or reduced by the amount of any compensation provided to Executive in any subsequent independent contractor or employment relationship.

5. Indemnification: Company agrees to hold harmless and indemnify Executive for any acts or omissions taken or made by Executive during the Term within the scope of his authority as the Chief Financial Officer and Secretary of the Company to the greatest extent allowed by applicable law. Without limiting the foregoing, Executive's right to indemnity hereunder shall include the Company's advancement of all costs and expenses (including attorneys' fees and expenses) in connection with the defense of any actual or threatened claim, subject to Company's receipt of an undertaking by Executive to repay such amount if it shall ultimately be determined that Executive is not entitled to be indemnified by Company as authorized by this Agreement. Additionally, during the Term, and for at least six (6) years following the termination of Executive's appointment as an officer of the Company (regardless of the reason for such termination), Company shall maintain directors and officers insurance for the benefit of Executive that is no less favorable than the directors and officers insurance provided to any other director, officer, or executive of the Company. The rights provided in this Section 5 are in addition to any other rights to indemnification, exculpation, or contribution Executive may otherwise have under any agreement, contract, policy, by-law, certificate of incorporation, or otherwise.

6. Section 409A of the Code:

(a) This Agreement is intended to comply with, or be exempt from, Section 409A of the Code and will be interpreted accordingly. Notwithstanding anything in this Agreement to the contrary, any references under this Agreement to the termination of Executive's appointment as an officer of the Company, or "Termination Date" shall be deemed to refer to the date upon which Executive has experienced a Separation from Service. It is the intent of the Parties that all compensation and benefits payable or provided to Executive (whether under this Agreement or otherwise) shall fully comply with the requirements of Section 409A of the Code. Accordingly, Company agrees that it will not, without Executive's prior written consent, take any action inconsistent with this Agreement that would result in the imposition of tax, interest and/or penalties upon Executive under Section 409A of the Code.

(b) Notwithstanding any provision in this Agreement or elsewhere to the contrary, if upon a termination of employment Executive is deemed to be a "specified employee" within the meaning of Section 409A using the identification methodology selected by Company from time to time, or if none, the default methodology under Section 409A, any payments or benefits due upon a termination of Executive's employment under any arrangement that constitutes a "deferral of compensation" within the meaning of Section 409A shall be delayed and paid or provided (or commence, in the case of installments) on the first payroll date on or following the earlier of (i) the date which is six (6) months and one (1) day after Executive's termination of employment for any reason other than death (the "Delayed Payment Date"), and (ii) the date of Executive's death, and any remaining payments and benefits shall be paid or provided in accordance with the normal payment dates specified for such payment or benefit; provided, that, payments or benefits that qualify as short-term deferral (within the meaning of Section 409A and Final Treasury Regulations Section 1.409A-1(b)(4)) or involuntary separation pay (within the meaning of Section 409A and Final Treasury Regulations Section 1.409A-1(b)(9)(iii)(A)) and are otherwise permissible under Section 409A and the Final Treasury Regulations, shall not be subject to such six-month delay. On the Delayed Payment Date, Company will pay to Executive a lump sum equal to all amounts that would have been paid during the period of the delay if the delay were not required plus interest on such amount at a rate equal to the short-term applicable federal rate then in effect, and will thereafter continue to pay Executive the Severance Payment in installments in accordance with this Section. Additionally, to the extent that Executive's receipt of any in-kind benefits from Company or its Affiliates must be delayed pursuant to this Section 6(b), Executive may elect to instead purchase and receive such benefits during the period in which the provision of benefits would otherwise be delayed by paying Company or its Affiliates, as applicable, for the fair market value of such benefits (as determined by Company in good faith) during such period. Any amounts paid by the Company pursuant to the preceding sentence shall be reimbursed to Executive (with interest thereon) as described above on the date that is six (6) months following Executive's Separation From Service.

(c) Each payment made under this Agreement shall be designated as a "separate payment" within the meaning of Section 409A of the Code.

(d) To the extent that any payment hereunder is subject to Section 409A of the Code and may be payable in one of two calendar years, payment shall be made in the later year.

(e) In the event that either Executive or Company's senior management becomes aware that any provision of this Agreement violates Section 409A of the Code, the Parties will meet and confer regarding such issues and will engage in good faith discussions regarding whether and how the Agreement can be modified so as to minimize the likelihood of a Section 409A violation while providing Executive with financial terms substantially commensurate to those set forth in this Agreement.

(f) Notwithstanding the foregoing, the Company and the Partnership make no representations or warranties and will have no liability to Executive or any other person if any provisions of or payments under this Agreement are determined to constitute deferred compensation subject to Section 409A of the Code but not to satisfy the conditions of Section 409A of the Code.

7. **<u>Tax Withholding</u>**. Company may withhold from any payments or benefits referenced under this Agreement, and payable from the Company to Executive, all federal, state, city or other taxes as shall be required pursuant to any law or governmental regulation or ruling, and any deductions authorized by Executive.

8. **<u>Entire Agreement</u>**: This Agreement constitutes the entire agreement between Executive and Company with respect to the subject matter hereof and supersedes any and all prior agreements, understandings, discussions, negotiations, and/or undertakings, whether written or oral. Executive specifically agrees that Executive is not relying on any representations, promises, understandings, discussions, negotiations, or undertakings, whether written or oral, express or implied, other than those contained in this Agreement. Notwithstanding the foregoing, for the avoidance of doubt, nothing in this Agreement supersedes or affects the validity of any indemnification agreement, long term incentive plan, or equity, severance, bonus or other similar agreement between Executive and Company, or any of its parents, subsidiaries, affiliates, or related companies, or any of their successors, which shall remain in effect in accordance with their terms.

9. **<u>Governing Law</u>**: This Agreement shall be interpreted and enforced in accordance with the laws of the State of Texas, without regard to the principles of conflict of laws.

10. **<u>Invalid or Unenforceable Provisions</u>**: If any provision of this Agreement is determined to be unenforceable as a matter of governing law, a reviewing shall have the authority to "blue pencil" or otherwise modify such provision so as to render it enforceable while maintaining the Parties' original intent (as reflected herein) to the maximum extent possible. This Agreement shall be severable, and the invalidity or unenforceability of any particular provision of this Agreement shall not affect the other provisions hereof.

11. **<u>Successors and Assigns; Third Party Beneficiary</u>**:

(a) This Agreement shall be binding upon and shall inure to the benefit of Company, and its successors and assigns, and Company shall require any successor or assign to expressly assume and agree to perform this Agreement in the same manner and to the same extent that Company would be required to perform this Agreement if no such succession or assignment had taken place. The term "Company" as used herein shall include each such entity's successors and assigns. The term "successors and assigns" as used herein shall include, without limitation, a corporation or other entity acquiring a majority ownership of Company or all or substantially all the assets and business of Company (including this Agreement), whether by operation of law or otherwise.

(b) Neither this Agreement nor any right or interest hereunder shall be assignable or transferable by Executive, or by Executive's beneficiaries or legal representatives, except by will or by the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by Executive's legal personal representative.

12. No Waiver: No failure on the part of any Party at any time to require the performance by any other Party of any term of this Agreement shall be taken or held to be a waiver of such term or in any way affect such Party's right to enforce such term, and no waiver on the part of any Party of any term of this Agreement shall be taken or held to be a waiver of any other term hereof or the breach hereof.

13. Modification or Amendment: This Agreement may not be modified, altered, or amended, nor shall any new contract be entered into between the Parties hereto, except in a writing signed by both Executive and the Board.

14. Headings: Headings and other captions in this Agreement are for convenience of reference only and shall not be used in interpreting, construing, or enforcing any of the provisions of this Agreement.

15. Construction: The Parties have had ample opportunity to review, and have in fact reviewed and understand, this Agreement. Accordingly, the normal rule of construction, to the effect that any ambiguities are to be resolved against the drafting party, shall not be employed in the interpretation of this Agreement. For purposes of this Agreement, the connectives "and," "or," and "and/or" shall be construed either disjunctively or conjunctively as necessary to bring within the scope of a sentence or clause all subject matter that might otherwise be construed to be outside of its scope.

16. Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed an original and both of which together shall constitute one and the same instrument. Facsimile, PDF, and other true and accurate copies of this Agreement shall have the same force and effect as originals hereof.

17. Right to Counsel: Each Party, including Executive, acknowledges that such Party has had the right to seek the advice of independent legal counsel prior to the execution of this Agreement. By executing this Agreement, each Party warrants and represents to each other Party that (i) the executing Party has consulted with an attorney of the executing Party's choice prior to the execution of this Agreement, to the extent such Party chose to do so, and (ii) that the executing Party understands each and every term and provision of this Agreement without explanation by any other Party. Each Party warrants and represents that such Party is under no duress or other coercion to sign this Agreement and that such Party is signing this Agreement of such Party's own free will.

