UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☑ **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: 001-35081

Kinder Morgan, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**80-0682103**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*

1001 Louisiana Street, Suite 1000, Houston, Texas 77002

(Address of principal executive offices) (zip code)

Registrant's telephone number, including area code: 713-369-9000

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Class P Common Stock	KMI	New York Stock Exchange
1.500% Senior Notes due 2022	KMI 22	New York Stock Exchange
2.250% Senior Notes due 2027	KMI 27 A	New York Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. 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 (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes ☑ No ☐

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

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

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

Indicate by check mark whether the registrant 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 Securities Exchange Act of 1934). Yes ☐ No ☑

Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant, based on closing prices in the daily composite list for transactions on the New York Stock Exchange on June 30, 2020 was approximately $29,459,747,400. As of February 4, 2021, the registrant had 2,264,450,220 Class P shares outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2021, are incorporated into PART III, as specifically set forth in PART III.

KINDER MORGAN, INC. AND SUBSIDIARIES
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KINDER MORGAN, INC. AND SUBSIDIARIES
GLOSSARY

Company Abbreviations

Calnev	=	Calnev Pipe Line LLC
CIG	=	Colorado Interstate Gas Company, L.L.C.
CPGPL	=	Cheyenne Plains Gas Pipeline Company, L.L.C.
EagleHawk	=	EagleHawk Field Services LLC
Elba Express	=	Elba Express Company, L.L.C.
EIG	=	EIG Global Energy Partners
ELC	=	Elba Liquefaction Company, L.L.C.
EPNG	=	El Paso Natural Gas Company, L.L.C.
FEP	=	Fayetteville Express Pipeline LLC
Hiland	=	Hiland Partners, LP
KinderHawk	=	KinderHawk Field Services LLC
KMBT	=	Kinder Morgan Bulk Terminals, Inc.
KMGP	=	Kinder Morgan G.P., Inc.
KMI	=	Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries
KML	=	Kinder Morgan Canada Limited and its majority-owned and/or controlled subsidiaries
KMLP	=	Kinder Morgan Louisiana Pipeline LLC
KMLT	=	Kinder Morgan Liquid Terminals, LLC
KMP	=	Kinder Morgan Energy Partners, L.P. and its majority-owned and/or controlled subsidiaries
KMTP	=	Kinder Morgan Texas Pipeline LLC
MEP	=	Midcontinent Express Pipeline LLC
NGPL	=	Natural Gas Pipeline Company of America LLC and certain affiliates
Ruby	=	Ruby Pipeline Holding Company, L.L.C.
SFPP	=	SFPP, L.P.
SLNG	=	Southern LNG Company, L.L.C.
SNG	=	Southern Natural Gas Company, L.L.C.
TGP	=	Tennessee Gas Pipeline Company, L.L.C.
TMEP	=	Trans Mountain Expansion Project
TMPL	=	Trans Mountain Pipeline System
Trans Mountain	=	Trans Mountain Pipeline ULC
WIC	=	Wyoming Interstate Company, L.L.C.
WYCO	=	WYCO Development L.L.C.

Unless the context otherwise requires, references to "we," "us," "our," or "the Company" are intended to mean Kinder Morgan, Inc. and its majority-owned and/or controlled subsidiaries.

Common Industry and Other Terms

2017 Tax Reform	=	The Tax Cuts & Jobs Act of 2017
/d	=	per day
AFUDC	=	allowance for funds used during construction
BBtu	=	billion British Thermal Units
Bcf	=	billion cubic feet
CERCLA	=	Comprehensive Environmental Response, Compensation and Liability Act
C$	=	Canadian dollars
CO_2	=	carbon dioxide or our CO_2 business segment
COVID-19	=	Coronavirus Disease 2019, a widespread contagious disease, or the related pandemic declared and resulting worldwide economic downturn
CPUC	=	California Public Utilities Commission
DCF	=	distributable cash flow
DD&A	=	depreciation, depletion and amortization
Dth	=	dekatherms
EBDA	=	earnings before depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments
EBITDA	=	earnings before interest, income taxes, depreciation, depletion and amortization expenses, including amortization of excess cost of equity investments
EPA	=	United States Environmental Protection Agency
FASB	=	Financial Accounting Standards Board
FERC	=	Federal Energy Regulatory Commission
GAAP	=	United States Generally Accepted Accounting Principles
IPO	=	Initial Public Offering
LIBOR	=	London Interbank Offered Rate
LLC	=	limited liability company
LNG	=	liquefied natural gas
MBbl	=	thousand barrels
MMBbl	=	million barrels
MMtons	=	million tons
NEB	=	Canadian National Energy Board
NGL	=	natural gas liquids
NYMEX	=	New York Mercantile Exchange
NYSE	=	New York Stock Exchange
OTC	=	over-the-counter
PHMSA	=	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
ROU	=	Right-of-Use
SEC	=	United States Securities and Exchange Commission
U.S.	=	United States of America
WTI	=	West Texas Intermediate

Information Regarding Forward-Looking Statements

This report includes forward-looking statements. These forward-looking statements are identified as any statement that does not relate strictly to historical or current facts. They use words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "outlook," "continue," "estimate," "expect," "may," "will," "shall," or the negative of those terms or other variations of them or comparable terminology. In particular, expressed or implied statements concerning future actions, conditions or events, future operating results or the ability to generate sales, income or cash flow, service debt or pay dividends, are forward-looking statements. Forward-looking statements in this report include, among others, express or implied statements pertaining to: the long-term demand for our assets and services, the future impact on our business of the global economic consequences of the COVID-19 pandemic, including the timing and extent of any economic recovery, and our anticipated dividends and capital projects, including expected completion timing and benefits of those projects.

Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. Future actions, conditions or events and future results may differ materially from those expressed in our forward-looking statements. Many of the factors that will determine these results are beyond our ability to control or accurately predict. Specific factors that could cause actual results to differ from those in our forward-looking statements include:

- changes in supply of and demand for natural gas, NGL, refined petroleum products, oil, CO_2, electricity, petroleum coke, steel and other bulk materials and chemicals and certain agricultural products in North America;
- economic activity, weather, alternative energy sources, conservation and technological advances that may affect price trends and demand;
- competition from other pipelines, terminals or other forms of transportation, or from emerging technologies such as CO_2 capture and sequestration;
- changes in our tariff rates required by the FERC, the CPUC or another regulatory agency;
- the timing and success of our business development efforts, including our ability to renew long-term customer contracts at economically attractive rates;
- our ability to safely operate and maintain our existing assets and to access or construct new assets including pipelines, terminals, gas processing, gas storage and NGL fractionation capacity;
- our ability to attract and retain key management and operations personnel;
- difficulties or delays experienced by railroads, barges, trucks, ships or pipelines in delivering products to or from our terminals or pipelines;
- shut-downs or cutbacks at major refineries, petrochemical or chemical plants, natural gas processing plants, ports, utilities, military bases or other businesses that use our services or provide services or products to us;
- changes in crude oil and natural gas production (and the NGL content of natural gas production) from exploration and production areas that we serve, such as the Permian Basin area of West Texas, the shale plays in North Dakota, Oklahoma, Ohio, Pennsylvania and Texas, and the U.S. Rocky Mountains;
- changes in laws or regulations, third-party relations and approvals, and decisions of courts, regulators and governmental bodies that may increase our compliance costs, restrict our ability to provide or reduce demand for our services, or otherwise adversely affect our business;
- interruptions of operations at our facilities due to natural disasters, damage by third parties, power shortages, strikes, riots, terrorism (including cyber attacks), war or other causes;
- compromise of our IT systems, operational systems or sensitive data as a result of errors, malfunctions, hacking events or coordinated cyber attacks;
- the uncertainty inherent in estimating future oil, natural gas, and CO_2 production or reserves;
- issues, delays or stoppage associated with new construction or expansion projects;

- regulatory, environmental, political, grass roots opposition, legal, operational and geological uncertainties that could affect our ability to complete our expansion projects on time and on budget or at all;

- our ability to acquire new businesses and assets and integrate those operations into our existing operations, and make cost-saving changes in operations, particularly if we undertake multiple acquisitions in a relatively short period of time, as well as our ability to expand our facilities;

- the ability of our customers and other counterparties to perform under their contracts with us including as a result of our customers' financial distress or bankruptcy;

- changes in accounting pronouncements that impact the measurement of our results of operations, the timing of when such measurements are to be made and recorded, and the disclosures surrounding these activities;

- changes in tax laws;

- our ability to access external sources of financing in sufficient amounts and on acceptable terms to the extent needed to fund acquisitions of operating businesses and assets and expansions of our facilities;

- our indebtedness, which could make us vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds, place us at a competitive disadvantage compared to our competitors that have less debt, or have other adverse consequences;

- our ability to obtain insurance coverage without significant levels of self-retention of risk;

- natural disasters, sabotage, terrorism (including cyber attacks) or other similar acts or accidents causing damage to our properties greater than our insurance coverage limits;

- possible changes in our and our subsidiaries' credit ratings;

- conditions in the capital and credit markets, inflation and fluctuations in interest rates;

- political and economic instability of the oil producing nations of the world;

- national, international, regional and local economic, competitive and regulatory conditions and developments, including the effects of any enactment of import or export duties, tariffs or similar measures;

- our ability to achieve cost savings and revenue growth;

- the extent of our success in developing and producing CO_2 and oil and gas reserves, including the risks inherent in development drilling, well completion and other development activities;

- engineering and mechanical or technological difficulties that we may experience with operational equipment, in well completions and work-overs, and in drilling new wells;

- unfavorable results of litigation and the outcome of contingencies referred to in Note 18 "*Litigation and Environmental*" to our consolidated financial statements; and

- the long-term demand for our assets and services and the future impact on our business of the global economic consequences of the COVID-19 pandemic.

The foregoing list should not be construed to be exhaustive. We believe the forward-looking statements in this report are reasonable. However, there is no assurance that any of the actions, events or results expressed in forward-looking statements will occur, or if any of them do, of their timing or what impact they will have on our results of operations or financial condition. Because of these uncertainties, you should not put undue reliance on any forward-looking statements.

The impacts of COVID-19 and decreases in commodity prices resulting from oversupply and demand weakness are discussed in further detail in Note 2 "*Summary of Significant Accounting Policies—COVID-19*" to our consolidated financial statements. Additional discussion of factors that may affect our forward-looking statements, including those associated with

COVID-19, appear elsewhere in this report, including in Item 1A "*Risk Factors,*" Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations,*" and Item 7A "*Quantitative and Qualitative Disclosures About Market Risk—Energy Commodity Market Risk.*" When considering forward-looking statements, you should keep in mind the factors described in this section and the other sections referenced above. We disclaim any obligation, other than as required by applicable law, to publicly update or revise any of our forward-looking statements to reflect future events or developments.

PART I

Items 1 and 2. *Business and Properties.*

We are one of the largest energy infrastructure companies in North America. We own an interest in or operate approximately 83,000 miles of pipelines and 144 terminals. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals store and handle various commodities including gasoline, diesel fuel, chemicals, biodiesel, ethanol, metals and petroleum coke.

General Development of Business

Recent Developments

The following is a listing of significant developments and updates related to our major projects and financing transactions. "Capital Scope" is estimated for our share of the described project which may include portions not yet completed.

Asset or project	Description	Activity	Approx. Capital Scope (KMI Share)
Placed in service			
ELC and SLNG Expansion	Building of new natural gas liquefaction and export facilities at our SLNG natural gas terminal on Elba Island, near Savannah, Georgia, with a total capacity of 2.5 MMtons per year of LNG, equivalent to approximately 357,000 Dth/d of natural gas. Supported by a long-term firm contract with Shell.	SLNG facilities and three of 10 liquefaction units were placed in service in the later part of 2019. The remaining seven units were placed in service during January through August 2020.	$1.2 billion
Permian Highway Pipeline (PHP) Project	Joint venture pipeline project (KMTP 26.67%, BCP PHP, LLC (BCP) 26.67%, Altus Midstream Processing LP 26.67% and an affiliate of an anchor shipper has a 20% ownership interest) is designed to transport up to 2.1 Bcf/d of natural gas through approximately 430 miles of 42-inch pipeline from the Waha, Texas area to the U.S. Gulf Coast and Mexico markets. Subscribed under long-term firm transportation contracts.	Initial commissioning in-service date November 2020. Placed in full commercial service on January 1, 2021.	$652 million
KMI's Crossover II Project	Expansion project that increases the delivery capacity on the Texas intrastate system by 1.4 Bcf/d. This expansion capacity serves LNG, industrial, electric generation and local distribution company expansions along the Texas Gulf Coast.	Placed in service November 2020	$257 million
EPNG South Mainline Expansion	Expansion project that provides 471,000 Dth/d of firm transportation capacity with a first phase of system improvements to deliver volumes to the Sierrita pipeline and the second phase for incremental deliveries of natural gas to Arizona and California. Subscribed under long-term firm transportation contracts.	Phase 1 is already in service. Phase 2 was placed in service July 2020.	$134 million
Other Announcements			
Natural Gas Pipelines			
TGP East 300 Upgrade	Expansion project involves upgrading compression facilities upstream on TGP's system in order to provide 115,000 Dth/d of capacity to Con Edison's distribution system in Westchester County, New York. Supported by a long-term contract with Con Edison.	Expected in-service date is November 2022, pending regulatory approvals.	$246 million
KMLP Acadiana Expansion	Expansion project that will provide 945,000 Dth/d of capacity to serve Train 6 at Cheniere's Sabine pass LNG terminal. Project supported by long-term contracts.	Expected to be placed in service as early as the second quarter 2022, regulatory approvals have been received.	$145 million
NGPL Gulf Coast Southbound Expansion (second phase)	Expansion project to increase southbound capacity on NGPL's Gulf Coast System by approximately 300,000 Dth/d to serve Corpus Christi Liquefaction. Subscribed under a long-term firm transportation contract.	In mid-December 2020, compressor stations 300 and 301 were placed into service. Full project expected in-service date is the first half of 2021.	$101 million

Financings

During 2020, we and our subsidiaries issued approximately $2.25 billion of new senior notes and repaid approximately $2.2 billion of maturing senior notes. We utilized after-tax proceeds from the sale of Pembina stock received from the sale of KML to partially pay down debt that matured in February 2020, and in early January 2021, utilized a portion of proceeds from our August 2020 offerings to repay $750 million of senior notes that were scheduled to mature in March 2021.

Narrative Description of Business

Business Strategy

Our business strategy is to:

- focus on stable, fee-based energy transportation and storage assets that are central to the energy infrastructure and energy transition of growing markets within North America or served by U.S. exports;
- increase utilization of our existing assets while controlling costs, operating safely, and employing environmentally sound operating practices;
- exercise discipline in capital allocation and in evaluating expansion projects and acquisition opportunities;
- leverage economies of scale from expansions of assets and acquisitions that fit within our strategy; and
- maintain a strong financial profile and enhance and return value to our stockholders.

It is our intention to carry out the above business strategy, modified as necessary to reflect changing economic conditions and other circumstances. However, as discussed under Item 1A. *"Risk Factors"* below and at the beginning of this report in "*Information Regarding Forward-Looking Statements*," there are factors that could affect our ability to carry out our strategy or affect its level of success even if carried out.

We regularly consider and enter into discussions regarding potential acquisitions and divestitures, and we are currently contemplating potential transactions. Any such transaction would be subject to negotiation of mutually agreeable terms and conditions, and, as applicable, receipt of fairness opinions, and approval of our board of directors. While there are currently no unannounced purchase or sale agreements for the acquisition or sale of any material business or assets, such transactions can be effected quickly, may occur at any time and may be significant in size relative to our existing assets or operations.

Business Segments

For financial information on our reportable business segments, see Note 16 *"Reportable Segments"* to our consolidated financial statements.

Natural Gas Pipelines

Our Natural Gas Pipelines business segment includes interstate and intrastate pipelines, underground storage facilities and our LNG liquefaction and terminal facilities, and includes both FERC regulated and non-FERC regulated assets.