18. **Notices**: All notices and all other communications provided for in this Agreement (including the Notice of Termination) shall be provided in writing and shall be sent via overnight delivery (with proof of delivery retained by the sending Party) to the following addresses:

IF TO COMPANY:

Sanchez Midstream Partners GP LLC
c/o s Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002
Attention: General Counsel

With a copy to:

Hunton Andrews Kurth LLP
600 Travis Street, Suite 4200
Houston, Texas 77002
Attention: Philip M. Haines

IF TO EXECUTIVE:

Charles C. Ward
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

SANCHEZ MIDSTREAM PARTNERS GP LLC

Dated: August 2, 2019

By: /s/ Charles C. Ward
Name: Charles C. Ward
Title: CFO & Secretary

EXECUTIVE

Dated: August 2, 2019

/s/ Charles C. Ward
Charles C. Ward

Signature Page to Executive Services Agreement

EXECUTIVE SERVICES AGREEMENT

THIS EXECUTIVE SERVICES AGREEMENT (this "Agreement") is made and entered into as of August 2, 2019 (the "Effective Date"), by and between Gerald F. Willinger ("Executive") and Sanchez Midstream Partners GP LLC, a Delaware limited liability company ("Company") and the general partner of Sanchez Midstream Partners LP, a Delaware limited partnership ("Partnership," and together with Company, the "Partnership Parties"). Executive and Company are collectively referred to herein as the "Parties," and individually as a "Party."

WHEREAS, Executive is the Chief Executive Officer of the Company and provides services for and on behalf of the Partnership Parties; and

WHEREAS, the Parties wish to memorialize their agreement with respect to the terms and conditions of Executive's continued employment as the Chief Executive Officer of the Company.

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties, intending to be legally bound, mutually agree as follows:

1. **Term**: Executive agrees to continue to provide services for the Partnership Parties and the Company agrees to continue to engage Executive to serve as the Company's Chief Executive Officer, pursuant to the terms and conditions of this Agreement and continuing until Executive's services are terminated by either Executive or the Company, as applicable, in accordance with Section 4 below (the "Term").

2. **Place of Services**: Executive will perform his duties under this Agreement at the Partnership Parties' offices in Houston, Texas.

3. **Compensation**: During the Term of this Agreement, the Company agrees as follows:

(a) Base Salary: Executive's annual base salary is $600,000, subject to applicable withholdings and deductions (the "Base Salary"). Executive's Base Salary may not be decreased during the Term of this Agreement by the Company, but may be increased in the absolute discretion of the Company's Board of Directors (the "Board"), or, if applicable, an authorized committee thereof, in accordance with the rules and procedures governing the Board. To the extent Executive's Base Salary is increased during the Term, such increased rate shall thereafter be considered Executive's "Base Salary" for purposes of this Agreement.

(b) Annual Bonus: In addition to Executive's Base Salary, during the Term Executive shall continue to receive an annual cash bonus for services rendered by Executive to the Partnership Parties equal to an amount between one hundred percent (100%) and one hundred fifty percent (150%) of Executive's Base Salary, as determined by the Board, in its sole discretion, subject to applicable withholdings and deductions (the "Annual Bonus"). Fifty percent (50%) of the Annual Bonus shall be payable to Executive no later than September 30 of the year for which such Annual Bonus relates, and the remainder of the Annual Bonus, including any true-up and changes determined by the Board, in its sole discretion, shall be payable to Executive no later than

March 31 of the year following the year for which such Annual Bonus relates. For the avoidance of doubt, fifty percent (50%) of Executive's Annual Bonus for fiscal 2019 shall be paid no later than September 30, 2019 and the remainder of such Annual Bonus shall be paid no later than March 31, 2020 and shall include any amounts approved as part of the Annual Bonus by the Board. Executive's Annual Bonus shall be determined in a manner and utilizing a qualitative assessment of financial and individual performance achievements consistent with the determination of Executive's Annual Bonus in prior years; provided, that, the Annual Bonus may not be decreased by the Company during the term of this Agreement, but may be increased in the absolute discretion of the Board, or, if applicable, an authorized committee thereof, in accordance with the rules and procedures governing the Board. To the extent Executive's Annual Bonus is increased during the Term, such increased rate shall thereafter be considered Executive's "Annual Bonus" for purposes of this Agreement.

(c) Long-Term Incentive Compensation Awards: Executive shall be eligible to receive awards under the Sanchez Midstream Partners LP Long-Term Incentive Plan or any successor thereto (the "Plan") and to participate in any long-term incentive programs available generally to the Company's executive officers in the future, both as determined in the sole discretion of the Board, or, if applicable, a committee thereof.

(d) Additional Bonus. If, as of the date that an award under the Plan (or other applicable long-term incentive program of the Company) as described in Section 3(c) above would otherwise be granted, (i) either (1) the common units representing limited partner interests in the Partnership ("Common Units") are no longer publicly traded on (A) any exchange registered with the Securities and Exchange Commission (the "SEC") under Section 6(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") (or any successor to such Section), or (B) any other securities exchange (whether or not registered with the SEC under Section 6(a) (or any successor to such Section) of the Exchange Act) that the Company shall designate as a "National Securities Exchange" for purposes of the Partnership Agreement or the Partnership has otherwise been delisted, (2) the Board has made a public announcement that the Partnership will no longer make cash distributions on the Common Units, or (3) the Board has made a formal determination in writing that no cash distributions will be made on the Common Units for the first quarter of the applicable calendar year, and (ii) as a result of the event(s) described in clause (i), the Board (or the applicable committee) in its discretion elects not to grant any award to the Executive under the Plan (or other applicable long-term incentive program) pursuant to paragraph (c) above, then the Executive will be entitled to an additional cash bonus award, in an amount to be determined by the Board in its discretion and which shall be paid to the Executive at the same time the Annual Bonus is paid (each such additional cash bonus award, an "Additional Bonus"). Notwithstanding the foregoing, no bonus shall be paid in substitution for compensation subject to (and not exempt from) Section 409A of the Code, to the extent such payment would result in the imposition of additional tax, interest and/or penalties upon Executive under Section 409A of the Code.

4. Termination

(a) Services Terminable At-Will; Notice of Termination: The Term and Executive's appointment as an officer of the Company may be terminated by Executive or the Company at any time and for any reason; provided, that, any purported termination by Executive or the Company shall be communicated by a written "Notice of Termination" to the other in accordance with Section 18 below. The Notice of Termination shall (i) indicate the specific termination provision of this Agreement relied upon, (ii) to the extent applicable, set forth in reasonable detail the facts and circumstances claimed to provide a basis for the termination of Executive's services, under the provision so indicated, and (iii) specify the effective "Termination Date" of Executive's services to the Partnership Parties (which shall not be earlier than the date the Notice of Termination is sent, and shall not be later than thirty (30) days after the date of the Notice of Termination is sent).

(b) Definitions: For purposes of this Agreement, the following definitions shall apply:

(i) Affiliate: means, with respect to any Person, any other Person that directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise.

(ii) Cause: the Company will have "Cause" to terminate Executive's services under this Agreement for any of the following reasons:

(A) Executive's conviction of, or plea of nolo contendere to, any felony or crime involving moral turpitude in connection with the performance of his duties to the Partnership Parties;

(B) Executive being charged with, or a defendant in, an action brought by the SEC or another federal or state regulator based primarily on Executive's individual alleged acts or omissions during Executive's appointment as an officer of, or while providing services to, the Partnership Parties;

(C) Executive's commission of a willful and material act of fraud or embezzlement of the Company's funds or other assets causing material damage to the Company; or

(D) Executive's willful and material misrepresentations or concealments on any written reports submitted to the Board;

provided, that, any of the events described in Section 4(b)(ii)(C) or Section 4(b)(ii)(D) above shall constitute Cause only if Executive fails to cure such event to the reasonable satisfaction of the Board within thirty (30) calendar days of receiving written notice from the Board of the event which allegedly constitutes Cause; and provided further that a termination shall not be deemed to be for Cause under Section 4(b)(ii)(C) or Section 4(b)(ii)(D) unless and until there shall have been delivered to Executive a copy of a resolution duly adopted by the affirmative vote of a majority of the members of the Board (other than Executive), at a meeting of the Board called and held for such purpose (after reasonable notice is provided to Executive, and Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, Executive is guilty of the conduct described in Section 4(b)(ii)(C) or Section 4(b)(ii)(D), above, and specifying the particulars thereof in detail.

For the purposes of this provision, no act or failure to act on the part of Executive shall be considered "willful" unless it is done, or omitted to be done, by Executive in bad faith and without reasonable belief that Executive's actions or omission was in the best interests of the Partnership Parties. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board, or upon the instructions of the Board, or based upon the advice of counsel for the Company, shall be conclusively presumed to be done, or omitted to be done, by Executive in good faith and in the best interests of the Partnership Parties.

(iii) Change in Control: means the occurrence of any of the following events: (A) the Company withdraws or is removed as the general partner of the Partnership, (B) the Company transfers any portion of its general partner interest in the Partnership to any Person other than an Affiliate of the Company, (C) any merger, consolidation or other transaction involving the Partnership or the Company and another Person (other than an Affiliate thereof), whether in one or a series of related transactions, which results in one or more Persons directly or indirectly acquiring control over more than fifty percent (50%) of the equity interests of the Partnership or the Company, as applicable, (D) the direct or indirect sale, transfer, conveyance or other disposition, in one or a series of related transactions, of all or substantially all of the assets of the Partnership, (E) any dissolution or liquidation of the Partnership or the Company (other than in connection with a bankruptcy proceeding or a statutory winding up); or (F) any other transaction pursuant to which the Company or any Affiliate controlled by the Company exercises its rights to purchase all of the Partnership's common units representing limited partner interests ("Common Units") pursuant to Section 15.1 of the Agreement of Limited Partnership of the Partnership, as amended (the "Partnership Agreement").