Our primary businesses in this segment consist of natural gas transportation, storage, sales, gathering, processing and treating, and various LNG services. Within this segment are: (i) approximately 44,000 miles of wholly owned natural gas pipelines and (ii) our equity interests in entities that have approximately 27,000 miles of natural gas pipelines, along with associated storage and supply lines for these transportation networks, which are strategically located throughout the North American natural gas pipeline grid. Our transportation network provides access to the major natural gas supply areas and consumers in the western U.S., Louisiana, Texas, Northeast, Rocky Mountain, Midwest and Southeastern regions. Our LNG terminal facilities also serve natural gas market areas in the southeast. The following tables summarize our significant Natural Gas Pipelines business segment assets, as of December 31, 2020. The design capacity represents transmission, gathering, regasification or liquefaction capacity, depending on the nature of the asset.

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) [(MBbl/d)] Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
East Region				
TGP	11,760	12.14	80	Marcellus, Utica, Gulf Coast, Haynesville, and Eagle Ford shale supply basins; Northeast, Southeast, Gulf Coast and U.S.-Mexico border markets
NGPL (50%)	9,100	7.60	288	Chicago and other Midwest markets and all central U.S. supply basins; north to south deliveries, including deliveries to LNG facilities and to the U.S.-Mexico border markets

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) [(MBbl/d)] Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
KMLP	140	3.00	—	Columbia Gulf, ANR Pipeline Company and various other pipeline interconnects; Cheniere Sabine Pass LNG and industrial markets
SNG (50%)	6,930	4.40	66	Louisiana, Mississippi, Alabama, Florida, Georgia, South Carolina and Tennessee markets; basins in Texas, Oklahoma, Louisiana, Mississippi and Alabama
Florida Gas Transmission (Citrus) (50%)	5,360	3.90	—	Texas to Florida; basins along Louisiana and Texas Gulf Coast, Mobile Bay and offshore Gulf of Mexico
MEP (50%)	515	1.81	—	Oklahoma and north Texas supply with interconnects to Transco, Columbia Gulf, SNG and various other pipelines
Elba Express	190	1.10	—	South Carolina to Georgia; connects to SNG, Transco, SLNG, ELC and Dominion Energy Carolina Gas Transmission
FEP (50%)	185	2.00	—	Arkansas to Mississippi; connects to NGPL, Trunkline Gas Company, Texas Gas Transmission and ANR Pipeline Company
Gulf LNG Holdings (50%)	5	1.50	7	Near Pascagoula, Mississippi; connects to four interstate pipelines and a natural gas processing plant
Bear Creek Storage (75%)	—	—	59	Located in Louisiana; provides storage capacity to SNG and TGP
SLNG	—	1.76	12	Located on Elba Island in Georgia; connects to Elba Express, SNG and Dominion Energy Carolina Gas Transmission
ELC (51%)	—	0.35	—	Located on Elba Island; connects to Elba Express delivering to SLNG for LNG storage and ship loading.
West Region				
EPNG/Mojave	10,685	6.39	44	Permian, San Juan and Anadarko Basins; interconnects and demand locations in California, Arizona, New Mexico, Texas, Oklahoma and Mexico
CIG	4,295	6.00	38	Rocky Mountain and Anadarko Basins; interconnects and demand locations in Colorado, Wyoming, Utah, Montana, Kansas, Oklahoma and Texas
WIC	850	3.61	—	Rocky Mountain Basins; interconnects and demand locations in Colorado, Utah and Wyoming
Ruby (50%)(a)	685	1.53	—	Rocky Mountain Basins; interconnects and demand locations in Utah, Nevada, Oregon and California
CPGPL	415	1.20	—	Rocky Mountain Basins; interconnects and demand locations in Colorado and Kansas
TransColorado	310	0.80	—	San Juan, Permian, Paradox and Piceance Basins; interconnects and demand locations in Colorado and New Mexico
WYCO (50%)	235	1.20	7	Denver Julesburg Basin; interconnects with CIG, WIC, Rockies Express Pipeline, Young Gas Storage and PSCo's pipeline systems
Sierrita (35%)	60	0.52	—	Connects with EPNG near Tucson, Arizona, to the U.S.-Mexico international border crossing near Sasabe, Arizona to supply a third-party natural gas pipeline in Mexico
Young Gas Storage (48%)	15	—	6	Located in Morgan County, Colorado in the Denver Julesburg Basin; capacity is committed to CIG and Colorado Springs Utilities
Keystone Gas Storage	15	—	6	Located in the Permian Basin near the Waha natural gas trading hub in West Texas
Midstream				
KM Texas and Tejas pipelines(b)	5,920	8.30	132 [0.52]	Texas Gulf Coast supply and markets

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Design (Bcf/d) [(MBbl/d)] Capacity	Storage (Bcf) [Processing (Bcf/d)] Capacity	Supply and Market Region
Mier-Monterrey pipeline(b)	90	0.65	—	Starr County, Texas to Monterrey, Mexico; connects to CENEGAS national system and multiple power plants in Monterrey
KM North Texas pipeline(b)	80	0.33	—	Interconnect from NGPL; connects to a 1,750-megawatt Forney, Texas, power plant and a 1,000-megawatt Paris, Texas, power plant
Gulf Coast Express pipeline (34%)	530	2.00	—	Permian Basin to the Agua Dulce, Texas area
PHP (27%)(c)	430	2.10	—	Permian Basin to the Texas Gulf Coast and Mexico markets
Oklahoma				
Oklahoma system	3,580	0.73	[0.09]	Hunton Dewatering, Woodford Shale, Anadarko Basin and Mississippi Lime, Arkoma Basin
Cedar Cove (70%)	115	0.03	—	Oklahoma STACK, capacity excludes third-party offloads
South Texas				
South Texas system	1,160	1.93	[1.02]	Eagle Ford shale, Woodbine and Eaglebine formations
Webb/Duval gas gathering system (91%)	145	0.15	—	South Texas
Camino Real	75	0.15	—	South Texas, Eagle Ford shale formation
EagleHawk (25%)	530	1.20	—	South Texas, Eagle Ford shale formation
KM Altamont	1,515	0.10	[0.1]	Utah, Uinta Basin
Red Cedar (49%)	900	0.33	—	La Plata County, Colorado, Ignacio Blanco Field
Rocky Mountain				
Fort Union (42.595%)	315	1.25	—	Powder River Basin (Wyoming)
Bighorn (51%)	265	0.60	—	Powder River Basin (Wyoming)
KinderHawk	525	2.35	—	Northwest Louisiana, Haynesville and Bossier shale formations
North Texas	545	0.14	—	North Barnett Shale Combo
KM Treating	—	—	—	Odessa, Texas, other locations in Tyler and Victoria, Texas
Hiland - Williston - gas	2,175	0.62	[0.33]	Bakken/Three Forks shale formations - natural gas gathering and processing
Liberty pipeline (50%)	85	[140]	—	Y-grade pipeline from Houston Central complex to the Texas Gulf Coast
South Texas NGL pipelines	340	[115]	—	Ethane and propane pipelines from Houston Central complex to the Texas Gulf Coast
Utopia pipeline (50%)	265	[50]	—	Harrison County, Ohio extending to Windsor, Ontario
Cypress pipeline (50%)	105	[56]	—	Mont Belvieu, Texas to Lake Charles, Louisiana
EagleHawk - Condensate (25%)(d)	400	[220]	—	South Texas, Eagle Ford shale formation

(a) We operate Ruby and own the common interest in Ruby. Pembina owns the remaining interest in Ruby in the form of a convertible preferred interest and has 50% voting rights. If Pembina converted its preferred interest into common interest, we and Pembina would each own a 50% common interest in Ruby.
(b) Collectively referred to as Texas intrastate natural gas pipeline operations.
(c) Initial commissioning during November 2020.
(d) Asset also has storage capacity 60 MBbl.

Competition

The market for natural gas infrastructure is highly competitive, and new pipelines, storage facilities, treating facilities, and facilities for related services are currently being built to serve demand for natural gas in the markets served by the pipelines in our Natural Gas Pipelines business segment. We compete with interstate and intrastate pipelines for connections to new markets and supplies and for transportation, processing, storage and treating services. We believe the principal elements of competition in our various markets are location, rates, terms of service, flexibility, availability of alternative forms of energy and reliability of service. From time to time, projects are proposed that compete with our existing assets. Whether or when any such projects would be built, or the extent of their impact on our operations or profitability is typically not known.

Shippers on our natural gas pipelines compete with other forms of energy available to their natural gas customers and end users, including oil, coal, nuclear and renewables such as hydro, wind and solar power, along with other evolving forms of renewable energy. Several factors influence the demand for natural gas, including price changes, the availability of supply, other forms of energy, the level of business activity, conservation, legislation and governmental regulations, the ability to convert to alternative fuels and weather.

Products Pipelines

Our Products Pipelines business segment consists of our refined petroleum products, crude oil and condensate pipelines, and associated terminals, Southeast terminals, our condensate processing facility and our transmix processing facilities. The following summarizes the significant Products Pipelines business segment assets that we own and operate as of December 31, 2020:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Number of Terminals (a) or locations	Terminal Capacity (MMBbl)	Supply and Market Region
Crude & Condensate				
KM Crude & Condensate pipeline	266	5	2.6	Eagle Ford shale field in South Texas (Dewitt, Karnes, and Gonzales Counties) to the Houston ship channel refining complex
Camino Real Gathering	66	1	0.1	South Texas, Eagle Ford shale formation
Hiland - Williston Basin - oil(b)	1,595	7	0.9	Bakken/Three Forks shale formations - crude oil gathering and transporting
Double H pipeline(b)	512	—	—	Bakken shale in Montana and North Dakota to Guernsey, Wyoming
Double Eagle pipeline (50%)	204	2	0.6	Live Oak County, Texas; Corpus Christi, Texas; Karnes County, Texas; and LaSalle County
KM Condensate Processing Facility (KMCC - Splitter)	—	1	2.0	Houston Ship Channel, Galena Park, Texas
Southeast Refined Products				
PPL pipeline (51%)(c)	3,183	—	—	Louisiana to Washington D.C.
Central Florida pipeline	206	2	2.5	Tampa to Orlando
Southeast Terminals	—	25	8.9	From Mississippi through Virginia, including Tennessee
Transmix Operations	—	5	0.6	Colton, California; Richmond, Virginia; Dorsey Junction, Maryland; St. Louis, Missouri; and Greensboro, North Carolina
West Coast Refined Products				
Pacific (SFPP) (99.5%)	2,845	13	15.2	Six western states
Calnev	566	2	2.0	Colton, California to Las Vegas, Nevada; Mojave region
West Coast Terminals	38	8	9.9	Seattle, Portland, San Francisco and Los Angeles areas

(a) The terminals provide services including short-term product storage, truck loading, vapor handling, additive injection, dye injection and ethanol blending.
(b) Collectively referred to as Bakken Crude assets.
(c) Previously known as Plantation pipeline.

Competition

Our Products Pipelines' pipeline and terminal operations compete against proprietary pipelines and terminals owned and operated by major oil companies, other independent products pipelines and terminals, trucking and marine transportation firms (for short-haul movements of products). Our railcars and our transmix operations compete with refineries owned by major oil companies and independent transmix facilities.

Terminals

Our Terminals business segment includes the operations of our refined petroleum product, chemical, ethanol and other liquid terminal facilities (other than those included in the Products Pipelines business segment) and all of our petroleum coke, metal and ores facilities. Our terminals are located primarily near large U.S. urban centers. We believe the location of our facilities and our ability to provide flexibility to customers help attract new and retain existing customers at our terminals and provide expansion opportunities. We often classify our terminal operations based on the handling of either liquids or dry-bulk material products. In addition, our Terminals' marine operations include Jones Act-qualified product tankers that provide marine transportation of crude oil, condensate and refined petroleum products between U.S. ports. The following summarizes our Terminals business segment assets, as of December 31, 2020:

	Number	Capacity (MMBbl)
Liquids terminals	50	79.7
Bulk terminals	29	—
Jones Act-qualified tankers	16	5.3

Competition

We are one of the largest independent operators of liquids terminals in the U.S., based on barrels of liquids terminaling capacity. Our liquids terminals compete with other publicly or privately held independent liquids terminals, and terminals owned by oil, chemical, pipeline, and refining companies. Our bulk terminals compete with numerous independent terminal operators, terminals owned by producers and distributors of bulk commodities, stevedoring companies and other industrial companies opting not to outsource terminaling services. In some locations, competitors are smaller, independent operators with lower cost structures. Our Jones Act-qualified product tankers compete with other Jones Act-qualified vessel fleets.

CO_2

Our CO_2 business segment produces, transports, and markets CO_2 for use in enhanced oil recovery projects as a flooding medium for recovering crude oil from mature oil fields. Our CO_2 pipelines and related assets allow us to market a complete package of CO_2 supply and transportation services to our customers. We also hold ownership interests in several oil-producing fields and own a crude oil pipeline, all located in the Permian Basin region of West Texas.

Source and Transportation Activities

CO_2 Resource Interests

Our principal market for CO_2 is for injection into mature oil fields in the Permian Basin. Our ownership of CO_2 resources as of December 31, 2020 includes:

	Ownership Interest	Compression Capacity (Bcf/d)	Location
McElmo Dome unit	45 %	1.5	Colorado
Doe Canyon Deep unit	87 %	0.2	Colorado
Bravo Dome unit(a)	11 %	0.3	New Mexico

(a) We do not operate this unit.

CO_2 and Crude Oil Pipelines

The principal market for transportation on our CO_2 pipelines is to customers, including ourselves, using CO_2 for enhanced recovery operations in mature oil fields in the Permian Basin, where industry demand is expected to remain stable in the foreseeable future. The tariffs charged on (i) the Wink crude oil pipeline system are regulated by both the FERC and the Texas Railroad Commission; (ii) the Pecos Carbon Dioxide Pipeline are regulated by the Texas Railroad Commission; and (iii) the Cortez pipeline are based on a consent decree. Our other CO_2 pipelines are not regulated.

Our ownership of CO_2 and crude oil pipelines as of December 31, 2020 includes:

Asset (KMI ownership shown if not 100%)	Miles of Pipeline	Transport Capacity (Bcf/d)	Supply and Market Region
CO_2 pipelines			
Cortez pipeline (53%)	569	1.5	McElmo Dome and Doe Canyon source fields to the Denver City, Texas hub
Central Basin pipeline	337	0.7	Cortez, Bravo, Sheep Mountain, Canyon Reef Carriers, and Pecos pipelines
Bravo pipeline (13%)(a)	218	0.4	Bravo Dome to the Denver City, Texas hub
Canyon Reef Carriers pipeline (98%)	163	0.3	McCamey, Texas, to the SACROC, Sharon Ridge, Cogdell and Reinecke units
Centerline CO_2 pipeline	113	0.3	between Denver City, Texas and Snyder, Texas
Eastern Shelf CO_2 pipeline	98	0.1	between Snyder, Texas and Knox City, Texas
Pecos pipeline (95%)	25	0.1	McCamey, Texas, to Iraan, Texas, delivers to the Yates unit
		(Bbls/d)	
Crude oil pipeline			
Wink pipeline	434	145,000	West Texas to Western Refining's refinery in El Paso, Texas

(a) We do not operate Bravo pipeline.

Oil and Gas Producing Activities

Oil and Gas Producing Interests

Our ownership interests in oil and gas producing fields located in the Permian Basin of West Texas as of December 31, 2020 include the following:

	Working Interest	KMI Gross Developed Acres
SACROC	97 %	49,156
Yates	50 %	9,576
Goldsmith Landreth San Andres	99 %	6,166
Katz Strawn	99 %	7,194
Reinecke	70 %	3,793
Sharon Ridge(a)	14 %	2,619
Tall Cotton	100 %	641
MidCross(a)	13 %	320

(a) We do not operate these fields.

Our oil and gas producing activities are not significant to KMI as a whole; therefore, we do not include the supplemental information on oil and gas producing activities under Accounting Standards Codification Topic 932, Extractive Activities - Oil and Gas.

Gas and Gasoline Plant Interests

Owned and operated gas plants in the Permian Basin of West Texas as of December 31, 2020 include:

	Ownership Interest	Source
Snyder gasoline plant(a)	22 %	The SACROC unit and neighboring CO_2 projects, specifically the Sharon Ridge and Cogdell units
Diamond M gas plant	51 %	Snyder gasoline plant
North Snyder plant	100 %	Snyder gasoline plant

(a) This is a working interest, in addition, we have a 28% net profits interest.