(iv) Common Unit Price: means (A) if the consideration to be received in the Change in Control by the holders of Common Units is solely cash, the amount of cash consideration per Common Unit or (B) if the consideration to be received in the Change in Control by holders of Common Units is other than solely cash (1) the average of the closing sale prices per Common Unit (or, if no closing sale price is reported, the average of the closing bid and ask prices or, if more than one in either case, the average of the average closing bid and the average closing ask prices) for the ten (10) consecutive trading days immediately preceding, but not including, the effective date of the Change in Control as reported on the principal U.S. securities exchange on which the Common Units are then traded, or (2) the average of the last quoted bid prices for the Common Units in the over-the-counter market as reported by OTC Market Group Inc. or similar organization for the ten (10) consecutive trading days immediately preceding, but not including, the effective date of the Change in Control, if the Common Units are not then listed for trading on a U.S. securities exchange.

(v) Good Reason: Executive will have "Good Reason" to terminate his appointment as an officer of the Company under this Agreement for any of the following reasons to which Executive does not consent in writing:

(A) the relocation of Executive's primary place of performing services for the Partnership Parties to a location more than fifty (50) miles from Executive's primary place of performing services as set forth in Section 2;

(B) a material diminution in Executive's Base Salary;

(C) a material diminution in the authority, duties or responsibilities of Executive to the Partnership Parties; or

(D) any other action or inaction that constitutes the Company's material breach of any provision of this Agreement;

provided, that, any of the conditions described in Section 4(b)(v)(A) through 4(b)(v)(D) above shall constitute Good Reason only if the Company fails to cure such condition to the reasonable satisfaction of Executive within thirty (30) calendar days of receiving written notice from Executive of the condition which allegedly constitutes Good Reason; and provided further, that, Executive's termination shall constitute a termination by Executive for Good Reason only if the Termination Date occurs not later than ninety (90) calendar days following the initial existence of one or more of the conditions described in Section 4(b)(v)(A) through 4(b)(v)(D) above.

(vi) Disability: For purposes of this Agreement, "Disability" shall mean the earlier of:

(A) a written determination by a physician that Executive has been unable to substantially perform his usual and customary services for the Partnership Parties under this Agreement for a period of at least one hundred twenty (120) consecutive days (or one hundred eighty (180) non-consecutive days) during any twelve (12) month period as a result of Executive's incapacity due to mental or physical illness; or

(B) "disability" as such term is defined in the Company's applicable long-term disability insurance plan as it is in effect at the time Executive becomes Disabled.

(vii) Person: means any individual, corporation, limited liability company, joint venture, trust, unincorporated organization, association, government agency or political subdivision thereof, or other entity.

(c) Compensation Upon Certain Events.

(i) Termination by the Company for Cause or by Executive Without Good Reason: If Executive's appointment as an officer of the Company hereunder is terminated by the Company for Cause or by Executive without Good Reason, then::

(A) Company shall pay to Executive an amount equal to Executive's accrued but unpaid then-current Base Salary through the Termination Date, and

(B) the treatment of each long-term incentive compensation award shall be governed by the terms and conditions of the applicable award agreement for such award and the Plan or similar incentive award program under which such award was granted.

(ii) Termination Upon Executive's Death or Disability: Upon Executive's death or Disability:

(A) Company shall pay to Executive (or his designated beneficiaries), an amount equal to Executive's accrued but unpaid then-current Base Salary through the Termination Date;

(B) to the extent not yet paid to Executive (or his designated beneficiaries), Company shall pay to Executive (or his designated beneficiaries) (1) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (2) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(C) any units which may have been awarded to Executive under the Plan or any other long-term incentive programs available generally to the Company's executive officers in the future, in each case, shall vest in full as of the Termination Date and convert into Common Units as set forth in the applicable award agreement.

(iii) Termination by the Company Without Cause or by Executive for Good Reason: If Executive's appointment as an officer of the Company hereunder is terminated by the Company without Cause, or by Executive for Good Reason, then:

(A) Company shall pay to Executive an amount equal to (1) two hundred percent (200%) of Executive's Base Salary; *plus* (2) two hundred percent (200%) of the largest Annual Bonus (including the amount of any Additional Bonus, if applicable) paid to (or due to be paid to) Executive for the year in which the Termination Date occurred or any year in the three (3)-calendar year period immediately preceding the Termination Date, which shall be paid in a single lump sum within fourteen (14) calendar days of the Termination Date;

(B) if Executive timely elects continuation coverage under COBRA, then the Company shall pay the COBRA premiums for Executive and his eligible dependents directly to the applicable insurer(s) during the COBRA continuation period;

(C) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date, an amount equal to all outstanding amounts owed to Executive for services performed by Executive for or on behalf of the Partnership Parties, including, without limitation, (1) the amount of Executive's accrued but unpaid then current Base Salary through the Termination Date, and (2) to the extent not yet

paid to Executive, (a) the amount of Executive's Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (b) the amount of Executive's Annual Bonus for the current year, based on Executive's Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive's Termination Date; and

(D) any units which may have been awarded to Executive under the Plan or any other long-term incentive programs available generally to the Company's executive officers in the future, in each case, shall vest in full as of the Termination Date and convert into Common Units as set forth in the applicable award agreement.

(iv) Change in Control: If, during the period beginning sixty (60) days prior to and ending two (2) years immediately following a Change in Control, either (A) Company terminates the Executive's employment without Cause, (B) the Executive's death occurs, (C) the Executive becomes Disabled, or (D) the Executive terminates his employment with Company for any reason, in each case constituting a "separation from service" within the meaning of Section 409A of the Internal Revenue Code of 1986 (the "Code") ("Separation from Service"), then:

(A) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date: an amount equal to (1) two hundred percent (200%) of Executive's then-current Base Salary; *plus* (2) two hundred percent (200%) of the largest Annual Bonus (including the amount of any Additional Bonus, if applicable) paid to (or due to be paid to) Executive for the year in which the Termination Date occurred or any year in the three calendar year period immediately preceding the Termination Date;

(B) if Executive timely elects continuation coverage under COBRA, then Company shall pay the COBRA premiums for Executive and his eligible dependents directly to the applicable insurer(s) during the COBRA continuation period;

(C) Company shall pay to Executive, in a single lump sum within fourteen (14) calendar days of the Termination Date, an amount equal to all outstanding amounts owed to Executive for services performed by Executive for or on behalf of the Partnership Parties, including, without limitation, (1) the amount of Executive's accrued but unpaid then current Base Salary through the Termination Date, and (2) to the extent not yet

paid to Executive, (a) the amount of Executive’s Annual Bonus for the last full year during which Executive performed services for the Partnership Parties (including the amount of any Additional Bonus, if applicable), and (b) the amount of Executive’s Annual Bonus for the current year, based on Executive’s Annual Bonus for such last full year (including the amount of any Additional Bonus, if applicable) and pro-rated based on Executive’s Termination Date; and

(D) any units which may have been awarded to Executive under the Plan shall vest in full as of the date of the Change in Control and convert into Common Units as set forth in the applicable award agreement.

(d) Attorneys’ Fees: In the event that Executive substantially prevails in a litigation regarding whether (i) Executive’s services were terminated for Cause, or (ii) Executive resigned for Good Reason, Executive shall be entitled to an award including the attorneys’ fees and costs Executive incurs in connection with such litigation (including any appeals thereof).

(e) No Mitigation or Offset: Executive shall not be required to mitigate the amount of any payment or other obligation of Company provided for in this Agreement by seeking retention as an independent contractor, employment, or otherwise, and no such payment or other obligation of Company shall be offset or reduced by the amount of any compensation provided to Executive in any subsequent independent contractor or employment relationship.

5. Indemnification: Company agrees to hold harmless and indemnify Executive for any acts or omissions taken or made by Executive during the Term within the scope of his authority as the Chief Executive Officer of the Company to the greatest extent allowed by applicable law. Without limiting the foregoing, Executive’s right to indemnity hereunder shall include the Company’s advancement of all costs and expenses (including attorneys’ fees and expenses) in connection with the defense of any actual or threatened claim, subject to Company’s receipt of an undertaking by Executive to repay such amount if it shall ultimately be determined that Executive is not entitled to be indemnified by Company as authorized by this Agreement. Additionally, during the Term, and for at least six (6) years following the termination of Executive’s appointment as an officer of the Company (regardless of the reason for such termination), Company shall maintain directors and officers insurance for the benefit of Executive that is no less favorable than the directors and officers insurance provided to any other director, officer, or executive of the Company. The rights provided in this Section 5 are in addition to any other rights to indemnification, exculpation, or contribution Executive may otherwise have under any agreement, contract, policy, by-law, certificate of incorporation, or otherwise.