Competition

Our primary competitors for the sale of CO_2 include suppliers that have an ownership interest in McElmo Dome, Bravo Dome and Sheep Mountain CO_2 resources. Our ownership interests in the Central Basin, Cortez and Bravo pipelines are in direct competition with other CO_2 pipelines. We also compete with other interest owners in the McElmo Dome unit and the Bravo Dome unit for transportation of CO_2 to the Denver City, Texas market area.

Major Customers

Our revenue is derived from a wide customer base. For each of the years ended December 31, 2020, 2019 and 2018, no revenues from transactions with a single external customer accounted for 10% or more of our total consolidated revenues. We do not believe that a loss of revenues from any single customer would have a material adverse effect on our business, financial position, results of operations or cash flows.

Industry Regulation

Interstate Natural Gas Transportation and Storage Regulation

As an owner and operator of natural gas companies subject to the Natural Gas Act of 1938, we are required to provide service to shippers on our interstate natural gas pipelines and storage facilities at regulated rates that have been determined by the FERC to be just and reasonable. Recourse rates and general terms and conditions for service are set forth in posted tariffs approved by the FERC for each pipeline (including storage facilities or companies as used herein). Generally, recourse rates are based on our cost of service, including recovery of, and a return on, our investment. Posted tariff rates are deemed just and reasonable and cannot be changed without FERC authorization following an evidentiary hearing or settlement. The FERC can initiate proceedings, on its own initiative or in response to a shipper complaint, that could result in a rate change or confirm existing rates.

Posted tariff rates set the general range of maximum and minimum rates we charge shippers on our interstate natural gas pipelines. Within that range, each pipeline is permitted to charge discounted rates, so long as such discounts are offered to all similarly situated shippers and granted without undue discrimination. Apart from discounted rates, upon mutual agreement, the pipeline is permitted to charge negotiated rates that are not bound by and are irrespective of changes that may occur to the range of tariff-based maximum and minimum rate levels. Negotiated rates provide certainty to the pipeline and the shipper of agreed-upon rates during the term of the transportation agreement, regardless of changes to the posted tariff rates. The actual negotiated rate agreement or a summary of such agreement must be posted as part of the pipelines' tariffs. While pipelines and their shippers may agree to a variety of negotiated rate structures depending on the shipper and circumstance, pipelines generally must use for all shippers the form of service agreement that is contained within their FERC-approved tariff. Any deviation from the *pro forma* service agreements must be filed with the FERC and only certain types of deviations in the terms and conditions of service are acceptable to the FERC.

The FERC regulates the rates, terms and conditions of service, construction and abandonment of facilities by companies performing interstate natural gas transportation services, including storage services, under the Natural Gas Act of 1938. To a lesser extent, the FERC regulates interstate transportation rates, terms and conditions of service under the Natural Gas Policy Act of 1978. Beginning in the mid-1980s, the FERC adopted a number of regulatory changes to ensure that interstate natural gas pipelines operated on a not unduly discriminatory basis and to create a more competitive and transparent environment in the natural gas marketplace. Examples include FERC regulations requiring interstate natural gas pipelines to separate their traditional merchant sales services from their transportation and storage services and provide comparable transportation and storage services with respect to all natural gas customers. Also, natural gas pipelines must separately state the applicable rates for each unbundled service they provide (i.e., for transportation services and storage services for natural gas). To ensure a competitive transportation market, these pipelines must adhere to certain scheduling procedures, accept capacity segmentation in certain circumstances and abide by FERC-established standards of conduct when communicating with marketing affiliates.

In addition to regulatory changes initiated by the FERC, the U.S. Congress passed the Energy Policy Act of 2005. Among other things, the Energy Policy Act amended the Natural Gas Act to: (i) prohibit market manipulation by any entity; (ii) direct the FERC to facilitate market transparency in the market for sale or transportation of physical natural gas in interstate commerce; and (iii) significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder.

Interstate Common Carrier Refined Petroleum Products and Oil Pipeline Rate Regulation

Some of our U.S. refined petroleum products and crude oil gathering and transmission pipelines are interstate common carrier pipelines, subject to regulation by the FERC under the Interstate Commerce Act, or ICA. The ICA requires that we maintain our tariffs on file with the FERC. Those tariffs set forth the rates we charge for providing gathering or transportation services on our interstate common liquids carrier pipelines as well as the rules and regulations governing these services. The ICA requires, among other things, that such rates on interstate common liquids carrier pipelines be "just and reasonable" and nondiscriminatory. The ICA permits interested persons to challenge newly proposed or changed rates and authorizes the FERC to suspend the effectiveness of such rates for a period of up to seven months and to investigate such rates. If, upon completion of an investigation, the FERC finds that the new or changed rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation. The FERC also may investigate, upon complaint or on its own motion, rates that are already in effect and may order a carrier to change its rates prospectively. Upon an appropriate showing, a shipper may obtain reparations for damages sustained during the two years prior to the filing of a complaint.

The Energy Policy Act of 1992 deemed petroleum products pipeline tariff rates that were in effect for the 365-day period ending on the date of enactment or that were in effect on the 365th day preceding enactment and had not been subject to complaint, protest or investigation during the 365-day period to be just and reasonable or "grandfathered" under the ICA. The Energy Policy Act also limited the circumstances under which a complaint can be made against such grandfathered rates. Certain rates on our SFPP operations' pipeline system were subject to protest during the 365-day period established by the Energy Policy Act. Accordingly, certain of the SFPP pipelines' rates have been, and continue to be, the subject of complaints with the FERC, as is more fully described in Note 18 "*Litigation and Environmental*" to our consolidated financial statements.

Petroleum products and crude oil pipelines may change their rates within prescribed ceiling levels that are tied to an inflation index. Shippers may protest rate increases made within the ceiling levels, but such protests must show that the portion of the rate increase resulting from application of the index is substantially in excess of the pipeline's increase in costs from the previous year. A petroleum products or crude oil pipeline must, as a general rule, utilize the indexing methodology to change its rates. Cost-of-service ratemaking, market-based rates and settlement rates are alternatives to the indexing approach and may be used in certain specified circumstances to change rates.

CPUC Rate Regulation

The intrastate common carrier operations of our West Coast Refined Products operations' pipelines in California are subject to regulation by the CPUC under a "depreciated book plant" methodology, which is based on an original cost measure of investment. Intrastate tariffs filed by us with the CPUC have been established on the basis of revenues, expenses and investments allocated as applicable to the California intrastate portion of the West Coast Refined Products operations' business. Tariff rates with respect to intrastate pipeline service in California are subject to challenge by complaint by interested parties or by independent action of the CPUC. A variety of factors can affect the rates of return permitted by the CPUC, and certain other issues similar to those which have arisen with respect to our FERC regulated rates also could arise with respect to its intrastate rates. The intrastate rates for movements in California on our SFPP and Calnev systems have been, and may in the future be, subject to complaints before the CPUC.

Railroad Commission of Texas (RCT) Rate Regulation

The intrastate operations of our crude oil and liquids pipelines and natural gas pipelines and storage facilities in Texas are subject to regulation with respect to such intrastate transportation by the RCT. The RCT has the authority to regulate our rates, though it generally has not investigated the rates or practices of our intrastate pipelines in the absence of shipper complaints.

Mexico - Energy Regulatory Commission

The Mier-Monterrey Pipeline has a natural gas transportation permit granted by the Energy Regulatory Commission of Mexico (the Commission) that defines the conditions for the pipeline to carry out activity and provide natural gas transportation service. This permit expires in 2026.

This permit establishes certain restrictive conditions, including without limitation: (i) compliance with the general conditions for the provision of natural gas transportation service; (ii) compliance with certain safety measures, contingency plans, maintenance plans and the official standards of Mexico regarding safety; (iii) compliance with the technical and economic specifications of the natural gas transportation system authorized by the Commission; (iv) compliance with certain technical studies established by the Commission; and (v) compliance with a minimum contributed capital not entitled to withdrawal of at least the equivalent of 10% of the investment proposed in the project.

Mexico - National Agency for Industrial Safety and Environmental Protection (ASEA)

ASEA regulates environmental compliance and industrial and operational safety. The Mier-Monterrey Pipeline must satisfy and maintain ASEA's requirements, including compliance with certain safety measures, contingency plans, maintenance plans and the official standards of Mexico regarding safety, including a Safety Administration Program.

Safety Regulation

We are also subject to safety regulations issued by PHMSA, including those requiring us to develop and maintain pipeline integrity management programs to evaluate areas along our pipelines and take additional measures to protect pipeline segments located in what are referred to as High Consequence Areas, or HCAs, and Moderate Consequence Areas, or MCAs, where a leak or rupture could potentially do the most harm.

During September 2019, PHMSA finalized rules to be effective July 1, 2020 to expand integrity management program requirements to hazardous liquids pipelines outside of HCAs (with some exceptions) and to make certain other changes to those program requirements, including data integration and emphasis on the use of in-line inspection technology. During October 2019, PHMSA finalized rules to require operators of natural gas pipelines to (i) expand integrity management program requirements outside of HCAs (with some exceptions), and (ii) reconfirm maximum allowable operating pressure (MAOP) on certain pipelines in populated areas including HCAs. The MAOP reconfirmations must be completed by 2035. Changes in technology such as advances of in-line inspection tools, identification of additional integrity threats and changes to PHMSA regulations can have a significant impact on costs to perform integrity assessments, testing and repairs. We will continue our pipeline integrity management programs to assess and maintain the integrity of our existing and future pipelines as required by PHMSA regulations. The costs to comply with integrity management program requirements are difficult to predict. Assessments performed as part of our program could result in significant capital and operating expenditures for upgrades and/or repairs deemed necessary to continue the safe and reliable operation of our pipelines. We expect to increase expenditures in the future to comply with these PHMSA regulations.

The Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016 or "PIPES Act of 2016" requires PHMSA, among other regulators, to set minimum safety standards for underground natural gas storage facilities and allows states to set more stringent standards for intrastate pipelines. In compliance with the PIPES Act of 2016, we have implemented procedures for underground natural gas storage facilities.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which was signed into law in 2012, increased penalties for violations of safety laws and rules and may result in the imposition of more stringent regulations in the future. Regulations, changes to regulations or an increase in public expectations for pipeline safety may require additional reporting, the replacement of some of our pipeline segments, addition of monitoring equipment and more frequent inspection or testing of our pipeline facilities. Repair, remediation, and preventative or mitigating actions may require significant capital and operating expenditures.

From time to time, our pipelines or facilities may experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

We are also subject to the requirements of the Occupational Safety and Health Administration (OSHA) and other federal and state agencies that address employee health, including from infectious diseases such as COVID-19, and safety. In general, we believe we are fulfilling the OSHA requirements and protecting the health and safety of our employees. Based on new or revised regulatory developments, we may be required to increase expenditures in the future to comply with higher industry and regulatory safety standards. However, there are no known new or revised regulations which will require a material increase in our expenditures.

State and Local Regulation

Certain of our activities are subject to various state and local laws and regulations, as well as orders of regulatory bodies, governing a wide variety of matters, including marketing, production, pricing, pollution, protection of the environment, and human health and safety.

Marine Operations

The operation of tankers and marine equipment create maritime obligations involving property, personnel and cargo under General Maritime Law. These obligations create a variety of risks including, among other things, the risk of collision, which may result in claims for personal injury, cargo, contract, pollution, third-party claims and property damages to vessels and facilities.

We are subject to the Jones Act and other federal laws that restrict maritime transportation (between U.S. departure and destination points) to vessels built and registered in the U.S. and owned and crewed by U.S. citizens. As a result, we monitor the foreign ownership of our common stock and under certain circumstances consistent with our certificate of incorporation, we have the right to redeem shares of our common stock owned by non-U.S. citizens. If we do not comply with such requirements, we would be prohibited from operating our vessels in U.S. coastwise trade, and under certain circumstances we would be deemed to have undertaken an unapproved foreign transfer, resulting in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of the vessels. Furthermore, from time to time, legislation has been introduced unsuccessfully in the U.S. Congress to amend the Jones Act to ease or remove the requirement that vessels operating between U.S. ports be built and registered in the U.S. and owned and crewed by U.S. citizens. If the Jones Act were amended in such fashion, we could face competition from foreign-flagged vessels.

In addition, the U.S. Coast Guard and the American Bureau of Shipping maintain the most stringent regime of vessel inspection in the world, which tends to result in higher regulatory compliance costs for U.S.-flag operators than for owners of vessels registered under foreign flags of convenience. The Jones Act and General Maritime Law also provide damage remedies for crew members injured in the service of the vessel arising from employer negligence or vessel unseaworthiness.

The Merchant Marine Act of 1936 is a federal law that provides the U.S. Secretary of Transportation, upon proclamation by the U.S. President of a national emergency or a threat to the national security, the authority to requisition or purchase any vessel or other watercraft owned by U.S. citizens (including us, provided that we are considered a U.S. citizen for this purpose). If one of our vessels were purchased or requisitioned by the U.S. government under this law, we would be entitled to be paid the fair market value of the vessel in the case of a purchase or, in the case of a requisition, the fair market value of charter hire. However, we would not be entitled to compensation for any consequential damages suffered as a result of such purchase or requisition.

Canadian Regulation

The Utopia Pipeline System, owned by a joint venture that we operate and in which we own a 50% interest, originates in Ohio and terminates in Windsor, Ontario, Canada and is therefore subject to U.S. regulation as described in this section and below under the heading "—*Environmental Matters*," as well as similar regulations promulgated by Canadian authorities with respect to natural gas liquids pipelines.

Derivatives Regulation

We use energy commodity derivative contracts as part of our strategy to hedge our exposure to energy commodity market risk and other external risks in the ordinary course of business. The derivative contracts that we use include exchange-traded and OTC commodity financial instruments such as, futures and options contracts, fixed price swaps and basis swaps. The Dodd-Frank Act requires the U.S. Commodity Futures Trading Commission (CFTC) and the SEC to promulgate rules and regulations establishing federal oversight and regulation of the OTC derivatives market and entities that participate in that market. In October 2020, the CFTC finalized one of the last remaining new rules pursuant to the Dodd-Frank Act that institutes broad new aggregate position limits for OTC swaps and futures and options traded on regulated exchanges. As finalized, these rules include exemptions for hedging positions, and while we cannot yet predict the full impact of the rules when they take effect in 2022 and 2023, we do not expect that the rules will have a material adverse effect on our business. We cannot predict how new leadership at the CFTC as a result of the change in the U.S. presidential administration may impact us.

Environmental Matters

Our business operations are subject to federal, state and local laws and regulations relating to environmental protection and human health and safety. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, storage or other facilities, we may experience significant operational disruptions, and we may have to pay a significant amount to clean up the leak, release or spill, pay for government penalties, address natural resource damages, compensate for human exposure or property damage, install costly pollution control equipment or a combination of these and other measures. Furthermore, new projects may require approvals and environmental analysis under federal and state laws, including the Clean Water Act, the National Environmental Policy Act and the Endangered Species Act. The resulting costs and liabilities could materially and negatively affect our business, financial condition, results of operations and cash flows. In addition, emission controls required under federal and state environmental laws for both new and existing facilities could require significant capital expenditures at our facilities. In general, the cost of environmental control at facilities is increasing and limiting the return on capital projects and the number of capital projects that are viable.

Environmental and human health and safety laws and regulations are subject to change. The long term trend in environmental regulation is to place more restrictions and limitations on activities that may be perceived to affect the environment, wildlife, natural resources and human health. There can be no assurance as to the amount or timing of future expenditures for environmental regulation compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and cash flows.

In accordance with GAAP, we record liabilities for environmental matters when it is probable that obligations have been incurred and the amounts can be reasonably estimated. This policy applies to assets or businesses currently owned or previously disposed. We have accrued liabilities for estimable and probable environmental remediation obligations at various sites, including multi-party sites where the EPA or a similar state agency has identified us as one of the potentially responsible parties. The involvement of other financially responsible companies at these multi-party sites could increase or mitigate our actual joint and several liability exposures.

We believe that the ultimate resolution of these environmental matters will not have a material adverse effect on our business, financial position, results of operations or cash flows. However, it is possible that our ultimate liability with respect to these environmental matters could exceed the amounts accrued in an amount that could be material to our business, financial position, results of operations or cash flows in any particular reporting period. We have accrued an environmental reserve in the amount of $250 million as of December 31, 2020. For additional information related to environmental matters, see Note 18 "*Litigation and Environmental*" to our consolidated financial statements.

Hazardous and Non-Hazardous Waste

We generate both hazardous and non-hazardous wastes that are subject to the requirements of the Federal Resource Conservation and Recovery Act and comparable state statutes. From time to time, the EPA, as well as other U.S. federal and state regulators, consider the adoption of stricter disposal standards for non-hazardous waste. Furthermore, it is possible that some wastes that are currently classified as non-hazardous, which could include wastes currently generated during our pipeline or liquids or bulk terminal operations or wastes from oil and gas facilities that are currently exempt as exploration and production waste, may in the future be designated as hazardous wastes. Hazardous wastes are subject to more rigorous and costly handling and disposal requirements than non-hazardous wastes. Such changes in the regulations may result in additional capital expenditures or operating expenses for us.

Superfund

The CERCLA or the Superfund law, and analogous state laws, impose joint and several liability, without regard to fault or the legality of the original conduct, on certain classes of potentially responsible persons for releases of hazardous substances into the environment. These persons include the owner or operator of a site and companies that disposed or arranged for the disposal of the hazardous substances found at the site. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to public health or the environment and to seek to recover from the responsible classes of persons the costs they incur, in addition to compensation for natural resource damages, if any. Although petroleum is excluded from CERCLA's definition of a hazardous substance, in the course of our ordinary operations, we have and will generate materials that may fall within the definition of "hazardous substance." By operation of law, if we are determined to be a potentially responsible person, we may be responsible under CERCLA for all or part of the costs required to clean up sites at which such materials are present, in addition to compensation for natural resource damages, if any.

Clean Air Act

Our operations are subject to the Clean Air Act, its implementing regulations, and analogous state statutes and regulations. The EPA regulations under the Clean Air Act contain requirements for the monitoring, reporting, and control of greenhouse gas (GHG) emissions from stationary sources. For further information, see *"—Climate Change"* below.

Clean Water Act

Our operations can result in the discharge of pollutants. The Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws impose restrictions and controls regarding the discharge of fills and pollutants into waters of the U.S. The discharge of fills and pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by applicable federal or state authorities. The Oil Pollution Act was enacted in 1990 and amends provisions of the Clean Water Act pertaining to prevention of and response to oil spills. Spill prevention, control and countermeasure requirements of the Clean Water Act and some state laws require containment and similar structures to help prevent contamination of navigable waters in the event of an overflow or release of oil.

EPA Revisions to Ozone National Ambient Air Quality Standard (NAAQS)

As required by the Clean Air Act, the EPA establishes National Ambient Air Quality Standards (NAAQS) for how much pollution is permissible, and the states then have to adopt rules so their air quality meets the NAAQS. In October 2015, the EPA published a rule lowering the ground level ozone NAAQS from 75 ppb to a more stringent 70 ppb standard. This change triggered a process under which the EPA designated the areas of the country in or out of compliance with the new NAAQS standard. Now, certain states will have to adopt more stringent air quality regulations to meet the new NAAQS standard. These new state rules, which are expected in 2020 or 2021, will likely require the installation of more stringent air pollution controls on newly-installed equipment and possibly require the retrofitting of existing KMI facilities with air pollution controls. Given the nationwide implications of the new rule, it is expected that it will have financial impacts for each of our business units.

Climate Change

Due to concern over climate change, numerous proposals to monitor and limit emissions of GHGs have been made and are likely to continue to be made at the federal, state and local levels of government. Methane, a primary component of natural gas, and CO_2, which is naturally occurring and also a byproduct of the burning of natural gas, are examples of GHGs. Various laws and regulations exist or are under development to regulate the emission of such GHGs, including the EPA programs to report GHG emissions and state actions to develop statewide or regional programs. The U.S. Congress has in the past considered legislation to reduce emissions of GHGs. Climate-related laws and regulation could lead to reduced demand for hydrocarbon products that are deemed to contribute to GHGs, which in turn could adversely affect demand for our products and services.

Beginning in December 2009, EPA published several findings and rulemakings under the Clean Air Act requiring the permitting and reporting of certain GHGs, including CO_2 and methane. Our facilities are subject to these requirements. Operational and/or regulatory changes could require additional facilities to comply with requirements for reducing, reporting and permitting GHG emissions.

On October 23, 2015, the EPA published as a final rule the Clean Power Plan, which sets interim and final CO_2 emission performance rates for power generating units that are fueled by coal, oil or natural gas. The rule has been the focus of legislative discussion in the U.S. Congress and litigation in federal court. On February 10, 2016, the U.S. Supreme Court stayed the final rule, effectively suspending the duty to comply with the rule until certain legal challenges are resolved. In October 2017, the EPA proposed to repeal the Clean Power Plan. In June 2019, the EPA replaced the Clean Power Plan with the Affordable Clean Energy rule. In January 2021, the U.S. Court of Appeals for the District of Columbia Circuit vacated the Affordable Clean Energy rule and remanded the question to the EPA to consider a new regulatory framework to replace the Affordable Clean Energy rule thereby allowing the incoming administration to implement standards for emissions from the power sector. While we do not operate power plants, it remains unclear what effect new standards might have on the anticipated demand for natural gas, including natural gas that we gather, process, store and transport.

At the state level, more than one-third of the states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional GHG "cap and trade" programs. Although many of the state-level initiatives have to date been focused on large sources of GHG emissions, such as electric power plants, it is possible that sources such as our gas-fueled compressors and processing plants could become subject to related state regulations. Various states are also proposing or have implemented stricter regulations for GHGs that go beyond the requirements of the EPA. Some of the states have implemented regulations that require additional reductions monitoring and reporting of methane emissions. Depending on the state programs pending implementation, we could be required to further reduce emissions, conduct additional monitoring, do additional emissions reporting, install additional emission controls and/or purchase and surrender emission allowances.

Because our operations, including the compressor stations and processing plants, emit various types of GHGs, primarily methane and CO_2, such new legislation or regulation could increase the costs related to operating and maintaining the facilities. Depending on the particular law, regulation or program, we or our subsidiaries could be required to incur capital expenditures for installing new monitoring equipment or emission controls on the facilities, acquire and surrender allowances for the GHG emissions, pay taxes related to the GHG emissions and administer and manage a more comprehensive GHG emissions program. We are not able at this time to estimate such increased costs; however, as is the case with similarly situated companies in our industry, they could be significant to us. While we may be able to include some or all of such increased costs in the rates charged by our or our subsidiaries' pipelines, recovery of costs is uncertain in all cases and may depend on events beyond their control, including the outcome of future rate proceedings before the FERC or other regulatory bodies, and the provisions of any final legislation or other regulations. Any of the foregoing could have an adverse effect on our business, financial position, results of operations and prospects.

Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of hurricanes and tropical storms, and increased frequency of extreme precipitation and flooding. We may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could damage our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. However, the timing, severity and location of these climate change impacts are not known with certainty and, these impacts are expected to manifest themselves over varying time horizons.

Because the combustion of natural gas produces lower GHG emissions per unit of energy than competing fossil fuels, cap-and-trade legislation or EPA regulatory initiatives such as the Clean Power Plan or Affordable Clean Energy rule could stimulate demand for natural gas by increasing the relative cost of competing fuels such as coal and oil. In addition, we anticipate that GHG regulations will increase demand for carbon sequestration technologies, such as the techniques we have successfully demonstrated in our enhanced oil recovery operations within our CO_2 business segment. However, these potential positive effects on our markets may be offset if these same regulations also cause the cost of natural gas to increase relative to competing non-fossil fuels. Although we currently cannot predict the magnitude and direction of these impacts, GHG regulations could have material adverse effects on our business, financial position, results of operations or cash flows.

Department of Homeland Security

The Department of Homeland Security, referred to in this report as the DHS, has regulatory authority over security at certain high-risk chemical facilities. The DHS has promulgated the Chemical Facility Anti-Terrorism Standards and required all high-risk chemical and industrial facilities, including oil and gas facilities, to comply with the regulatory requirements of these standards. This process includes completing security vulnerability assessments, developing site security plans, and implementing protective measures necessary to meet DHS-defined, risk-based performance standards. The DHS has not provided final notice to all facilities that it determines to be high risk and subject to the rule; therefore, neither the extent to which our facilities may be subject to coverage by the rules nor the associated costs to comply can currently be determined, but it is possible that such costs could be substantial.

Human Capital

In managing our human capital resources, we use a strategic approach to building a diverse, inclusive, and respectful workplace. Our human resources department 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 employed 10,524 full-time personnel at December 31, 2020, including approximately 929 full-time hourly personnel at certain terminals and pipelines covered by collective bargaining agreements that expire between 2021 and 2024. We consider relations with our employees to be good.

We value the safety of our workforce and integrate a culture of safety, emergency preparedness, and environmental responsibility through our operations management system (OMS). Our OMS conforms to common industry standards and establishes a framework that helps us: (i) provide employees and contractors with a safe work environment; (ii) comply with laws, rules, regulations, policies, and procedures; and (iii) identify opportunities to improve. Although our ultimate target is zero incidents, we also have three non-zero employee safety performance targets. The first is to outperform the annual industry average total recordable incident rate (TRIR). The second is to outperform our own three-year TRIR average. The third is a longer-term target to improve our company-wide employee TRIR from 1.0 in the baseline year 2019 to 0.7 by 2024. We seek to constantly improve our contractor TRIR performance through initiatives to address recent incident trends and new best practices.

Our board of directors' nominating and governance committee is responsible for planning for succession in the senior management ranks of the Company, including the office of chief executive officer. The chief executive officer shall report to the Committee, generally at the time of the regularly scheduled third quarter board of directors meeting in each year, regarding the processes in place to identify talent within and outside the Company to succeed to senior management positions and the information developed during the current calendar year pursuant to those processes.

We consider employee diversity an asset and support equal opportunity employment. We take affirmative action to employ and advance in employment all persons without regard to their race/ethnicity; sex; sexual orientation; gender, including gender identity and expression; veteran status; disability; or other protected categories, and base employment decisions solely on valid job requirements.

We prohibit discrimination or harassment against any employee or applicant on the basis of race/ethnicity, sex, or other protected categories listed within our code of business conduct and ethics. We are committed to a harassment free workplace, supported with online and face-to-face workplace harassment and discrimination prevention training for our employees. In 2019, renewal training on our harassment and discrimination prevention policy was provided to our supervisors and employees. This renewal training highlighted supervisor's and employee's responsibilities for maintaining a workplace free of harassment. We continued to provide this training to newly hired or promoted supervisors and employees in 2020.

As part of the 2020 annual succession planning efforts, we focused on identifying minority and female candidates for senior positions. Management reviewed its succession plan, including a discussion on development opportunities for potential successors, with the nominating and governance committee of our board of directors at its meeting in July 2020.

Our employees are an integral part of our success and we value their career development. We encourage and support professional development and learning for our employees by offering workforce training, tuition reimbursement, leadership and other development programs. These programs help improve recruitment, development, and retention. We support our employees' ongoing career goals and development through several programs. These programs help maximize our employees' potential and give them the skills they need to further enhance their careers.

Our compensation program is linked to long and short-term strategic financial and operational objectives, including environmental, safety, and compliance targets. Compensation includes competitive base salaries in the markets in which we operate and competitive benefits, including retirement plans, opportunities for annual bonuses, and, for eligible employees, long-term incentives and an employee stock purchase plan.

Refer to "*COVID-19*" included in Item 7, "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" for information on actions taken by the Company in response to the COVID-19 pandemic.

Properties and Rights of Way

We believe that we generally have satisfactory title to the properties we own and use in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions, which do not materially detract from the value of such property, the interests in those properties or the use of such properties in our businesses. Our terminals, storage facilities, treating and processing plants, regulator and compressor stations, oil and gas wells, offices and related facilities are located on real property owned or leased by us. In some cases, the real property we lease is on federal, state or local government land.

We generally do not own the land on which our pipelines are constructed. Instead, we obtain and maintain rights to construct and operate the pipelines on other people's land generally under agreements that are perpetual or provide for renewal rights. Substantially all of our pipelines are constructed on rights-of-way granted by the apparent record owners of such property. In many instances, lands over which rights-of-way have been obtained are subject to prior liens that have not been subordinated to the right-of-way grants. In some cases, not all of the apparent record owners have joined in the right-of-way grants, but in substantially all such cases, signatures of the owners of a majority of the interests have been obtained. Permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets and state highways, and in some instances, such permits are revocable at the election of the grantor, or, the pipeline may be required to move its facilities at its own expense. Permits also have been obtained from railroad companies to run along or cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election. Some such permits require annual or other periodic payments. In a few minor cases, property for pipeline purposes was purchased by the Company.

Financial Information about Geographic Areas

For geographic information concerning our assets and operations, see Note 16 "*Reportable Segments*" to our consolidated financial statements.

Available Information

We make available free of charge on or through our internet website, at www.kindermorgan.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. The information contained on or connected to our internet website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

Item 1A. *Risk Factors.*

You should carefully consider the risks described below, in addition to the other information contained in this document. Realization of any of the following risks could have a material adverse effect on our business, financial condition, cash flows and results of operations.

Risks Related to Operating our Business

The COVID-19 pandemic has adversely affected, and could continue to adversely affect, our business.

The COVID-19 pandemic and the efforts to control it have resulted in a significant decline in global economic activity and significant disruption of global supply chains. Governments around the world have implemented stringent measures to help reduce the spread of the virus, including stay-at-home orders, business and school closures, travel restrictions and other measures. The resulting downturn in economic activity has negatively impacted global demand and prices for crude oil, natural gas, NGL, refined petroleum products, CO_2, steel, chemicals and other products that we handle in our pipelines, terminals, shipping vessels and other facilities. See Item 2. "*Management's Discussion and Analysis of Financial Condition and Results of Operations—General—COVID-19.*" Continuing uncertainty regarding the global impact of COVID-19 is likely to result in continued weakness in demand and prices for the products on which our business depends.

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. In addition, measures taken by regulatory authorities attempting to mitigate the economic consequences of COVID-19 may not be effective or may have unintended harmful consequences. 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 potential impact of COVID-19 on our business and operations. COVID-19 may materially adversely affect our business, results of operations, financial condition and cash flows. 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 pandemic may have the effect of heightening many of the other risks we face.

Our businesses are dependent on the supply of and demand for the products that we handle.

Our pipelines, terminals and other assets and facilities, including the availability of expansion opportunities, depend in part on continued production of natural gas, crude oil and other products in the geographic areas that they serve. Our business also depends in part on the levels of demand for natural gas, crude oil, NGL, refined petroleum products, CO_2, steel, chemicals and other products in the geographic areas to which our pipelines, terminals, shipping vessels and other facilities deliver or provide service, and the ability and willingness of our shippers and other customers to supply such demand. For example, without additions to crude oil and gas reserves, production will decline over time as reserves are depleted, and production costs may rise. Producers may reduce or shut down production during times of lower product prices or higher production costs to the extent they become uneconomic. Producers in areas served by us may not be successful in exploring for and developing additional reserves, and our pipelines and related facilities may not be able to maintain existing volumes of throughput.

Commodity prices and tax incentives may not remain at levels that encourage producers to explore for and develop additional reserves, produce existing marginal reserves or renew transportation contracts as they expire. Additionally, demand for such products can decline due to situations over which we have no control, such as the COVID-19 pandemic and various measures that federal, state and local authorities have implemented in response to the virus or its economic consequences. See "*—The COVID-19 pandemic has adversely affected, and could continue to adversely affect, our business.*"

In addition to economic disruptions resulting from events such as COVID-19, conditions in the business environment generally, such as declining or sustained low commodity prices, supply disruptions, or higher development or production costs, could result in a slowing of supply to our pipelines, terminals and other assets. Also, sustained lower demand for hydrocarbons, or changes in the regulatory environment or applicable governmental policies, including in relation to climate change or other environmental concerns, may have a negative impact on the supply of crude oil and other products. In recent years, a number of initiatives and regulatory changes relating to reducing GHG emissions have been undertaken by federal, state and municipal governments and crude oil and gas industry participants. In addition, public concern about the potential risks posed by climate change has resulted in increased demand for energy efficiency and a transition to energy provided from renewable energy sources, rather than fossil fuels, fuel-efficient alternatives such as hybrid and electric vehicles, and pursuit of other technologies to reduce GHG emissions, such as carbon capture and sequestration. We may see an intensification of these trends if and to the extent that the new U.S. presidential administration succeeds in enacting its energy and environmental policies.