6. Section 409A of the Code:

(a) This Agreement is intended to comply with, or be exempt from, Section 409A of the Code and will be interpreted accordingly. Notwithstanding anything in this Agreement to the contrary, any references under this Agreement to the termination of Executive's appointment as an officer of the Company, or "Termination Date" shall be deemed to refer to the date upon which Executive has experienced a Separation from Service. It is the intent of the Parties that all compensation and benefits payable or provided to Executive (whether under this Agreement or otherwise) shall fully comply with the requirements of Section 409A of the Code. Accordingly, Company agrees that it will not, without Executive's prior written consent, take any action inconsistent with this Agreement that would result in the imposition of tax, interest and/or penalties upon Executive under Section 409A of the Code.

(b) Notwithstanding any provision in this Agreement or elsewhere to the contrary, if upon a termination of employment Executive is deemed to be a "specified employee" within the meaning of Section 409A using the identification methodology selected by Company from time to time, or if none, the default methodology under Section 409A, any payments or benefits due upon a termination of Executive's employment under any arrangement that constitutes a "deferral of compensation" within the meaning of Section 409A shall be delayed and paid or provided (or commence, in the case of installments) on the first payroll date on or following the earlier of (i) the date which is six (6) months and one (1) day after Executive's termination of employment for any reason other than death (the "Delayed Payment Date"), and (ii) the date of Executive's death, and any remaining payments and benefits shall be paid or provided in accordance with the normal payment dates specified for such payment or benefit; provided, that, payments or benefits that qualify as short-term deferral (within the meaning of Section 409A and Final Treasury Regulations Section 1.409A-1(b)(4)) or involuntary separation pay (within the meaning of Section 409A and Final Treasury Regulations Section 1.409A-1(b)(9)(iii)(A)) and are otherwise permissible under Section 409A and the Final Treasury Regulations, shall not be subject to such six-month delay. On the Delayed Payment Date, Company will pay to Executive a lump sum equal to all amounts that would have been paid during the period of the delay if the delay were not required plus interest on such amount at a rate equal to the short-term applicable federal rate then in effect, and will thereafter continue to pay Executive the Severance Payment in installments in accordance with this Section. Additionally, to the extent that Executive's receipt of any in-kind benefits from Company or its Affiliates must be delayed pursuant to this Section 6(b), Executive may elect to instead purchase and receive such benefits during the period in which the provision of benefits would otherwise be delayed by paying Company or its Affiliates, as applicable, for the fair market value of such benefits (as determined by Company in good faith) during such period. Any amounts paid by the Company pursuant to the preceding sentence shall be reimbursed to Executive (with interest thereon) as described above on the date that is six (6) months following Executive's Separation From Service.

(c) Each payment made under this Agreement shall be designated as a "separate payment" within the meaning of Section 409A of the Code.

(d) To the extent that any payment hereunder is subject to Section 409A of the Code and may be payable in one of two calendar years, payment shall be made in the later year.

(e) In the event that either Executive or Company's senior management becomes aware that any provision of this Agreement violates Section 409A of the Code, the Parties will meet and confer regarding such issues and will engage in good faith discussions regarding whether and how the Agreement can be modified so as to minimize the likelihood of a Section 409A violation while providing Executive with financial terms substantially commensurate to those set forth in this Agreement.

(f) Notwithstanding the foregoing, the Company and the Partnership make no representations or warranties and will have no liability to Executive or any other person if any provisions of or payments under this Agreement are determined to constitute deferred compensation subject to Section 409A of the Code but not to satisfy the conditions of Section 409A of the Code.

7. **Tax Withholding**. Company may withhold from any payments or benefits referenced under this Agreement, and payable from the Company to Executive, all federal, state, city or other taxes as shall be required pursuant to any law or governmental regulation or ruling, and any deductions authorized by Executive.

8. **Entire Agreement**: This Agreement constitutes the entire agreement between Executive and Company with respect to the subject matter hereof and supersedes any and all prior agreements, understandings, discussions, negotiations, and/or undertakings, whether written or oral. Executive specifically agrees that Executive is not relying on any representations, promises, understandings, discussions, negotiations, or undertakings, whether written or oral, express or implied, other than those contained in this Agreement. Notwithstanding the foregoing, for the avoidance of doubt, nothing in this Agreement supersedes or affects the validity of any indemnification agreement, long term incentive plan, or equity, severance, bonus or other similar agreement between Executive and Company, or any of its parents, subsidiaries, affiliates, or related companies, or any of their successors, which shall remain in effect in accordance with their terms.

9. **Governing Law**: This Agreement shall be interpreted and enforced in accordance with the laws of the State of Texas, without regard to the principles of conflict of laws.

10. **Invalid or Unenforceable Provisions**: If any provision of this Agreement is determined to be unenforceable as a matter of governing law, a reviewing shall have the authority to "blue pencil" or otherwise modify such provision so as to render it enforceable while maintaining the Parties' original intent (as reflected herein) to the maximum extent possible. This Agreement shall be severable, and the invalidity or unenforceability of any particular provision of this Agreement shall not affect the other provisions hereof.

11. **Successors and Assigns; Third Party Beneficiary**:

(a) This Agreement shall be binding upon and shall inure to the benefit of Company, and its successors and assigns, and Company shall require any successor or assign to expressly assume and agree to perform this Agreement in the same manner and to the same extent that Company would be required to perform this Agreement if no such succession or assignment had taken place. The term "Company" as used herein shall include each such entity's successors and assigns. The term "successors and assigns" as used herein shall include, without limitation, a corporation or other entity acquiring a majority ownership of Company or all or substantially all the assets and business of Company (including this Agreement), whether by operation of law or otherwise.

(b) Neither this Agreement nor any right or interest hereunder shall be assignable or transferable by Executive, or by Executive's beneficiaries or legal representatives, except by will or by the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by Executive's legal personal representative.

12. No Waiver: No failure on the part of any Party at any time to require the performance by any other Party of any term of this Agreement shall be taken or held to be a waiver of such term or in any way affect such Party's right to enforce such term, and no waiver on the part of any Party of any term of this Agreement shall be taken or held to be a waiver of any other term hereof or the breach hereof.

13. Modification or Amendment: This Agreement may not be modified, altered, or amended, nor shall any new contract be entered into between the Parties hereto, except in a writing signed by both Executive and the Board.

14. Headings: Headings and other captions in this Agreement are for convenience of reference only and shall not be used in interpreting, construing, or enforcing any of the provisions of this Agreement.

15. Construction: The Parties have had ample opportunity to review, and have in fact reviewed and understand, this Agreement. Accordingly, the normal rule of construction, to the effect that any ambiguities are to be resolved against the drafting party, shall not be employed in the interpretation of this Agreement. For purposes of this Agreement, the connectives "and," "or," and "and/or" shall be construed either disjunctively or conjunctively as necessary to bring within the scope of a sentence or clause all subject matter that might otherwise be construed to be outside of its scope.

16. Counterparts. This Agreement may be executed in counterparts, each of which shall be deemed an original and both of which together shall constitute one and the same instrument. Facsimile, PDF, and other true and accurate copies of this Agreement shall have the same force and effect as originals hereof.

17. Right to Counsel: Each Party, including Executive, acknowledges that such Party has had the right to seek the advice of independent legal counsel prior to the execution of this Agreement. By executing this Agreement, each Party warrants and represents to each other Party that (i) the executing Party has consulted with an attorney of the executing Party's choice prior to the execution of this Agreement, to the extent such Party chose to do so, and (ii) that the executing Party understands each and every term and provision of this Agreement without explanation by any other Party. Each Party warrants and represents that such Party is under no duress or other coercion to sign this Agreement and that such Party is signing this Agreement of such Party's own free will.

18. **Notices**: All notices and all other communications provided for in this Agreement (including the Notice of Termination) shall be provided in writing and shall be sent via overnight delivery (with proof of delivery retained by the sending Party) to the following addresses:

IF TO COMPANY:

Sanchez Midstream Partners GP LLC
c/o s Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002
Attention: General Counsel

With a copy to:

Hunton Andrews Kurth LLP
600 Travis Street, Suite 4200
Houston, Texas 77002
Attention: Philip M. Haines

IF TO EXECUTIVE:

Gerald F. Willinger
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

SANCHEZ MIDSTREAM PARTNERS GP LLC

Dated: August 2, 2019

By: /s/ Gerald Willinger
Name: Gerald Willinger
Title: CEO

Signature Page to Executive Services Agreement

EXECUTIVE

Dated: August 2, 2019

/s/ Gerald F. Willinger

Gerald F. Willinger

Signature Page to Executive Services Agreement

AMENDMENT NO. 1
TO
WARRANT EXERCISABLE FOR JUNIOR SECURITIES

This Amendment No. 1 (this "***Amendment***") to Warrant Exercisable for Junior Securities is entered into effective as of February 24, 2021 by Sanchez Midstream Partners LP, a Delaware limited partnership (the "***Partnership***"), and Stonepeak Catarina Holdings LLC, a Delaware limited liability company (the "***Holder***"). Capitalized terms used but not defined herein have the meanings ascribed to them in the Third Amended and Restated Agreement of Limited Partnership of the Partnership, dated as of August 2, 2019, as amended by the Letter Agreement (as defined below).