These factors could result in not only increased costs for producers of hydrocarbons but also an overall decrease in the demand for hydrocarbons. Each of the foregoing could negatively impact our business directly as well as our shippers and other customers, which in turn could negatively impact our prospects for new contracts for transportation, terminaling or other midstream services, or renewals of existing contracts or the ability of our customers and shippers to honor their contractual commitments. Furthermore, such unfavorable conditions may compound the adverse effects of larger disruptions such as COVID-19. See "*—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us*" below.

We cannot predict the impact of future economic conditions, fuel conservation measures, alternative fuel requirements, governmental regulation or technological advances in fuel economy and energy generation devices, all of which could reduce the production of and/or demand for the products we handle. In addition, irrespective of supply of or demand for products we handle, implementation of new regulations or changes to existing regulations affecting the energy industry could have a material adverse effect on us.

We face competition from other pipelines and terminals, as well as other forms of transportation and storage.

Competition is a factor affecting our existing businesses and our ability to secure new project opportunities. Any current or future pipeline system or other form of transportation (such as barge, rail or truck) that delivers the products we handle into the areas that our pipelines serve could offer transportation services that are more desirable to shippers than those we provide because of price, location, facilities or other factors. Likewise, competing terminals or other storage options may become more attractive to our customers. To the extent that competitors offer the markets we serve more desirable transportation or storage options, or customers opt to construct their own facilities for services previously provided by us, this could result in unused capacity on our pipelines and in our terminals. We also could experience competition for the supply of the products we handle from both existing and proposed pipeline systems; for example, several pipelines access many of the same areas of supply as our pipeline systems and transport to destinations not served by us. If capacity on our assets remains unused, our ability to re-contract for expiring capacity at favorable rates or otherwise retain existing customers could be impaired. In addition, to the extent that companies pursuing development of carbon capture and sequestration technology are successful, they could compete with us for customers who purchase CO_2 for use in enhanced oil recovery operations.

The volatility of crude oil, NGL and natural gas prices could adversely affect our CO_2 business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments.

The revenues, cash flows, profitability and future growth of some of our businesses (and the carrying values of certain of their respective assets, which include related goodwill) depend to a large degree on prevailing crude oil, NGL and natural gas prices.

Prices for crude oil, NGL and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for crude oil, NGL and natural gas, uncertainties within the market and a variety of other factors beyond our control. These factors include, among other things (i) weather conditions and events such as hurricanes in the U.S.; (ii) domestic and global economic conditions; (iii) the activities of the OPEC and other countries that are significant producers of crude oil ("OPEC+"); (iv) governmental regulation; (v) political instability in crude oil producing countries; (vi) the foreign supply of and demand for crude oil and natural gas; (vii) the price of foreign imports; (viii) the proximity and availability of storage and transportation infrastructure and processing and treating facilities; and (ix) the availability and prices of alternative fuel sources. We use hedging arrangements to partially mitigate our exposure to commodity prices, but these arrangements also are subject to inherent risks. We are also subject, indirectly, to volatility of commodity prices, through many of our customers' direct exposure to such volatility. Please read *"—Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.*"

In 2020, the impact of COVID-19, combined with a dispute regarding production levels among OPEC+ countries, caused crude oil prices to reach historic lows. By March 2020, crude oil was priced at less than $25 per barrel, the lowest price since April 1999. Producers in the U.S. and globally did not reduce crude oil production at a rate sufficient to match the dramatic decline in economic activity that accelerated in March and April 2020, resulting in an oversupply of crude oil that caused the per-barrel price to fall below zero in April 2020. While global oil demand has improved from the low levels experienced during these months last year and OPEC+ agreed on production cuts in April 2020, there is no assurance that demand will not decline to these levels again, that the OPEC+ agreement will continue to be observed by its parties or that the agreed production cuts will be sufficient to offset continuing demand weakness. Downward pressure on commodity prices could continue for the foreseeable future. If prices fall substantially or remain low for a sustained period and we are not sufficiently protected through hedging arrangements, we may be unable to realize a profit from these businesses and would operate at a loss.

Sharp declines in the prices of crude oil, NGL or natural gas (such as we experienced in the first half of 2020) or a prolonged unfavorable price environment, may result in a commensurate reduction in our revenues, income and cash flows from our businesses that produce, process, or purchase and sell crude oil, NGL, or natural gas, and could have a material adverse effect on the carrying value (which includes assigned goodwill) of our CO_2 business segment's proved reserves, certain assets in certain midstream businesses within our Natural Gas Pipelines business segment, and certain assets within our Products Pipelines business segment. For example, following the commodity price declines we experienced during the first half of 2020, we recorded a combined $1.950 billion of non-cash impairments associated with our Natural Gas Pipelines Non-Regulated and CO_2 reporting units, primarily for impairments of goodwill and assets owned in these businesses. See Note 3 "*Impairments and Losses and Gains on Divestitures*" and Note 8 "*Goodwill*" to our consolidated financial statements for more information.

In recent decades, there have been periods worldwide of both overproduction and underproduction of hydrocarbons, and periods of both increased and relaxed energy conservation efforts. Such conditions have resulted in periods of excess supply of, and reduced demand for, crude oil on a worldwide basis and for natural gas on a domestic basis. These periods have been followed by periods of short supply of, and increased demand for, crude oil and natural gas. The cycles of excess or short supply of crude oil or natural gas have placed pressures on prices and resulted in dramatic price fluctuations even during relatively short periods of seasonal market demand. These fluctuations impact the accuracy of assumptions used in our budgeting process. For more information about our energy and commodity market risk, see Item 7A "*Quantitative and Qualitative Disclosures About Market Risk*."

Commodity transportation and storage activities involve numerous risks that may result in accidents or otherwise adversely affect our operations.

There are a variety of hazards and operating risks inherent to the transportation and storage of the products we handle, such as leaks; releases; the breakdown, underperformance or failure of equipment, facilities, information systems or processes; damage to our pipelines caused by third-party construction; the compromise of information and control systems; spills at terminals and hubs; spills associated with the loading and unloading of harmful substances at rail facilities; adverse sea conditions (including storms and rising sea levels) and releases or spills from our shipping vessels or vessels loaded at our marine terminals; operator error; labor disputes/work stoppages; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries on which our assets depend; and catastrophic events or natural disasters such as fires, floods, explosions, earthquakes, acts of terrorists and saboteurs, cyber security breaches, and other similar events, many of which are beyond our control. Additional risks to our vessels include capsizing, grounding and navigation errors.

The occurrence of any of these risks could result in serious injury and loss of human life, significant damage to property and natural resources, environmental pollution, significant reputational damage, impairment or suspension of operations, fines or other regulatory penalties, and revocation of regulatory approvals or imposition of new requirements, any of which also could result in substantial financial losses, including lost revenue and cash flow to the extent that an incident causes an interruption of service. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks may be greater. In addition, the consequences of any operational incident (including as a result of adverse sea conditions) at one of our marine terminals may be even more significant as a result of the complexities involved in addressing leaks and releases occurring in the ocean or along coastlines and/or the repair of marine terminals.

Our operating results may be adversely affected by unfavorable economic and market conditions.

As described above, COVID-19 has resulted in a downturn of economic activity on a global scale. The slowdown resulting from the pandemic has affected numerous industries, including the crude oil and gas industry, the steel industry and in specific segments and markets in which we operate, resulting in reduced demand and increased price competition for our products and services. We could experience similar or compounded adverse impacts as a result of other global events affecting economic conditions. In addition, uncertain or changing economic conditions within one or more geographic regions may affect our operating results within the affected regions. Sustained unfavorable commodity prices, volatility in commodity prices or changes in markets for a given commodity might also have a negative impact on many of our customers, which could impair their ability to meet their obligations to us. See *"—Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us."* In addition, decreases in the prices of crude oil, NGL and natural gas are likely to have a negative impact on our operating results and cash flow. See *"—The volatility of crude oil, NGL and natural gas prices could adversely affect our CO_2 business segment and businesses within our Natural Gas Pipelines and Products Pipelines business segments."*

If economic and market conditions (including volatility in commodity markets) globally, in the U.S. or in other key markets become more volatile or continue to deteriorate, we may experience material impacts on our business, financial condition and results of operations.

Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

We are exposed to the risk of loss in the event of nonperformance by our customers or other counterparties, such as hedging counterparties, joint venture partners and suppliers. The global economic slowdown caused by COVID-19, and the coinciding extreme drop in crude oil prices, which was exacerbated by the effects of the pandemic, significantly impacted the financial condition of many companies, particularly exploration and production companies, including some of our customers or counterparties. Many of our counterparties finance their activities through cash flow from operations or debt or equity financing, and some of them may be highly leveraged and may not be able to access additional capital to sustain their operations in the future. Our counterparties are subject to their own operating, market, financial and regulatory risks, and some are experiencing, or may experience in the future, severe financial problems that have had or may have a significant impact on their creditworthiness. Crude oil, NGL and natural gas prices were all lower on average in 2020 compared to 2019. Further deterioration in crude oil prices, or a continuation of the existing low natural gas or NGL price environment, would likely cause severe financial distress to some of our customers with direct commodity price exposure and may result in additional customer bankruptcies. Further, the security that is permitted to be obtained from such customers may be limited, including by FERC regulation. While certain of our customers are subsidiaries of an entity that has an investment grade credit rating, in many cases the parent entity has not guaranteed the obligations of the subsidiary and, therefore, the parent's credit ratings may have no bearing on such customers' ability to pay us for the services we provide or otherwise fulfill their obligations to us. See Note 2 "*Summary of Significant Accounting Policies—Allowance for Credit Losses*" in our consolidated financial statements.

Furthermore, financially distressed customers might be forced to reduce or curtail their future use of our products and services, which also could have a material adverse effect on our results of operations, financial condition, and cash flows.

We cannot provide any assurance that such customers and key counterparties will not become financially distressed or that such financially distressed customers or counterparties will not default on their obligations to us or file for bankruptcy protection. If one of such customers or counterparties files for bankruptcy protection, we likely would be unable to collect all, or even a significant portion of, amounts owed to us. Similarly, our contracts with such customers may be renegotiated at lower rates or terminated altogether. Significant customer and other counterparty defaults and bankruptcy filings could have a material adverse effect on our business, financial position, results of operations or cash flows.

We are subject to reputational risks and risks relating to public opinion.

Our business, operations or financial condition generally may be negatively impacted as a result of negative public opinion. Public opinion may be influenced by negative portrayals of the industry in which we operate as well as opposition to development projects. In addition, market events specific to us could result in the deterioration of our reputation with key stakeholders. Potential impacts of negative public opinion or reputational issues may include delays or stoppages in expansion projects, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support from regulatory authorities, challenges to regulatory approvals, difficulty securing financing for and cost overruns affecting expansion projects and the degradation of our business generally.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the energy industry, particularly other energy infrastructure providers, over which we have no control. In particular, our reputation could be impacted by negative publicity related to pipeline incidents or unpopular expansion projects and due to opposition to development of hydrocarbons and energy infrastructure, particularly projects involving resources that are considered to increase GHG emissions and contribute to climate change. Negative impacts from a compromised reputation or changes in public opinion (including with respect to the production, transportation and use of hydrocarbons generally) could include revenue loss, reduction in customer base, delays in obtaining, or challenges to, regulatory approvals with respect to growth projects and decreased value of our securities and our business.

The future success of our oil and gas development and production operations depends in part upon our ability to develop additional oil and gas reserves that are economically recoverable.

The rate of production from oil and natural gas properties declines as reserves are depleted. Without successful development activities, the reserves, revenues and cash flows of the oil and gas producing assets within our CO_2 business segment will decline. We may not be able to develop or acquire additional reserves at an acceptable cost or have necessary financing for these activities in the future. Additionally, if we do not realize production volumes greater than, or equal to, our hedged volumes, we may suffer financial losses not offset by physical transactions.

The development of crude oil and gas properties involves risks that may result in a total loss of investment.

The business of developing and operating oil and gas properties involves a high degree of business and financial risk that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Acquisition and development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on the investment. A variety of geological, operational and market-related factors, including, but not limited to, unusual or unexpected geological formations, pressures, equipment failures or accidents, fires, explosions, blowouts, cratering, pollution and other environmental risks, shortages or delays in the availability of drilling rigs and the delivery of equipment, loss of circulation of drilling fluids or other conditions, may substantially delay or prevent completion of any well or otherwise prevent a property or well from being profitable. A productive well may become uneconomic in the event water or other deleterious substances are encountered, which impair or prevent the production of oil and/or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other deleterious substances.

Our use of hedging arrangements does not eliminate our exposure to commodity price risks and could result in financial losses or volatility in our income.

We engage in hedging arrangements to reduce our direct exposure to fluctuations in the prices of crude oil, natural gas and NGL, including differentials between regional markets. These hedging arrangements expose us to risk of financial loss in some circumstances, including when production is less than expected, when the counterparty to the hedging contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the hedging agreement and the actual price received. In addition, these hedging arrangements may limit the benefit we would otherwise receive from increases in prices for crude oil, natural gas and NGL. Furthermore, our hedging arrangements cannot hedge against any decrease in the volumes of products we handle. See "*—Our businesses are dependent on the supply of and demand for the products that we handle.*"

The markets for instruments we use to hedge our commodity price exposure generally reflect then-prevailing conditions in the underlying commodity markets. As our existing hedges expire, we will seek to replace them with new hedging arrangements. To the extent then-existing underlying market conditions are unfavorable, new hedging arrangements available to us will reflect such unfavorable conditions, limiting our ability to hedge our exposure to unfavorable commodity prices.

The accounting standards regarding hedge accounting are very complex, and even when we engage in hedging transactions (for example, to mitigate our exposure to fluctuations in commodity prices or currency exchange rates or to balance our exposure to fixed and variable interest rates) that are effective economically, these transactions may not be considered effective for accounting purposes. Accordingly, our consolidated financial statements may reflect some volatility due to these hedges, even when there is no underlying economic impact at the dates of those consolidated financial statements. In addition, it may not be possible for us to engage in hedging transactions that completely eliminate our exposure to commodity prices; therefore, our consolidated financial statements may reflect a gain or loss arising from an exposure to commodity prices for which we are unable to enter into a completely effective hedge. For more information about our hedging activities, see Item 7, "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Critical Accounting Policies and Estimates—Hedging Activities*" and Note 14 "*Risk Management*" to our consolidated financial statements.

A breach of information security or failure of one or more key information technology or operational (IT) systems, or those of third parties, may adversely affect our business, results of operations or business reputation.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. Some of the operational systems we use are owned or operated by independent third-party vendors. The various uses of these IT systems, networks and services include, but are not limited to, controlling our pipelines and terminals with industrial control systems, collecting and storing information and data, processing transactions, and handling other processing necessary to manage our business.

While we have implemented and maintain a cybersecurity program designed to protect our IT and data systems from such attacks, we can provide no assurance that our cybersecurity program will be effective. In compliance with state and local stay-at-home orders issued in connection with COVID-19, a number of our employees have transitioned to working from home. As a result, more of our employees are working from locations where our cybersecurity program may be less effective and IT security may be less robust. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. The risk of a disruption or breach of our operational systems, or the compromise of the data processed in connection with our operations, through an act of terrorism or cyber sabotage event has increased as attempted attacks have advanced in sophistication and number around the world.

If any of our systems are damaged, fail to function properly or otherwise become unavailable, we may incur substantial costs to repair or replace them and may experience loss or corruption of critical data and interruptions or delays in our ability to perform critical functions, which could adversely affect our business and results of operations. A significant failure, compromise, breach or interruption in our systems, which may result from problems such as malware, computer viruses, hacking attempts or third-party error or malfeasance, could result in a disruption of our operations, customer dissatisfaction, damage to our reputation and a loss of customers or revenues. Efforts by us and our vendors to develop, implement and maintain security measures, including malware and anti-virus software and controls, may not be successful in preventing these events from occurring, and any network and information systems-related events could require us to expend significant resources to remedy such event. In the future, we may be required to expend additional resources to continue to enhance our information security measures and/or to investigate and remediate information security vulnerabilities.

Attacks, including acts of terrorism or cyber sabotage, or the threat of such attacks, may adversely affect our business or reputation.

The U.S. government has issued public warnings that indicate that pipelines and other infrastructure assets might be specific targets of terrorist organizations or "cyber sabotage" events. For example, in 2018, a cyber attack on a shared data network forced four U.S. natural gas pipeline operators to temporarily shut down computer communications with their customers. Potential targets include our pipeline systems, terminals, processing plants or operating systems. The occurrence of an attack could cause a substantial decrease in revenues and cash flows, increased costs to respond or other financial loss, damage to our reputation, increased regulation or litigation or inaccurate information reported from our operations. There is no assurance that adequate cyber sabotage and terrorism insurance will be available at rates we believe are reasonable in the near future. These developments may subject our operations to increased risks, as well as increased costs, and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations and financial condition or could harm our business reputation.

Hurricanes, earthquakes, flooding and other natural disasters, as well as subsidence and coastal erosion and climate-related physical risks, could have an adverse effect on our business, financial condition and results of operations.

Some of our pipelines, terminals and other assets are located in, and our shipping vessels operate in, areas that are susceptible to hurricanes, earthquakes, flooding and other natural disasters or could be impacted by subsidence and coastal erosion. These natural disasters and phenomena could potentially damage or destroy our assets and disrupt the supply of the products we transport. Many climate models indicate that global warming is likely to result in rising sea levels, increased intensity of weather, and increased frequency of extreme precipitation and flooding. These climate-related changes could result in damage to physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions. In addition, we may experience increased insurance premiums and deductibles, or a decrease in available coverage, for our assets in areas subject to severe weather. Natural disasters and phenomena can similarly affect the facilities of our customers. In either case, losses could exceed our insurance coverage and our business, financial condition and results of operations could be adversely affected, perhaps materially. See Items 1 and 2 "*Business and Properties—Narrative Description of Business—Environmental Matters*."

Our insurance policies do not cover all losses, costs or liabilities that we may experience, and insurance companies that currently insure companies in the energy industry may cease to do so or substantially increase premiums.

Our insurance program may not cover all operational risks and costs and may not provide sufficient coverage in the event of a claim. We do not maintain insurance coverage against all potential losses and could suffer losses for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Losses in excess of our insurance coverage could have a material adverse effect on our business, financial condition and results of operations.

Changes in the insurance markets subsequent to certain hurricanes and natural disasters have made it more difficult and more expensive to obtain certain types of coverage. The occurrence of an event that is not fully covered by insurance, or failure by one or more of our insurers to honor its coverage commitments for an insured event, could have a material adverse effect on our business, financial condition and results of operations. Insurance companies may reduce the insurance capacity they are willing to offer or may demand significantly higher premiums or deductibles to cover our assets. If significant changes in the number or financial solvency of insurance underwriters for the energy industry occur, we may be unable to obtain and maintain adequate insurance at a reasonable cost. There is no assurance that our insurers will renew their insurance coverage on acceptable terms, if at all, or that we will be able to arrange for adequate alternative coverage in the event of non-renewal. The unavailability of full insurance coverage to cover events in which we suffer significant losses could have a material adverse effect on our business, financial condition and results of operations.

Expanding our existing assets and constructing new assets is part of our growth strategy. Our ability to begin and complete construction on expansion and new-build projects may be inhibited by difficulties in obtaining, or our inability to obtain, permits and rights-of-way, as well as public opposition, increases in costs of construction materials, cost overruns, inclement weather and other delays. Should we pursue expansion of or construction of new projects through joint ventures with others, we will share control of and any benefits from those projects.

We regularly undertake major construction projects to expand our existing assets and to construct new assets. New growth projects generally will be subject to, among other things, the receipt of regulatory approvals, feasibility and cost analyses, funding availability and industry, market and demand conditions. If we pursue joint ventures with third parties, those parties may share approval rights over major decisions, and may act in their own interests. Their views may differ from our own or our views of the interests of the venture which could result in operational delays or impasses, which in turn could affect the financial expectations of and our expected benefits from the venture. A variety of factors outside of our control, such as difficulties in obtaining permits and rights-of-way or other regulatory approvals, have caused, and may continue to cause, delays in or cancellations of our construction projects. Regulatory authorities may modify their permitting policies in ways that disadvantage our construction projects, such as the FERC's consideration of changes to its Certificate Policy Statement. Such factors can be exacerbated by public opposition to our projects. See "*—We are subject to reputational risks and risks relating to public opinion.*" For example, changing public attitudes toward pipelines bearing fossil fuels may impede our ability to secure rights-of-way or governmental reviews and authorizations on a timely basis or at all. Inclement weather, natural disasters and delays in performance by third-party contractors have also resulted in, and may continue to result in, increased costs or delays in construction. Significant increases in costs of construction materials, cost overruns or delays, or our inability to obtain a required permit or right-of-way, could have a material adverse effect on our return on investment, results of operations and cash flows, and could result in project cancellations or limit our ability to pursue other growth opportunities.

Substantially all of the land on which our pipelines are located is owned by third parties. If we are unable to procure and maintain access to land owned by third parties, our revenue and operating costs, and our ability to complete construction projects, could be adversely affected.

We must obtain and maintain the rights to construct and operate pipelines on other owners' land, including private landowners, railroads, public utilities and others. While our interstate natural gas pipelines in the U.S. have federal eminent domain authority, the availability of eminent domain authority for our other pipelines varies from state to state depending upon the type of pipeline—petroleum liquids, natural gas, CO_2, or crude oil—and the laws of the particular state. In any case, we must compensate landowners for the use of their property, and in eminent domain actions, such compensation may be determined by a court. If we are unable to obtain rights-of-way on acceptable terms, our ability to complete construction projects on time, on budget, or at all, could be adversely affected. In addition, we are subject to the possibility of increased costs under our right-of-way or rental agreements with landowners, primarily through renewals of expiring agreements and rental increases. If we were to lose these rights, our operations could be disrupted or we could be required to relocate the affected pipelines, which could cause a substantial decrease in our revenues and cash flows and a substantial increase in our costs.

The acquisition of additional businesses and assets is part of our growth strategy. We may experience difficulties completing acquisitions or integrating new businesses and properties, and we may be unable to achieve the benefits we expect from any future acquisitions.

Part of our business strategy includes acquiring additional businesses and assets. We evaluate and pursue assets and businesses that we believe will complement or expand our operations in accordance with our growth strategy. We cannot provide any assurance that we will be able to complete acquisitions in the future or achieve the desired results from any acquisitions we do complete. Any acquired business or assets will be subject to many of the same risks as our existing businesses and may not achieve the levels of performance that we anticipate.

If we do not successfully integrate acquisitions, we may not realize anticipated operating advantages and cost savings. Integration of acquired companies or assets involves a number of risks, including (i) the loss of key customers of the acquired business; (ii) demands on management related to the increase in our size; (iii) the diversion of management's attention from the management of daily operations; (iv) difficulties in implementing or unanticipated costs of accounting, budgeting, reporting, internal controls and other systems; and (v) difficulties in the retention and assimilation of necessary employees.

We may not be able to maintain the levels of operating efficiency that acquired companies have achieved or might achieve separately. Successful integration of each acquisition will depend upon our ability to manage those operations and to eliminate redundant and excess costs. Difficulties in integration may be magnified if we make multiple acquisitions over a relatively short period of time. Because of difficulties in combining and expanding operations, we may not be able to achieve the cost savings and other size-related benefits that we hoped to achieve after these acquisitions, which would harm our financial condition and results of operations.

Our business requires the retention and recruitment of a skilled workforce, and difficulties recruiting and retaining our workforce could result in a failure to implement our business plans.

Our operations and management require the retention and recruitment of a skilled workforce, including engineers, technical personnel and other professionals. We and our affiliates compete with other companies in the energy industry for this skilled workforce. In addition, many of our current employees are retirement eligible and have significant institutional knowledge that must be transferred to other employees. If we are unable to (i) retain current employees; (ii) successfully complete the knowledge transfer; and/or (iii) recruit new employees of comparable knowledge and experience, our business could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

If we are unable to retain our executive officers, our ability to execute our business strategy, including our growth strategy, may be hindered.

Our success depends in part on the performance of and our ability to retain our executive officers, particularly Richard D. Kinder, our Executive Chairman and one of our founders, Steve Kean, our Chief Executive Officer, and Kim Dang, our President. Along with the other members of our senior management, Messrs. Kinder and Kean and Ms. Dang have been responsible for developing and executing our growth strategy. If we are not successful in retaining Mr. Kinder, Mr. Kean, Ms. Dang or our other executive officers, or replacing them, our business, financial condition or results of operations could be adversely affected. We do not maintain key personnel insurance.

Risks Related to Financing Our Business

Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions.

As of December 31, 2020, we had approximately $33.4 billion of consolidated debt (excluding debt fair value adjustments). Additionally, we and substantially all of our wholly owned U.S. subsidiaries are parties to a cross guarantee agreement under which each party to the agreement unconditionally guarantees the indebtedness of each other party, which means that we are liable for the debt of each of such subsidiaries. This level of consolidated debt and the cross guarantee agreement could have important consequences, such as (i) limiting our ability to obtain additional financing to fund our working capital, capital expenditures, debt service requirements or potential growth, or for other purposes; (ii) increasing the cost of our future borrowings; (iii) limiting our ability to use operating cash flow in other areas of our business or to pay dividends because we must dedicate a substantial portion of these funds to make payments on our debt; (iv) placing us at a competitive disadvantage compared to competitors with less debt; and (v) increasing our vulnerability to adverse economic and industry conditions.

Our ability to service our consolidated debt, and our ability to meet our consolidated leverage targets, 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, many of which are beyond our control. If our consolidated cash flow is not sufficient to service our consolidated debt, and any future indebtedness that we incur, we will be forced to take actions such as reducing dividends, reducing or delaying our business activities, acquisitions, investments or capital expenditures, selling assets or seeking additional equity capital. We may also take such actions to reduce our indebtedness if we determine that our earnings (or consolidated EBITDA, as calculated in accordance with our revolving credit facility) may not be sufficient to meet our consolidated leverage targets or to comply with consolidated leverage ratios required under certain of our debt agreements. We may not be able to effect any of these actions on satisfactory terms or at all. For more information about our debt, see Note 9 "*Debt*" to our consolidated financial statements.

Our business, financial condition and operating results may be affected adversely by increased costs of capital or a reduction in the availability of credit.

Adverse changes to the availability, terms and cost of capital, interest rates or our credit ratings (which would have a corresponding impact on the credit ratings of our subsidiaries that are party to the cross guarantee agreement) could cause our cost of doing business to increase by limiting our access to capital, including our ability to refinance maturities of existing indebtedness on similar terms, which could in turn reduce our cash flows and limit our ability to pursue acquisition or expansion opportunities. Our credit ratings may be impacted by our leverage, liquidity, credit profile and potential transactions. Although the ratings from credit agencies are not recommendations to buy, sell or hold our securities, our credit ratings will generally affect the market value of our and our subsidiaries' debt securities and the terms available to us for future issuances of debt securities.

Also, disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability, impacting our ability to finance our operations on favorable terms. A significant reduction in the availability of credit could materially and adversely affect our business, financial condition and results of operations.

Our and our customers' access to capital could be affected by evolving financial institutions' policies concerning businesses linked to fossil fuels.

Our and our customers' access to capital could be affected by financial institutions' evolving policies concerning businesses linked to fossil fuels. Public opinion toward industries linked to fossil fuels continues to evolve. Concerns about the potential effects of climate change have caused some to direct their attention towards sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in such companies. Ultimately, this could make it more difficult for our customers to secure funding for exploration and production activities or for us to secure funding for growth projects, and consequently could both indirectly affect demand for our services and directly affect our ability to fund construction or other capital projects.

Our large amount of variable rate debt makes us vulnerable to increases in interest rates.

As of December 31, 2020, approximately $5.2 billion of our approximately $33.4 billion of consolidated debt (excluding debt fair value adjustments) was subject to variable interest rates, either as short-term or long-term variable-rate debt obligations, or as long-term fixed-rate debt effectively converted to variable rates through the use of interest rate swaps. Our interest rate swaps as of December 31, 2020 include $2.5 billion of variable-to-fixed interest rate swap agreements and $900 million of fixed-to-variable interest rate swap agreements that expire during 2021. Should interest rates increase, the amount of cash required to service variable-rate debt would increase, as would our costs to refinance maturities of existing indebtedness, and our earnings and cash flows could be adversely affected.

For more information about our interest rate risk, see Item 7A "*Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.*"

Acquisitions and growth capital expenditures may require access to external capital. Limitations on our access to external financing sources could impair our ability to grow.

We have limited amounts of internally generated cash flows to fund acquisitions and growth capital expenditures. If our internally generated cash flows are not sufficient to fund one or more capital projects or acquisitions, we may have to rely on external financing sources, including commercial borrowings and issuances of debt and equity securities, to fund our acquisitions and growth capital expenditures. Limitations on our access to external financing sources, whether due to tightened capital markets, more expensive capital or otherwise, could impair our ability to execute our growth strategy.

Our debt instruments may limit our financial flexibility and increase our financing costs.

The instruments governing our debt contain restrictive covenants that may prevent us from engaging in certain transactions that may be beneficial to us. Some of the agreements governing our debt generally require us to comply with various affirmative and negative covenants, including the maintenance of certain financial ratios and restrictions on (i) incurring additional debt; (ii) entering into mergers, consolidations and sales of assets; (iii) granting liens; and (iv) entering into sale-leaseback transactions. The instruments governing any future debt may contain similar or more limiting restrictions. Our ability to respond to changes in business and economic conditions and to obtain additional financing, if needed, may be restricted.

Risks Related to Regulation

The FERC or state public utility commissions, such as the CPUC, may establish pipeline tariff rates that have a negative impact on us. In addition, the FERC, state public utility commissions or our customers could initiate proceedings or file complaints challenging the tariff rates charged by our pipelines, which could have an adverse impact on us.

The profitability of our regulated pipelines is influenced by fluctuations in costs and our ability to recover any increases in our costs in the rates charged to our shippers. To the extent that our costs increase in an amount greater than what we are permitted by the FERC or state public utility commissions to recover in our rates, or to the extent that there is a lag before we can file for and obtain rate increases, such events can have a negative impact on our operating results.

Our existing rates may also be challenged by complaint. Regulators and shippers on our pipelines have rights to challenge, and have challenged, the rates we charge under certain circumstances prescribed by applicable regulations. Some shippers on our pipelines have filed complaints with the regulators that seek substantial refunds for alleged overcharges during the years in question and prospective reductions in the tariff rates. Further, the FERC may continue to initiate investigations to determine whether interstate natural gas pipelines have over-collected on rates charged to shippers. We may face challenges, similar to those described in Note 18 "*Litigation and Environmental*" to our consolidated financial statements, to the rates we charge on our pipelines. Any successful challenge to our rates could materially adversely affect our future earnings, cash flows and financial condition.

New laws, policies, regulations, rulemaking and oversight, as well as changes to those currently in effect, could adversely impact our earnings, cash flows and operations.

Our assets and operations are subject to regulation and oversight by federal, state and local regulatory authorities. Legislative changes, as well as regulatory actions taken by these agencies, have the potential to adversely affect our profitability. Additional regulatory burdens and uncertainties will be created if and to the extent that the new U.S. presidential administration succeeds in enacting more stringent energy and environmental policies. For example, on January 27, 2021, the President issued an executive order directing, among other matters, the reevaluation of the leasing program for federally managed lands and the "pause" of new oil and natural gas leases on public lands pending completion of the review. These and other initiatives of the new presidential administration may affect our assets and operations directly or indirectly, such as by preventing or delaying the exploration for and production of natural gas and liquids that we transport.