RECITALS

WHEREAS, on August 2, 2019, the Partnership issued to the Holder that certain Warrant Exercisable for Junior Securities, dated August 2, 2019 (the "***Original Warrant***");

WHEREAS, the Original Warrant entitles the Holder to receive from the Partnership a number of each class of Junior Securities (including Common Units but excluding Excluded Junior Securities) representing ten percent (10%) of the Junior Securities Deemed Outstanding (as defined in the Original Warrant) of such class as of the Exercise Date (as defined in the Original Warrant);

WHEREAS, Junior Securities Deemed Outstanding includes, among other things, the number of such class of Junior Securities reserved for issuance at such time under the stock option or other equity incentive plans approved by the Board of Directors (the "***Board***") of Sanchez Midstream Partners GP LLC, the sole general partner of the Partnership (the "***General Partner***"), regardless of whether such Junior Securities are actually subject to outstanding Options at such time or whether any outstanding Options are actually exercisable at such time;

WHEREAS, the Partnership's Long-Term Incentive Plan, effective March 6, 2015 (the "***LTIP***"), is such an equity incentive plan approved by the Board;

WHEREAS, on November 16, 2020, the Holder entered into a letter agreement with the Partnership and the General Partner (the "***Letter Agreement***"), pursuant to which the Holder was provided the option to elect to receive the Class C Preferred Quarterly Distribution in Common Units for any Quarter following the Quarter ended September 30, 2020, by providing written notice to the Partnership no later than the last day of the calendar month following the end of such Quarter;

WHEREAS, on January 28, 2021, pursuant to the Letter Agreement, the Holder provided its notice of election to receive 12,445,491 Common Units in lieu of receiving Class C Preferred PIK Units with respect to the Class C Preferred Quarterly Distribution for the Quarter ended December 31, 2020 (the "***Fourth Quarter Units***");

WHEREAS, Section 4(a) of the LTIP, provides that upon the issuance of additional Units from time to time, the maximum number of Units that may be delivered or reserved for delivery with respect to the LTIP shall be automatically increased by a number of Units equal to the lesser of (i) fifteen percent (15%) of such additional Units, or (ii) such lesser number of Units as determined by the Board (such increase, the "***LTIP Increase***");

WHEREAS, the maximum LTIP Increase resulting from the issuance of the Fourth Quarter Units is 1,866,823 Units (the "***Fourth Quarter LTIP Units***");

WHEREAS, the Fourth Quarter LTIP Units are Junior Securities Deemed Outstanding for purposes of the Original Warrant; and

WHEREAS, the Partnership and the Holder desire to amend the Original Warrant to include the Fourth Quarter LTIP Units in the definition of Excluded Junior Securities.

NOW, THEREFORE, in consideration of the covenants, conditions and agreements contained herein, the General Partner does hereby amend the Partnership Agreement as follows:

1. Amendments. The Original Warrant is hereby amended as follows:

a. The definition of "Excluded Junior Securities" in Section 1 of the Original Warrant is hereby amended and restated in its entirety as follows:

"**Excluded Junior Securities**" means (i) any class or series of Junior Security that, with respect to distributions on such Junior Securities of cash or property and distributions upon liquidation of the Partnership (taking into account the intended effects of the allocation of gain and losses as provided in this Agreement), ranks junior to the Class C Preferred Units and senior to the Common Units, the proceeds from the sale of which are used to redeem the Class C Preferred Units, and (ii) 1,866,823 Common Units reserved for issuance under the LTIP on February 25, 2021, so long as such Common Units are so reserved or issued pursuant to the LTIP.

b. Section 1 of the Original Warrant is hereby amended by adding the following definition in the applicable alphabetical order therein:

"**LTIP**" means the Partnership's Long-Term Incentive Plan, effective as of March 6, 2015.

2. Agreement in Effect. Except as amended by this Amendment, the Original Warrant shall remain in full force and effect.

3. Applicable Law. This Amendment shall be construed in accordance with and governed by the laws of the State of Delaware, without regard to principles of conflicts of laws.

4. Severability. Each provision of this Amendment shall be considered severable and if for any reason any provision or provisions herein are determined to be invalid, unenforceable or illegal under any existing or future law, such invalidity, unenforceability or illegality shall not impair the operation of or affect those portions of this Amendment that are valid, enforceable and legal.

5. Electronic Signature. This Amendment may be executed via facsimile or other electronic transmission (including portable document format (*pdf)), and any such executed facsimile or electronic copy shall be treated as an original.

[Signature Pages Follow]

IN WITNESS WHEREOF, this Amendment has been executed as of the effective date written above.

PARTNERSHIP:

SANCHEZ MIDSTREAM PARTNERS LP

By: Sanchez Midstream Partners GP LLC,
its general partner

By: /s/ Charles C. Ward
Name: Charles C. Ward
Title: Chief Financial Officer and Secretary

HOLDER:

STONEPEAK CATARINA HOLDINGS, LLC

By: Stonepeak Texas Midstream Holdco LLC, its managing member

By: Stonepeak Associates LLC,
its managing member

By: Stonepeak GP Holdings LP,
its sole member

By: Stonepeak GP Investors LLC,
its general partner

By: Stonepeak GP Investors Manager LLC,
its managing member

By: /s/ Jack Howell
Name: Jack Howell
Title: Senior Managing Director

By: /s/ Luke Taylor
Name: Luke Taylor
Title: Senior Managing Director

Exhibit 10.35

AWARD LETTER AGREEMENT

This AWARD LETTER AGREEMENT (this "*Award Agreement*") is made and entered into on March 13, 2020 (the "*Effective Date*"), by and between Gerald F. Willinger ("*Executive*") and Sanchez Midstream Partners GP LLC, a Delaware limited liability company ("*Company*") and the general partner of Sanchez Midstream Partners LP, a Delaware limited partnership ("*Partnership*"). Executive and the Company are collectively referred to herein as the "*Parties*," and individually as a "*Party*."

WHEREAS, the Parties entered into that certain Executive Services Agreement, dated as of August 2, 2019 (the "*Executive Agreement*");

WHEREAS, Section 3(c) of the Executive Agreement provides that Executive shall be eligible to receive awards (the "*LTIP Bonus*") under the Partnership's Long-Term Incentive Plan (the "*Plan*") and to participate in any long-term incentive programs available generally to the Company's executive officers, both as determined in the sole discretion of the board of directors of the Company (the "*Board*");

WHEREAS, the Company adopted the Plan to provide officers, such as Executive, a means to develop a sense of ownership and personal involvement in the development and financial success of the Partnership and to encourage officers, such as Executive, to remain with and devote their best efforts to the business of the Partnership and, in doing so, advance the interests of the Partnership and its unitholders;

WHEREAS, during the last twelve months, the price of the Partnership's common units representing limited partner interests ("*Common Units*") as listed on the NYSE American stock exchange has dropped from a high of $3.60 to a low of $0.22 (the "*Common Unit Price Decline*");

WHEREAS, as a result of the Common Unit Price Decline, the dilutive effect of an LTIP Bonus to Executive under the Plan would not advance the interests of the Partnership and its unitholders;

WHEREAS, on the date of the execution of this Award Agreement, the Board in its discretion elected to grant an award to Executive with respect to the performance of the Partnership in fiscal 2019 in an amount equal to $1,300,000 (the "*Executive Award*"); and

WHEREAS, as a result of the Board's determination, the Parties wish to memorialize their agreement with respect to the terms and conditions of the Executive Award.

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties intending to be legally bound, mutually agree as follows:

1. **<u>LTIP Bonus</u>**. The Executive Award shall have a grant date value of $1,300,000; *provided*, that the determination as to the form of the award shall be determined between the Effective Date and March 1, 2021. Such determination shall be in the sole discretion of the Board and shall reflect the type of award which the Board determines best advances the interests of the Partnership and its unitholders. If the Board determines that the Executive Award shall be granted under the Plan, then the Board shall also approve the form of award agreement for Executive at such time.

2. **Governing Law**. This Award Agreement shall be interpreted and enforced with the laws of the State of Texas, without regard to the principles of conflict of laws.

3. **Tax Withholding**. Company may withhold from any payments or benefits referenced under this Award Agreement, and payable from the Company to Executive, all federal, state, city or other taxes as shall be required pursuant to any law or governmental regulation or ruling, and any deductions authorized by Executive.

4. **Entire Agreement**: The Executive Agreement and this Award Agreement constitutes the entire agreement between Executive and Company with respect to the subject matter hereof and supersedes any and all prior agreements, understandings, discussions, negotiations, and/or undertakings, whether written or oral. Executive specifically agrees that Notwithstanding the foregoing, for the avoidance of doubt, nothing in this Award Agreement supersedes or affects the validity of any indemnification agreement, long term incentive plan, or equity, severance, bonus or other similar agreement between Executive and Company, or any of its parents, subsidiaries, affiliates, or related companies, or any of their successors, which shall remain in effect in accordance with their terms.

5. **Successors and Assigns; Third Party Beneficiary**:

(a) This Award Agreement shall be binding upon and shall inure to the benefit of Company, and its successors and assigns, and Company shall require any successor or assign to expressly assume and agree to perform the Executive Agreement and this Award Agreement in the same manner and to the same extent that Company would be required to perform the Executive Agreement and this Award Agreement if no such succession or assignment had taken place. The term "*Company*" as used herein shall include each such entity's successors and assigns. The term "*successors and assigns*" as used herein shall include, without limitation, a corporation or other entity acquiring a majority ownership of Company or all or substantially all the assets and business of Company (including this Award Agreement), whether by operation of law or otherwise.

(b) Neither this Award Agreement nor any right or interest hereunder shall be assignable or transferable by Executive, or by Executive's beneficiaries or legal representatives, except by will or by the laws of descent and distribution. This Award Agreement shall inure to the benefit of and be enforceable by Executive's legal personal representative.

6. **Notices**: All notices and all other communications provided for in this Award Agreement (including the Notice of Termination) shall be provided in writing and shall be sent via overnight delivery (with proof of delivery retained by the sending Party) to the following addresses:

IF TO COMPANY:

Sanchez Midstream Partners GP LLC
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002
Attention: General Counsel

With a copy to:

Hunton Andrews Kurth LLP
600 Travis Street, Suite 4200
Houston, Texas 77002
Attention: Philip M. Haines

IF TO EXECUTIVE:

Gerald F. Willinger
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

7. **Modification or Amendment**: This Award Agreement may not be modified, altered, or amended, nor shall any new contract be entered into between the Parties hereto, except in a writing signed by both Executive and the Company and approved by the Board.

8. **Headings**: Headings and other captions in this Award Agreement are for convenience of reference only and shall not be used in interpreting, construing, or enforcing any of the provisions of this Award Agreement.

9. **Counterparts**. This Award Agreement may be executed in counterparts, each of which shall be deemed an original and both of which together shall constitute one and the same instrument. PDF, and other true and accurate copies of this Award Agreement shall have the same force and effect as originals hereof.

[Signature Page Follows]

SANCHEZ MIDSTREAM PARTNERS GP LLC

Dated: March 13, 2020

By: /s/ Charles C. Ward
Name: Charles C. Ward
Title: Chief Financial Officer & Secretary

EXECUTIVE

Dated: March 13, 2020

/s/ Gerald Willinger
Name: Gerald F. Willinger

Signature Page to Award Letter Agreement (G. Willinger)

AWARD LETTER AGREEMENT

This AWARD LETTER AGREEMENT (this "*Award Agreement*") is made and entered into on March 13, 2020 (the "*Effective Date*"), by and between Charles C. Ward ("*Executive*") and Sanchez Midstream Partners GP LLC, a Delaware limited liability company ("*Company*") and the general partner of Sanchez Midstream Partners LP, a Delaware limited partnership ("*Partnership*"). Executive and the Company are collectively referred to herein as the "*Parties*," and individually as a "*Party*."

WHEREAS, the Parties entered into that certain Executive Services Agreement, dated as of August 2, 2019 (the "*Executive Agreement*");

WHEREAS, Section 3(c) of the Executive Agreement provides that Executive shall be eligible to receive awards (the "*LTIP Bonus*") under the Partnership's Long-Term Incentive Plan (the "*Plan*") and to participate in any long-term incentive programs available generally to the Company's executive officers, both as determined in the sole discretion of the board of directors of the Company (the "*Board*");

WHEREAS, the Company adopted the Plan to provide officers, such as Executive, a means to develop a sense of ownership and personal involvement in the development and financial success of the Partnership and to encourage officers, such as Executive, to remain with and devote their best efforts to the business of the Partnership and, in doing so, advance the interests of the Partnership and its unitholders;

WHEREAS, during the last twelve months, the price of the Partnership's common units representing limited partner interests ("*Common Units*") as listed on the NYSE American stock exchange has dropped from a high of $3.60 to a low of $0.22 (the "*Common Unit Price Decline*");

WHEREAS, as a result of the Common Unit Price Decline, the dilutive effect of an LTIP Bonus to Executive under the Plan would not advance the interests of the Partnership and its unitholders;

WHEREAS, on the date of the execution of this Award Agreement, the Board in its discretion elected to grant an award to Executive with respect to the performance of the Partnership in fiscal 2019 in an amount equal to $550,000 (the "*Executive Award*"); and

WHEREAS, as a result of the Board's determination, the Parties wish to memorialize their agreement with respect to the terms and conditions of the Executive Award.

NOW, THEREFORE, in consideration of the mutual promises contained herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Parties intending to be legally bound, mutually agree as follows:

1. **<u>LTIP Bonus</u>**. The Executive Award shall have a grant date value of $550,000; *provided*, that the determination as to the form of the award shall be determined between the Effective Date and March 1, 2021. Such determination shall be in the sole discretion of the Board and shall reflect the type of award which the Board determines best advances the interests of the Partnership and its unitholders. If the Board determines that the Executive Award shall be granted under the Plan, then the Board shall also approve the form of award agreement for Executive at such time.

2. **<u>Governing Law</u>**. This Award Agreement shall be interpreted and enforced with the laws of the State of Texas, without regard to the principles of conflict of laws.

3. **<u>Tax Withholding</u>**. Company may withhold from any payments or benefits referenced under this Award Agreement, and payable from the Company to Executive, all federal, state, city or other taxes as shall be required pursuant to any law or governmental regulation or ruling, and any deductions authorized by Executive.

4. **<u>Entire Agreement</u>**: The Executive Agreement and this Award Agreement constitutes the entire agreement between Executive and Company with respect to the subject matter hereof and supersedes any and all prior agreements, understandings, discussions, negotiations, and/or undertakings, whether written or oral. Executive specifically agrees that Notwithstanding the foregoing, for the avoidance of doubt, nothing in this Award Agreement supersedes or affects the validity of any indemnification agreement, long term incentive plan, or equity, severance, bonus or other similar agreement between Executive and Company, or any of its parents, subsidiaries, affiliates, or related companies, or any of their successors, which shall remain in effect in accordance with their terms.

5. **<u>Successors and Assigns; Third Party Beneficiary</u>**:

(a) This Award Agreement shall be binding upon and shall inure to the benefit of Company, and its successors and assigns, and Company shall require any successor or assign to expressly assume and agree to perform the Executive Agreement and this Award Agreement in the same manner and to the same extent that Company would be required to perform the Executive Agreement and this Award Agreement if no such succession or assignment had taken place. The term "*Company*" as used herein shall include each such entity's successors and assigns. The term "*successors and assigns*" as used herein shall include, without limitation, a corporation or other entity acquiring a majority ownership of Company or all or substantially all the assets and business of Company (including this Award Agreement), whether by operation of law or otherwise.

(b) Neither this Award Agreement nor any right or interest hereunder shall be assignable or transferable by Executive, or by Executive's beneficiaries or legal representatives, except by will or by the laws of descent and distribution. This Award Agreement shall inure to the benefit of and be enforceable by Executive's legal personal representative.

6. **<u>Notices</u>**: All notices and all other communications provided for in this Award Agreement (including the Notice of Termination) shall be provided in writing and shall be sent via overnight delivery (with proof of delivery retained by the sending Party) to the following addresses:

IF TO COMPANY:

Sanchez Midstream Partners GP LLC
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002
Attention: General Counsel

With a copy to:

Hunton Andrews Kurth LLP
600 Travis Street, Suite 4200
Houston, Texas 77002
Attention: Philip M. Haines

IF TO EXECUTIVE:

Charles C. Ward
c/o Sanchez Midstream Partners LP
1000 Main Street, Suite 3000
Houston, Texas 77002

7. **Modification or Amendment**: This Award Agreement may not be modified, altered, or amended, nor shall any new contract be entered into between the Parties hereto, except in a writing signed by both Executive and the Company and approved by the Board.

8. **Headings**: Headings and other captions in this Award Agreement are for convenience of reference only and shall not be used in interpreting, construing, or enforcing any of the provisions of this Award Agreement.

9. **Counterparts**. This Award Agreement may be executed in counterparts, each of which shall be deemed an original and both of which together shall constitute one and the same instrument. PDF, and other true and accurate copies of this Award Agreement shall have the same force and effect as originals hereof.

[Signature Page Follows]

SANCHEZ MIDSTREAM PARTNERS GP LLC

Dated: March 13, 2020

By: /s/ Gerald Willinger
Name: Gerald Willinger
Title: Chief Executive Officer

EXECUTIVE

Dated: March 13, 2020

/s/ Charles C. Ward
Charles C. Ward

Signature Page to Award Letter Agreement (C. Ward)

Exhibit 21.1

List of Subsidiaries of Evolve Transition Infrastructure LP

Name	Jurisdiction of Organization
SEP Holdings IV, LLC	Delaware
Catarina Midstream, LLC	Delaware
SECO Pipeline, LLC	Delaware
SNMP Services Inc.	Delaware

* The names of certain indirectly owned subsidiaries have been omitted because, considered in the aggregate as a single subsidiary, they would not constitute a significant subsidiary pursuant to Rule 1-02(W) of Regulation S-X.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

To the Partners of Evolve Transition Infrastructure LP and the Board of Directors of Evolve Transition Infrastructure GP LLC
Evolve Transition Infrastructure LP:

We consent to the incorporation by reference in the registration statements (Nos. 333-202578, 333-210783, 333-217007 and 333-230273) on Form S-8, and (Nos. 333-218570 and 333-223569) on Form S-3 of Evolve Transition Infrastructure LP of our report dated March 16, 2021, with respect to the consolidated balance sheets of Evolve Transition Infrastructure LP as of December 31, 2020 and 2019, and the related consolidated statements of operations, changes in partners' capital, and cash flows for each of the years in the two-year period ended December 31, 2020, and the related notes, which report appears in the December 31, 2020 annual report on Form 10-K of Evolve Transition Infrastructure LP.