Regulation affects almost every part of our business and extends to such matters as (i) federal, state and local taxation; (ii) rates (which include tax, reservation, commodity, surcharges, fuel and gas lost and unaccounted for), operating terms and conditions of service; (iii) the types of services we may offer to our customers; (iv) the contracts for service entered into with our customers; (v) the certification and construction of new facilities; (vi) the costs of raw materials, such as steel, which may be affected by tariffs or otherwise; (vii) the integrity, safety and security of facilities and operations; (viii) acquisitions or dispositions of assets or businesses; (ix) the acquisition, extension, disposition or abandonment of services or facilities; (x) reporting and information posting requirements; (xi) the maintenance of accounts and records; and (xii) relationships with affiliated companies involved in various aspects of the energy businesses.

Should we fail to comply with any applicable statutes, rules, regulations, and orders of regulatory authorities, we could be subject to substantial penalties and fines and potential loss of government contracts. Furthermore, new laws, regulations or policy changes sometimes arise from unexpected sources. New laws or regulations, unexpected policy changes or interpretations of existing laws or regulations, applicable to our income, operations, assets or another aspect of our business, could have a material adverse impact on our earnings, cash flow, financial condition and results of operations. For more information, see Items 1 and 2 "*Business and Properties—Narrative Description of Business—Industry Regulation*."

Environmental, health and safety laws and regulations could expose us to significant costs and liabilities.

Our operations are subject to federal, state and local laws, regulations and potential liabilities arising under or relating to the protection or preservation of the environment, natural resources and human health and safety. Such laws and regulations affect many aspects of our past, present and future operations, and generally require us to obtain and comply with various environmental registrations, licenses, permits, inspections and other approvals. Liability under such laws and regulations may be incurred without regard to fault under CERCLA, the Resource Conservation and Recovery Act, the Federal Clean Water Act, the Oil Pollution Act or analogous state laws as a result of the presence or release of hydrocarbons and other hazardous substances into or through the environment, and these laws may require response actions and remediation and may impose liability for natural resource and other damages. Private parties, including the owners of properties through which our pipelines pass, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with such laws and regulations or for personal injury or property damage. Our insurance may not cover all environmental risks and costs and/or may not provide sufficient coverage in the event an environmental claim is made against us.

Failure to comply with these laws and regulations including required permits and other approvals also may expose us to civil, criminal and administrative fines, penalties and/or interruptions in our operations that could harm our business, financial position, results of operations and prospects. For example, if an accidental leak, release or spill of liquid petroleum products, chemicals or other hazardous substances occurs at or from our pipelines, shipping vessels or storage or other facilities, we may experience significant operational disruptions and we may have to pay a significant amount to clean up or otherwise respond to the leak, release or spill, pay government penalties, address natural resource damage, compensate for human exposure or property damage, install costly pollution control equipment or undertake a combination of these and other measures. The resulting costs and liabilities could materially and negatively affect our earnings and cash flows.

We own and/or operate numerous properties and equipment that have been used for many years in connection with our business activities. While we believe we have utilized operating, handling and disposal practices that were consistent with industry practices at the time, hydrocarbons or other hazardous substances may have been released at or from properties and equipment owned, operated or used by us or our predecessors, or at or from properties where our or our predecessors' wastes have been taken for disposal. In addition, many of these properties have been owned and/or operated by third parties whose management, handling and disposal of hydrocarbons or other hazardous substances were not under our control. These properties and the hazardous substances released and wastes disposed on them may be subject to laws in the U.S. such as CERCLA, which impose joint and several liability without regard to fault or the legality of the original conduct. Under such laws and implementing regulations, we could be required to remove or remediate previously disposed wastes or property contamination, including contamination caused by prior owners or operators. Imposition of such liability schemes could have a material adverse impact on our operations and financial position.

Further, we cannot ensure that such existing laws and regulations will not be revised or that new laws or regulations will not be adopted or become applicable to us. For example, the Federal Clean Air Act and other similar federal and state laws are subject to periodic review and amendment, which could result in more stringent emission control requirements obligating us to make significant capital expenditures at our facilities. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects. For more information, see Items 1 and 2 "*Business and Properties—Narrative Description of Business—Environmental Matters.*"

Increased regulatory requirements relating to the integrity of our pipelines may require us to incur significant capital and operating expense outlays to comply.

We are subject to extensive laws and regulations related to pipeline integrity at the federal and state level. There are, for example, federal guidelines issued by the U.S. Department of Transportation (DOT) for pipeline companies in the areas of operations, testing, education, training and communication. The ultimate costs of compliance with the integrity management rules are difficult to predict. The majority of compliance costs relate to pipeline integrity testing and repairs. Technological advances in in-line inspection tools, identification of additional threats to a pipeline's integrity and changes to the amount of pipeline determined to be located in "High Consequence Areas" can have a significant impact on integrity testing and repair costs. We plan to continue our integrity testing programs to assess and maintain the integrity of our existing and future pipelines as required by the DOT rules. The results of these tests could cause us to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operation of our pipelines.

Further, additional laws and regulations that may be enacted in the future or a new interpretation of existing laws and regulations could significantly increase the amount of these expenditures. There can be no assurance as to the amount or timing of future expenditures for pipeline integrity regulation, and actual future expenditures may be different from the amounts we currently anticipate. Revised or additional regulations that result in increased compliance costs or additional operating restrictions, particularly if those costs are not deemed by regulators to be fully recoverable from our customers, could have a material adverse effect on our business, financial position, results of operations and prospects.

Climate-related risk and related regulation could result in significantly increased operating and capital costs for us and could reduce demand for our products and services.

Various laws and regulations exist or are under development that seek to regulate the emission of GHGs such as methane and CO_2, including the EPA programs to control GHG emissions and state actions to develop statewide or regional programs. Existing EPA regulations require us to report GHG emissions in the U.S. from sources such as our larger natural gas compressor stations, fractionated NGL, and production of naturally occurring CO_2 (for example, from our McElmo Dome CO_2 field), even when such production is not emitted to the atmosphere. Proposed approaches to further address GHG emissions include establishing GHG "cap and trade" programs, increased efficiency standards, participation in international climate agreements, issuance of executive orders by the U.S. presidential administration and incentives or mandates for pollution reduction, use of renewable energy sources, or use of alternative fuels with lower carbon content. For more information about climate change regulation, see Items 1 and 2 "*Business and Properties—Narrative Description of Business—Environmental Matters—Climate Change.*"

Adoption of any such laws or regulations could increase our costs to operate and maintain our facilities and could require us to install new emission controls on our facilities, acquire allowances for our GHG emissions, pay taxes related to our GHG emissions and administer and manage a GHG emissions program, and such increased costs could be significant. Recovery of such increased costs from our customers is uncertain in all cases and may depend on events beyond our control, including the outcome of future rate proceedings before the FERC. Such laws or regulations could also lead to reduced demand for hydrocarbon products that are deemed to contribute to GHGs, or restrictions on their use, which in turn could adversely affect demand for our products and services.

Finally, many climate models indicate that global warming is likely to result in rising sea levels and increased frequency and severity of weather events, which may lead to higher insurance costs, or a decrease in available coverage, for our assets in areas subject to severe weather. These climate-related changes could result in damage to our physical assets, especially operations located in low-lying areas near coasts and river banks, and facilities situated in hurricane-prone and rain-susceptible regions.

Any of the foregoing could have adverse effects on our business, financial position, results of operations or cash flows.

Increased regulation of exploration and production activities, including activity on public lands and hydraulic fracturing, could result in reductions or delays in drilling and completing new oil and natural gas wells, as well as reductions in production from existing wells, which could adversely impact the volumes of natural gas transported on our natural gas pipelines and our own oil and gas development and production activities.

We gather, process or transport crude oil, natural gas or NGL from several areas, including lands that are federally managed. Policy and regulatory initiatives of the new presidential administration or legislation by Congress may decrease access to federally managed lands and increase the regulatory burdens associated with using these lands to produce crude oil or natural gas. For example, on January 20, 2021, the Secretary of the Department of the Interior issued an order temporarily restricting the authorization of new leases or permits to drill without the approval of a senior Department official. On January 27, 2021, the President issued an executive order directing, among other matters, the reevaluation of the leasing program for federally managed lands and the "pause" of new oil and natural gas leases on public lands pending completion of the review.

The use of hydraulic fracturing is prevalent in areas where we have operations. Oil and gas development and production activities are subject to numerous federal, state and local laws and regulations relating to environmental quality and pollution control. The oil and gas industry is increasingly relying on supplies of hydrocarbons from unconventional sources, such as shale, tight sands and coal bed methane. The extraction of hydrocarbons from these sources frequently requires hydraulic fracturing. Hydraulic fracturing involves the pressurized injection of water, sand, and chemicals into the geologic formation to stimulate gas production and is a commonly used stimulation process employed by oil and gas exploration and production operators in the completion of certain oil and gas wells. There have been initiatives at the federal and state levels to regulate or otherwise restrict the use of hydraulic fracturing. Adoption of legislation or regulations placing restrictions on hydraulic fracturing activities could impose operational delays, increased operating costs and additional regulatory burdens on exploration and production operators, which could reduce their production of crude oil, natural gas or NGL and, in turn, adversely affect our revenues, cash flows and results of operations by decreasing the volumes of these commodities that we handle.

In addition, many states are promulgating stricter requirements related not only to well development but also to compressor stations and other facilities in the oil and gas industry sector. These laws and regulations increase the costs of these activities and may prevent or delay the commencement or continuance of a given operation. Specifically, these activities are subject to laws and regulations regarding the acquisition of permits before drilling, restrictions on drilling activities and location, emissions into the environment, water discharges, transportation of hazardous materials, and storage and disposition of wastes. In addition, legislation has been enacted that requires well and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. These laws and regulations may adversely affect our oil and gas development and production activities.

The Jones Act includes restrictions on ownership by non-U.S. citizens of our U.S. point to point maritime shipping vessels, and failure to comply with the Jones Act, or changes to or a repeal of the Jones Act, could limit our ability to operate our vessels in the U.S. coastwise trade, result in the forfeiture of our vessels or otherwise adversely impact our earnings, cash flows and operations.

We are subject to the Jones Act, which generally restricts U.S. point-to-point maritime shipping to vessels operating under the U.S. flag, built in the U.S., owned and operated by U.S.-organized companies that are controlled and at least 75% owned by U.S. citizens and crewed by predominately U.S. citizens. Our business would be adversely affected if we fail to comply with the Jones Act provisions on coastwise trade. If we do not comply with any of these requirements, we would be prohibited from operating our vessels in the U.S. coastwise trade and, under certain circumstances, we could be deemed to have undertaken an unapproved transfer to non-U.S. citizens that could result in severe penalties, including permanent loss of U.S. coastwise trading rights for our vessels, fines or forfeiture of vessels. Our business could be adversely affected if the Jones Act were to be modified or repealed so as to permit foreign competition that is not subject to the same U.S. government imposed burdens.

Risks Related to Ownership of Our Capital Stock

The guidance we provide for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business.

We disclose in this report and elsewhere the expected cash dividends on our common stock. These reflect our current judgment, but as with any estimate, they may be affected by inaccurate assumptions and other risks and uncertainties, many of which are beyond our control. See "*Information Regarding Forward-Looking Statements*" at the beginning of this report. If our board of directors elects to pay dividends at the anticipated level and that action would leave us with insufficient cash to take timely advantage of growth opportunities (including through acquisitions), to meet any large unanticipated liquidity requirements, to fund our operations, to maintain our leverage metrics or otherwise to address properly our business prospects, our business could be harmed.

Conversely, a decision to address such needs might lead to the payment of dividends below the anticipated levels. As events present themselves or become reasonably foreseeable, our board of directors, which determines our business strategy and our dividends, may decide to address those matters by reducing our anticipated dividends. Alternatively, because nothing in our governing documents or credit agreements prohibits us from borrowing to pay dividends, we could choose to incur debt to enable us to pay our anticipated dividends. This would add to our substantial debt discussed above under "*—Risks Related to Financing Our Business—Our substantial debt could adversely affect our financial health and make us more vulnerable to adverse economic conditions*."

Our certificate of incorporation restricts the ownership of our common stock by non-U.S. citizens within the meaning of the Jones Act. These restrictions may affect the liquidity of our common stock and may result in non-U.S. citizens being required to sell their shares at a loss.

The Jones Act requires, among other things, that at least 75% of our common stock be owned at all times by U.S. citizens, as defined under the Jones Act, in order for us to own and operate vessels in the U.S. coastwise trade. As a safeguard to help us maintain our status as a U.S. citizen, our certificate of incorporation provides that, if the number of shares of our common stock owned by non-U.S. citizens exceeds 22%, we have the ability to redeem shares owned by non-U.S. citizens to reduce the percentage of shares owned by non-U.S. citizens to 22%. These redemption provisions may adversely impact the marketability of our common stock, particularly in markets outside of the U.S. Further, those stockholders would not have control over the timing of such redemption, and may be subject to redemption at a time when the market price or timing of the redemption is disadvantageous. In addition, the redemption provisions might have the effect of impeding or discouraging a merger, tender offer or proxy contest by a non-U.S. citizen, even if it were favorable to the interests of some or all of our stockholders.

Item 1B. *Unresolved Staff Comments.*

None.

Item 3. *Legal Proceedings.*

See Note 18 *"Litigation and Environmental"* to our consolidated financial statements.

Item 4. *Mine Safety Disclosures.*

We no longer own or operate mines for which reporting requirements apply under the mine safety disclosure requirements of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank), except for one terminal that is in temporary idle status with the Mine Safety and Health Administration. We have not received any specified health and safety violations, orders or citations, related assessments or legal actions, mining-related fatalities, or similar events requiring disclosure pursuant to the mine safety disclosure requirements of Dodd-Frank for the year ended December 31, 2020.

PART II

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

As of February 4, 2021, we had 10,594 holders of our Class P common stock, which does not include beneficial owners whose shares are held by a nominee, such as a broker or bank.

For information on our equity compensation plans, see Note 10 "*Share-based Compensation and Employee Benefits—Share-based Compensation*" to our consolidated financial statements.

Item 6. ***Selected Financial Data.***

The following table sets forth, for the periods and at the dates indicated, our summary historical financial data. The table is derived from our consolidated financial statements and notes thereto, and should be read in conjunction with those audited financial statements. See also Item 7 *"Management's Discussion and Analysis of Financial Condition and Results of Operations"* in this report for more information.

Five-Year Review
Kinder Morgan, Inc. and Subsidiaries

	As of or for the Year Ended December 31,				
	2020	**2019**	**2018**	**2017**	**2016**
	(In millions, except per share amounts)				
Income and Cash Flow Data:					
Revenues	$ 11,700	$ 13,209	$ 14,144	$ 13,705	$ 13,058
Operating income	1,560	4,873	3,794	3,529	3,538
Earnings (losses) from equity investments	780	101	617	428	(113)
Net income	180	2,239	1,919	223	721
Net income attributable to Kinder Morgan, Inc.	119	2,190	1,609	183	708
Net income available to common stockholders	119	2,190	1,481	27	552
Class P Shares					
Basic Earnings Per Common Share From Continuing Operations	$ 0.05	$ 0.96	$ 0.66	$ 0.01	$ 0.25
Basic Weighted Average Common Shares Outstanding	2,263	2,264	2,216	2,230	2,230
Dividends per common share declared for the period(a)	$ 1.05	$ 1.00	$ 0.80	$ 0.50	$ 0.50
Dividends per common share paid in the period(a)	1.0375	0.95	0.725	0.50	0.50
Balance Sheet Data (at end of period):					
Property, plant and equipment, net	$ 35,836	$ 36,419	$ 37,897	$ 40,155	$ 38,705
Total assets	71,973	74,157	78,866	79,055	80,305
Current portion of debt	2,558	2,477	3,388	2,828	2,696
Long-term debt(b)	30,838	30,883	33,205	34,088	36,205

(a) Dividends for the fourth quarter of each year are declared and paid during the first quarter of the following year.
(b) Excludes debt fair value adjustments.