Our report dated March 16, 2021 contains an explanatory paragraph that states that the Partnership's inability to generate sufficient liquidity to meet future debt obligations raises substantial doubt about its ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of this uncertainty.

/s/ KPMG LLP

Houston, Texas
March 16, 2021

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (713) 651-0849
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294 TELEPHONE (713) 651-9191

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the references to our firm in the Annual Report on Form 10-K for the year ended December 31, 2020 of Evolve Transition Infrastructure LP (the “Form 10-K”) and to the inclusion of our report, dated February 15, 2021, with respect to the estimates of proved reserves, future production and income attributable to certain leasehold interests of Evolve Transition Infrastructure LP as of December 31, 2020, in the Form 10-K and/or as an exhibit to the Form 10-K.

We hereby consent to the incorporation by reference in the Registration Statement on Form S-8 (Nos. 333-202578, 333-210783, 333-217007 and 333-230273), and Form S-3 (Nos. 333-218570 and 333-223569) of Sanchez Midstream Partners LP, including any amendments thereto, of such information.

/s/ Ryder Scott Company, L.P.

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas
March 16, 2021

SUITE 600, 1015 4TH STREET, S.W.	CALGARY, ALBERTA T2R 1J4	TEL (403) 262-2799	FAX (403) 262-2790
621 17TH STREET, SUITE 1550	DENVER, COLORADO 80293-1501	TEL (303) 623-9147	FAX (303) 623-4258

Exhibit 31.1

EVOLVE TRANSITION INFRASTRUCTURE LP
CERTIFICATION

I, Gerald F. Willinger, certify that:

1. I have reviewed this annual report on Form 10-K of Evolve Transition Infrastructure 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 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 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:

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: March 16, 2021

/s/ Gerald F. Willinger
Gerald F. Willinger
Chief Executive Officer
Evolve Transition Infrastructure GP, LLC, as general partner of Evolve Transition Infrastructure LP
(Principal Executive Officer)

Exhibit 31.2

EVOLVE TRANSITION INFRASTRUCTURE LP
CERTIFICATION

I, Charles C. Ward, certify that:

1. I have reviewed this annual report on Form 10-K of Evolve Transition Infrastructure 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 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 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:

   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: March 16, 2021

/s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer and Secretary
Evolve Transition Infrastructure GP, LLC, the general partner of
Evolve Transition Infrastructure LP
(Principal Financial Officer)

**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 accompanying annual report of Evolve Transition Infrastructure LP (the "Partnership") on Form 10-K for the year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Gerald F. Willinger, Chief Executive Officer of Evolve Transition Infrastructure GP LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my 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 Partnership.

Date: March 16, 2021

/s/ Gerald F. Willinger

Gerald F. Willinger
Chief Executive Officer
Evolve Transition Infrastructure GP, LLC, as general partner of
Evolve Transition Infrastructure LP
(Principal Executive Officer)

Exhibit 32.2

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 accompanying annual report of Evolve Transition Infrastructure LP (the "Partnership") on Form 10-K for the year ended December 31, 2020 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Charles C. Ward, Chief Financial Officer and Secretary of Evolve Transition Infrastructure GP LLC, the general partner of the Partnership, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to my 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 Partnership.

Date: March 16, 2021

/s/ Charles C. Ward
Charles C. Ward
Chief Financial Officer and Secretary
Evolve Transition Infrastructure GP, LLC, as general partner of
Evolve Transition Infrastructure LP
(Principal Financial Officer)

SANCHEZ MIDSTREAM PARTNERS LP

Estimated

Future Reserves and Income

Attributable to Certain

Leasehold Interests

SEC Parameters

As of

December 31, 2020

/s/ Eric T. Nelson	/s/ Keith L. Woodrome
Eric T. Nelson, P.E.	Keith L. Woodrome, P.E.
TBPE License No. 102286	TBPE License No. 110424
Managing Senior Vice President	Vice President
[SEAL]	**[SEAL]**

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS
TBPE REGISTERED ENGINEERING FIRM F-1580
1100 LOUISIANA SUITE 4600 HOUSTON, TEXAS 77002-5294
FAX (713) 651-0849
TELEPHONE (713) 651-9191

February 15, 2021

Sanchez Midstream Partners LP
1360 Post Oak Blvd, Suite 2400
Houston, Texas 77056

Ladies and Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved reserves, future production, and income attributable to certain leasehold interests of Sanchez Midstream Partners LP (SNMP) as of December 31, 2020. The subject properties are located in the states of Louisiana and Texas. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on February 12, 2021 and presented herein, was prepared for public disclosure by SNMP in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved liquid hydrocarbon reserves and 100 percent of the total net proved gas reserves of SNMP as of December 31, 2020.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2020 are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary considerably from the prices required by SEC regulations. The recoverable reserves volumes and the income attributable thereto have a direct relationship to the hydrocarbon prices actually received; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized as follows.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Sanchez Midstream Partners LP
As of December 31, 2020

	Proved		
	Developed		Total
	Producing	Non-Producing	Proved
Net Reserves			
Oil/Condensate – Mbbl	1,516	200	1,716
Plant Products – Mbbl	237	42	279
Gas – MMcf	1,466	260	1,726
MBOE	1,997	285	2,282
Income Data ($M)			
Future Gross Revenue	$ 59,571	$ 8,128	$ 67,699
Deductions	44,419	6,542	50,961
Future Net Income (FNI)	$ 15,152	$ 1,586	$ 16,738
Discounted FNI @ 10%	$ 10,860	$ 1,021	$ 11,881

Liquid hydrocarbons are expressed in standard 42 U.S. gallon barrels and shown herein as thousands of barrels (Mbbl). All gas volumes are reported on an "as sold basis" expressed in millions of cubic feet (MMcf) at the official temperature and pressure bases of the areas in which the gas reserves are located. The net reserves are also shown herein on an equivalent unit basis wherein natural gas is converted to oil equivalent using a factor of 6,000 cubic feet of natural gas per one barrel of oil equivalent. MBOE means thousands of barrels of oil equivalent. In this report, the revenues, deductions, and income data are expressed as thousands of U.S. dollars ($M).

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package ARIES™ Petroleum Economics and Reserves Software, a copyrighted program of Halliburton. The program was used at the request of SNMP. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes, workover costs, oil and natural gas gathering, marketing and transportation costs, and certain abandonment costs net of salvage. The "Other" costs shown in the cash flow projections are the variable portion of direct operating costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 95 percent and gas reserves account for the remaining five percent of total future gross revenue from proved reserves.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

Discount Rate Percent	Discounted Future Net Income As of December 31, 2020 Total Proved ($M)
8	$12,664
9	$12,261
12	$11,183
15	$10,274

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "PETROLEUM RESERVES DEFINITIONS" is included as an attachment to this report.

The various reserves status categories are defined in the attachment entitled "PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES" in this report. The proved developed non-producing reserves included herein consist of the shut-in status category.

The proved shut-in reserves included in this report are attributable to wells that are currently awaiting mechanical, pipeline, or field operations that will allow the well to produce at economic rates. These operations may include artificial lift optimization/installation, pipeline remediation, and workovers such as tubing and casing leak repairs and cleanouts.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved gas volumes presented herein do not include volumes of gas consumed in operations as reserves.

Reserves are "estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations." All reserves estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-categorized as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At SNMP's request, this report addresses only the proved reserves attributable to the properties evaluated herein.

Proved oil and gas reserves are "those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward." The proved reserves included herein were estimated using deterministic methods. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a "high degree of confidence that the quantities will be recovered."

Proved reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

SNMP’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing**,** the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved reserves actually recovered and amounts of proved income actually received to differ significantly from the estimated quantities.

The estimates of proved reserves presented herein were based upon a detailed study of the properties in which SNMP owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used individually or in combination by the reserves evaluator in the process of estimating the quantities of reserves. Reserves evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserves quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserves category assigned by the evaluator. Therefore, it is the categorization of reserves quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely to be achieved than not.” The SEC states that “probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered." The SEC states that "possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves." All quantities of reserves within the same reserves category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserves categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserves categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

All of the proved producing and shut-in reserves attributable to producing and shut-in wells and/or reservoirs were estimated by performance methods. These performance methods include, but may not be limited to, decline curve analysis, which utilized extrapolations of historical production and pressure data available through November 2020 in those cases where such data were considered to be definitive. The data utilized in this analysis were furnished to Ryder Scott by SNMP and were considered sufficient for the purpose thereof.

To estimate economically recoverable proved oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

SNMP has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved production and income, we have relied upon data furnished by SNMP with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, workover and recompletion costs, development plans, abandonment costs after salvage, product prices based on the SEC regulations and adjustments or differentials to product prices. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by SNMP. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the "SEC Regulations." In our opinion, the proved reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied until depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Test data and other related information were used to estimate the anticipated initial production rates for those wells that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by SNMP. Wells that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

SNMP furnished us with the above mentioned average prices in effect on December 31, 2020. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic area included in the report.

The product prices which were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were furnished to us by SNMP. The differentials furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the data used by SNMP to determine these differentials.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Realized Prices
North America				
United States	Oil/Condensate	WTI Cushing	$39.57/bbl	$37.70/bbl
	NGLs	Mt. Belvieu - Propane	$18.70/bbl	$10.69/bbl
	Gas	Henry Hub	$1.985/MMBTU	$2.02/Mcf

The term MMBTU denotes millions of British thermal units.

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by SNMP and are based on the operating expense reports of SNMP and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. For operated properties, the operating costs include an appropriate level of corporate general administrative and overhead costs. The operating costs for non-operated properties include the COPAS overhead costs that are allocated directly to the leases and wells under terms of operating agreements. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by SNMP. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by SNMP and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. The development costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of these costs. The estimated net cost of abandonment after salvage was included for properties where abandonment costs net of salvage were material. The estimates of the net abandonment costs furnished by SNMP were accepted without independent verification.

The proved developed non-producing reserves in this report have been incorporated herein in accordance with SNMP's plans to develop these reserves as of December 31, 2020. The implementation of SNMP's development plans as presented to us and incorporated herein is subject to the approval process adopted by SNMP's management. As the result of our inquiries during the course of preparing this report, SNMP has informed us that the development activities included herein have been subjected to and received the internal approvals required by SNMP's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to SNMP. Additionally, SNMP has informed us that they are not aware of any legal, regulatory, or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2020, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by SNMP were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have approximately eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization. Regulating agencies require that, in order to maintain active status, a certain amount of continuing education hours be completed annually, including an hour of ethics training. Ryder Scott fully supports this technical and ethics training with our internal requirement mentioned above.

We are independent petroleum engineers with respect to Sanchez Midstream Partners LP. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Sanchez Midstream Partners LP.

SNMP makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Furthermore, SNMP has certain registration statements filed with the SEC under the 1933 Securities Act into which any subsequently filed Form 10-K is incorporated by reference. We have consented to the incorporation by reference in the registration statements on Form S-3 and Form S-8 of SNMP, of the references to our name, as well as to the references to our third party report for SNMP, which appears in the December 31, 2020 annual report on Form 10-K of SNMP. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by SNMP.

We have transmitted to SNMP a signed digital version of this report letter. In the event there are any differences between the version included in filings made by SNMP and the original transmitted report letter, the original transmitted report letter shall control and supersede the filed version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

/s/ Eric T. Nelson

Eric T. Nelson, P.E.
TBPE License No. 102286
Managing Senior Vice President **[SEAL]**

/s/ Keith L. Woodrome

Keith L. Woodrome, P.E.
TBPE License No. 110424
Vice President **[SEAL]**

ETN-KLW (VRR)/pl

Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. Mr. Eric T. Nelson is the primary technical person responsible for the estimate of the reserves, future production and income.

Mr. Nelson, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2005, is a Managing Senior Vice President and a member of the Board of Directors. He is responsible for ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Nelson served in a number of engineering positions with Exxon Mobil Corporation. For more information regarding Mr. Nelson's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Company/Employees.

Mr. Nelson earned a Bachelor of Science degree in Chemical Engineering from the University of Tulsa in 2002 (summa cum laude) and a Master of Business Administration from the University of Texas in 2007 (Dean's Award). He is a licensed Professional Engineer in the State of Texas. Mr. Nelson is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Texas Board of Professional Engineers requires a minimum of 15 hours of continuing education annually, including at least one hour in the area of professional ethics, which Mr. Nelson fulfills. As part of his 2020 continuing education hours, Mr. Nelson attended over 20 hours of training during 2020 covering such topics as updates concerning the implementation of the latest SEC oil and gas reporting requirements, evaluations of resource play reserves, evaluation of simulation models, procedures and software, and ethics training.

Based on his educational background, professional training and more than 15 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Nelson has attained the professional qualifications as a Reserves Estimator set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of June 2019.

PETROLEUM RESERVES DEFINITIONS

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

PREAMBLE

On January 14, 2009, the United States Securities and Exchange Commission (SEC) published the “Modernization of Oil and Gas Reporting; Final Rule” in the Federal Register of National Archives and Records Administration (NARA). The “Modernization of Oil and Gas Reporting; Final Rule” includes revisions and additions to the definition section in Rule 4-10 of Regulation S-X, revisions and additions to the oil and gas reporting requirements in Regulation S-K, and amends and codifies Industry Guide 2 in Regulation S-K. The “Modernization of Oil and Gas Reporting; Final Rule”, including all references to Regulation S-X and Regulation S-K, shall be referred to herein collectively as the “SEC regulations”. The SEC regulations take effect for all filings made with the United States Securities and Exchange Commission as of December 31, 2009, or after January 1, 2010. Reference should be made to the full text under Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) for the complete definitions (direct passages excerpted in part or wholly from the aforementioned SEC document are denoted in italics herein).

Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. Under the SEC regulations as of December 31, 2009, or after January 1, 2010, a company may optionally disclose estimated quantities of probable or possible oil and gas reserves in documents publicly filed with the SEC. The SEC regulations continue to prohibit disclosure of estimates of oil and gas resources other than reserves and any estimated values of such resources in any document publicly filed with the SEC unless such information is required to be disclosed in the document by foreign or state law as noted in §229.1202 Instruction to Item 1202.

Reserves estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change.

Reserves may be attributed to either natural energy or improved recovery methods. Improved recovery methods include all methods for supplementing natural energy or altering natural forces in the reservoir to increase ultimate recovery. Examples of such methods are pressure maintenance, natural gas cycling, waterflooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids. Other improved recovery methods may be developed in the future as petroleum technology continues to evolve.

Reserves may be attributed to either conventional or unconventional petroleum accumulations. Petroleum accumulations are considered as either conventional or unconventional based on the nature of their in-place characteristics, extraction method applied, or degree of processing prior to sale.

Examples of unconventional petroleum accumulations include coalbed or coalseam methane (CBM/CSM), basin-centered gas, shale gas, gas hydrates, natural bitumen and oil shale deposits. These unconventional accumulations may require specialized extraction technology and/or significant processing prior to sale.

Reserves do not include quantities of petroleum being held in inventory.

Because of the differences in uncertainty, caution should be exercised when aggregating quantities of petroleum from different reserves categories.

RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(26) defines reserves as follows:

Reserves. *Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.*

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

PROVED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(22) defines proved oil and gas reserves as follows:

Proved oil and gas reserves. *Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.*

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

PROVED RESERVES (SEC DEFINITIONS) CONTINUED

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PETROLEUM RESERVES STATUS DEFINITIONS AND GUIDELINES

As Adapted From:
RULE 4-10(a) of REGULATION S-X PART 210
UNITED STATES SECURITIES AND EXCHANGE COMMISSION (SEC)

and

2018 PETROLEUM RESOURCES MANAGEMENT SYSTEM (SPE-PRMS)
Sponsored and Approved by:
SOCIETY OF PETROLEUM ENGINEERS (SPE)
WORLD PETROLEUM COUNCIL (WPC)
AMERICAN ASSOCIATION OF PETROLEUM GEOLOGISTS (AAPG)
SOCIETY OF PETROLEUM EVALUATION ENGINEERS (SPEE)
SOCIETY OF EXPLORATION GEOPHYSICISTS (SEG)
SOCIETY OF PETROPHYSICISTS AND WELL LOG ANALYSTS (SPWLA)
EUROPEAN ASSOCIATION OF GEOSCIENTISTS & ENGINEERS (EAGE)

Reserves status categories define the development and producing status of wells and reservoirs. Reference should be made to Title 17, Code of Federal Regulations, Regulation S-X Part 210, Rule 4-10(a) and the SPE-PRMS as the following reserves status definitions are based on excerpts from the original documents (direct passages excerpted from the aforementioned SEC and SPE-PRMS documents are denoted in italics herein).

DEVELOPED RESERVES (SEC DEFINITIONS)

Securities and Exchange Commission Regulation S-X §210.4-10(a)(6) defines developed oil and gas reserves as follows:

Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Developed Producing (SPE-PRMS Definitions)

While not a requirement for disclosure under the SEC regulations, developed oil and gas reserves may be further sub-classified according to the guidance contained in the SPE-PRMS as Producing or Non-Producing.

Developed Producing Reserves
Developed Producing Reserves are expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate.

Improved recovery reserves are considered producing only after the improved recovery project is in operation.

<u>Developed Non-Producing</u>
Developed Non-Producing Reserves include shut-in and behind-pipe Reserves.

<u>Shut-In</u>
Shut-in Reserves are expected to be recovered from:

(1) completion intervals that are open at the time of the estimate but which have not yet started producing;
(2) wells which were shut-in for market conditions or pipeline connections; or
(3) wells not capable of production for mechanical reasons.

<u>Behind-Pipe</u>
Behind-pipe Reserves are expected to be recovered from zones in existing wells that will require additional completion work or future re-completion before start of production with minor cost to access these reserves.

In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

<u>UNDEVELOPED RESERVES (SEC DEFINITIONS)</u>

Securities and Exchange Commission Regulation S-X §210.4-10(a)(31) defines undeveloped oil and gas reserves as follows:

Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.