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 our consolidated financial statements and the notes thereto. We prepared our consolidated financial statements in accordance with GAAP. Additional sections in this report which should be helpful to the reading of our discussion and analysis include the following: (i) a description of our business strategy found in Items 1 and 2 "*Business and Properties—Narrative Description of Business—Business Strategy;*" (ii) a description of developments during 2020, found in Items 1 and 2 "*Business and Properties—General Development of Business—Recent Developments;*" (iii) a description of risk factors affecting us and our business, found in Item 1A "*Risk Factors;*" and (iv) a discussion of forward-looking statements, found in "*Information Regarding Forward-Looking Statements*" at the beginning of this report.

A comparative discussion of our 2019 to 2018 operating results can be found in Item 7 "*Management's Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations*" included in our Annual Report on Form 10-K for the year ended December 31, 2019 filed with the SEC on February 7, 2020.

General

As an energy infrastructure owner and operator in multiple facets of the various U.S. energy industries and markets, we examine a number of variables and factors on a routine basis to evaluate our current performance and our prospects for the future. We have four business segments as further described below.

Natural Gas Pipelines

This segment owns and operates (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas gathering systems and processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG regasification, liquefaction and storage facilities.

With respect to our interstate natural gas pipelines, related storage facilities and LNG terminals, the revenues from these assets are primarily received under long-term fixed contracts. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate risk of reduced volumes and prices by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. These long-term contracts are typically structured with a fixed fee reserving the right to transport or store natural gas and specify that we receive the majority of our fee for making the capacity available, whether or not the customer actually chooses to utilize the capacity. Similarly, our Texas Intrastate natural gas pipeline operations, currently derives approximately 83% of its sales and transport margins from long-term transport and sales contracts. As contracts expire, we have additional exposure to the longer term trends in supply and demand for natural gas. As of December 31, 2020, the remaining weighted average contract life of our natural gas transportation contracts held by assets we own and have equity interests in (including intrastate pipelines' sales portfolio) was approximately six years. Our LNG regasification and liquefaction and associated storage contracts are subscribed under long-term agreements with a weighted average remaining contract life of approximately 13 years.

Our midstream assets provide natural gas gathering and processing services. These assets are mostly fee-based and the revenues and earnings we realize from gathering natural gas, processing natural gas in order to remove NGL from the natural gas stream, and fractionating NGL into its base components, are affected by the volumes of natural gas made available to our systems. Such volumes are impacted by producer rig count and drilling activity. In addition to fee-based arrangements, some of which may include minimum volume commitments, we also provide some services based on percent-of-proceeds, percent-of-index and keep-whole contracts. Our service contracts may rely solely on a single type of arrangement, but more often they combine elements of two or more of the above, which helps us and our counterparties manage the extent to which each shares in the potential risks and benefits of changing commodity prices.

Products Pipelines

This segment owns and operates refined petroleum products, crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, crude oil and condensate to various markets. This segment also owns and/or operates associated product terminals and petroleum pipeline transmix facilities.

The profitability of our refined petroleum products pipeline transportation business generally is driven by the volume of refined petroleum products that we transport and the prices we receive for our services. We also have 49 liquids terminals in this business segment that store fuels and offer blending services for ethanol and biodiesel. The transportation and storage volume levels are primarily driven by the demand for the refined petroleum products being shipped or stored. Demand for refined petroleum products tends to track in large measure demographic and economic growth, and, with the exception of periods of time with very high product prices or recessionary conditions, demand tends to be relatively stable. Because of that, we seek to own refined petroleum products pipelines and terminals located in, or that transport to, stable or growing markets and population centers. The prices for shipping are generally based on regulated tariffs that are adjusted annually based on changes in the U.S. Producer Price Index and a FERC index rate.

Our crude, condensate and refined petroleum products transportation services are primarily provided pursuant to (i) either FERC or state tariffs and (ii) long-term contracts that normally contain minimum volume commitments. As a result of these contracts, our settlement volumes are generally not sensitive to changing market conditions in the shorter term; however, the revenues and earnings we realize from our pipelines and terminals are affected by the volumes of crude oil, refined petroleum products and condensate available to our pipeline systems, which are impacted by the level of oil and gas drilling activity and product demand in the respective regions that we serve. Our petroleum condensate processing facility splits condensate into its various components, such as light and heavy naphtha, under a long-term fee-based agreement with a major integrated oil company.

Terminals

This segment owns and operates (i) liquids and bulk terminal facilities located throughout the U.S. that store and handle various commodities including gasoline, diesel fuel, chemicals, ethanol, metals and petroleum coke; and (ii) Jones Act-qualified tankers.

The factors impacting our Terminals business segment generally differ between liquid and bulk terminals, and in the case of a bulk terminal, the type of product being handled or stored. Our liquids terminals business generally has long-term contracts that require the customer to pay regardless of whether they use the capacity. Thus, similar to our natural gas pipelines business, our liquids terminals business is less sensitive to short-term changes in supply and demand. Therefore, the extent to which changes in these variables affect our terminals business in the near term is a function of the length of the underlying service contracts (which on average is approximately three years), the extent to which revenues under the contracts are a function of the amount of product stored or transported, and the extent to which such contracts expire during any given period of time.

As with our refined petroleum products pipelines transportation business, the revenues from our bulk terminals business are generally driven by the volumes we handle and/or store, as well as the prices we receive for our services, which in turn are driven by the demand for the products being shipped or stored. While we handle and store a large variety of products in our bulk terminals, the primary products are petroleum coke, metals and ores. In addition, the majority of our contracts for this business contain minimum volume guarantees and/or service exclusivity arrangements under which customers are required to utilize our terminals for all or a specified percentage of their handling and storage needs. The profitability of our minimum volume contracts is generally unaffected by short-term variation in economic conditions; however, to the extent we expect volumes above the minimum and/or have contracts which are volume-based, we can be sensitive to changing market conditions. To the extent practicable and economically feasible in light of our strategic plans and other factors, we generally attempt to mitigate the risk of reduced volumes and pricing by negotiating contracts with longer terms, with higher per-unit pricing and for a greater percentage of our available capacity. In addition, weather-related events, including hurricanes, may impact our facilities and access to them and, thus, the profitability of certain terminals for limited periods of time or, in relatively rare cases of severe damage to facilities, for longer periods.

In addition to liquid and bulk terminals, we also own Jones Act-qualified tankers in our Terminals business segment. As of December 31, 2020, we have sixteen Jones Act-qualified tankers that operate in the marine transportation of crude oil, condensate and refined products in the U.S. and are primarily operating pursuant to multi-year fixed price charters with major integrated oil companies, major refiners and the U.S. Military Sealift Command.

CO_2

This segment (i) manages the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) owns interests in and/or operates oil fields and gasoline processing plants in West Texas; and (iii) owns and operates a crude oil pipeline system in West Texas.

The CO_2 source and transportation business primarily has third-party contracts with minimum volume requirements, which as of December 31, 2020, had a remaining average contract life of approximately eight years. CO_2 sales contracts vary from customer to customer and have evolved over time as supply and demand conditions have changed. Our recent contracts have generally provided for a delivered price tied to the price of crude oil, but with a floor price. On a volume-weighted basis, for third-party contracts making deliveries in 2020, and utilizing the average oil price per barrel contained in our 2021 budget, approximately 100% of our revenue is based on a fixed fee or floor price. Our success in this portion of the CO_2 business segment can be impacted by the demand for CO_2. In the CO_2 business segment's oil and gas producing activities, we monitor the amount of capital we expend in relation to the amount of production that we expect to add. The revenues we receive from our crude oil and NGL sales are affected by the prices we realize from the sale of these products. Over the long-term, we will tend to receive prices that are dictated by the demand and overall market price for these products. In the shorter term, however, market prices are likely not indicative of the revenues we will receive due to our risk management, or hedging, program, in which the prices to be realized for certain of our future sales quantities are fixed, capped or bracketed through the use of financial derivative contracts, particularly for crude oil. The realized weighted average crude oil price per barrel, with the hedges allocated to oil, was $53.78 per barrel in 2020 and $49.49 per barrel in 2019. Had we not used energy derivative contracts to transfer commodity price risk, our crude oil sales prices would have averaged $38.32 per barrel in 2020 and $55.12 per barrel in 2019.

Also, see Note 15 *"Revenue Recognition"* to our consolidated financial statements for more information about the types of contracts and revenues recognized for each of our segments.

Sale of U.S. Portion of Cochin Pipeline System and KML

On December 16, 2019, we closed on two cross-conditional transactions resulting in the sale of the U.S. portion of the Cochin Pipeline system and all the outstanding equity of KML, including our 70% interest, to Pembina Pipeline Corporation (Pembina) (together, the "KML and U.S. Cochin Sale"). We received approximately 25 million shares of Pembina common equity for our interest in KML. On January 9, 2020, we sold our shares of Pembina and received proceeds of approximately $907 million ($764 million after tax) which were used to repay maturing debt. The assets sold were part of our Natural Gas Pipelines and Terminals business segments.

COVID-19

The COVID-19 pandemic-related reduction in energy demand and the dramatic decline in commodity prices that began to impact us in the first quarter of 2020 continued to cause disruptions and volatility. Sharp declines in crude oil and natural gas production along with reduced demand for refined products due to the economic shutdown in the wake of the pandemic affected our business and continues to do so. While we have seen some meaningful recovery during the second half of the year in demand for refined products that we move through our terminals, significant uncertainty remains regarding the duration and extent of the impact of the pandemic on the energy industry, including demand and prices for the products handled by our pipelines, terminals, shipping vessels and other facilities, although we expect to see further recovery as vaccines are distributed and more normal societal activity resumes.

The events as described above resulted in decreases of current and estimated long-term crude oil and NGL sale prices and volumes we expect to realize and in significant reductions to the market capitalization of many midstream and oil and gas producing companies. These events triggered us to review the carrying value of our long-lived assets and recoverability of goodwill for interim periods in addition to our annual testing. Our evaluations resulted in the recognition during the first six months of 2020 of a $350 million impairment for long-lived assets in our CO_2 business segment and goodwill impairments of $1,000 million and $600 million to our Natural Gas Pipelines Non-Regulated and CO_2 reporting units, respectively. For a further discussion of these impairments and our risk for future impairments, see Note 3, "*Impairments and Losses and Gains on Divestitures*."

We have placed a priority on protecting our employees during this pandemic while continuing to provide essential services to our customers. We continue to follow the Centers for Disease Control guidelines for those employees that perform essential tasks in our operations and have taken a cautious enterprise-wide approach with a phased return to workplace process for our employees who are currently working remotely. During 2020, our incremental employee safety costs associated with COVID-19 mitigation were approximately $15 million, primarily for personal protective equipment, enhanced cleaning protocols, temperature screening and other measures we adopted to protect our employees. We continue to operate our assets safely and efficiently during this challenging period.

2021 Dividends and Discretionary Capital

We expect to declare dividends of $1.08 per share for 2021, a 3% increase from the 2020 declared dividends of $1.05 per share. We also expect to invest $0.8 billion in expansion projects and contributions to joint ventures during 2021.

The expectations for 2021 discussed above involve risks, uncertainties and assumptions, and are not guarantees of performance. Many of the factors that will determine these expectations are beyond our ability to control or predict, and because of these uncertainties, it is advisable not to put undue reliance on any forward-looking statement. Please read our Item 1A "*Risk Factors*" below and "*Information Regarding Forward-Looking Statements*" at the beginning of this report for more information. Furthermore, we plan to provide updates to these 2021 expectations when we believe previously disclosed expectations no longer have a reasonable basis.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining: (i) revenue recognition; (ii) income taxes; (iii) the economic useful lives of our assets and related depletion rates; (iv) the fair values used in (a) calculations of possible asset and equity investment impairment charges, and (b) calculation for the annual goodwill impairment test (or interim tests if triggered); (v) reserves for environmental claims, legal fees, transportation rate cases and other litigation liabilities; (vi) provisions for credit losses; (vii) computation of the gain or loss, if any, on assets sold in whole or in part; and (viii) exposures under contractual indemnifications.

For a summary of our significant accounting policies, see Note 2 *"Summary of Significant Accounting Policies"* to our consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Environmental Matters

With respect to our environmental exposure, we utilize both internal staff and external experts to assist us in identifying environmental issues and in estimating the costs and timing of remediation efforts. We expense or capitalize, as appropriate, environmental expenditures that relate to current operations, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, we do not discount environmental liabilities to a net present value, and we recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at fair value, where appropriate, environmental liabilities assumed in a business combination.

Our accrual of environmental liabilities often coincides either with our completion of a feasibility study or our commitment to a formal plan of action, but generally, we recognize and/or adjust our probable environmental liabilities, if necessary or appropriate, following quarterly reviews of potential environmental issues and claims that could impact our assets or operations. In recording and adjusting environmental liabilities, we consider the effect of environmental compliance, pending legal actions against us, and potential third party liability claims. For more information on environmental matters, see Part I, Items 1 and 2 "*Business and Properties—Narrative Description of Business—Environmental Matters.*" For more information on our environmental disclosures, see Note 18 *"Litigation and Environmental"* to our consolidated financial statements.

Legal and Regulatory Matters

Many of our operations are regulated by various U.S. regulatory bodies, and we are subject to legal and regulatory matters as a result of our business operations and transactions. We utilize both internal and external counsel in evaluating our potential exposure to adverse outcomes from orders, judgments or settlements. In general, we expense legal costs as incurred. When we identify contingent liabilities that are probable, we identify a range of possible costs expected to be required to resolve the matter. Generally, if no amount within this range is a better estimate than any other amount, we record a liability equal to the low end of the range. Any such liability recorded is revised as better information becomes available. Accordingly, to the extent that actual outcomes differ from our estimates, or additional facts and circumstances cause us to revise our estimates, our earnings will be affected. For more information on legal proceedings, see Note 18 *"Litigation and Environmental"* to our consolidated financial statements.

Long-lived Asset and Equity Investment Impairments

We evaluate long-lived assets including leases and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group. If the carrying value of a long-lived asset or asset group is in excess of undiscounted cash flows, we typically use discounted cash flow analyses to determine if an impairment is required.

For more information on our long-lived asset impairments and significant estimates and assumptions used in our evaluations, see Note 3 *"Impairments and Losses and Gains on Divestitures."*

Intangible Assets

Intangible assets are those assets which provide future economic benefit but have no physical substance. Identifiable intangible assets having indefinite useful economic lives, including goodwill, are not subject to regular periodic amortization, and such assets are not to be amortized until their lives are determined to be finite. Instead, the carrying amount of a recognized intangible asset with an indefinite useful life must be tested for impairment annually or on an interim basis if events or circumstances indicate that the fair value of the asset has decreased below its carrying value. We evaluate goodwill for impairment on May 31 of each year. At year end and during other interim periods we evaluate our reporting units for events and changes that could indicate that it is more likely than not that the fair value of a reporting unit could be less than its carrying amount.

Excluding goodwill, our other intangible assets include customer contracts and relationships and agreements. These intangible assets have definite lives, are being amortized in a systematic and rational manner over their estimated useful lives, and are reported separately as "Other intangibles, net" in our accompanying consolidated balance sheets.

For more information on our 2020 goodwill impairment evaluations and amortizable intangibles, see Note 3 *"Impairments and Losses and Gains on Divestitures"* and Note 8 *"Goodwill"* to our consolidated financial statements.

Hedging Activities

We engage in a hedging program that utilizes derivative contracts to mitigate (offset) our exposure to fluctuations in energy commodity prices, foreign currency exposure on Euro-denominated debt, and until our recent divestitures of our Canadian assets, net investments in foreign operations, and to balance our exposure to fixed and variable interest rates, and we believe that these derivative contracts are, or were in respect to our Canadian operations, generally effective in realizing these objectives. According to the provisions of GAAP, to be considered effective, changes in the value of a derivative contract or its resulting cash flows must substantially offset changes in the value or cash flows of the hedged risk, and any component excluded from the computation of the effectiveness of the derivative contract must be recognized in earnings over the life of the hedging instrument by using a systematic and rational method.

All of our derivative contracts are recorded at estimated fair value. We utilize published prices, broker quotes, and estimates of market prices to estimate the fair value of these contracts; however, actual amounts could vary materially from estimated fair values as a result of changes in market prices. In addition, changes in the methods used to determine the fair value of these contracts could have a material effect on our results of operations. We do not anticipate future changes in the methods used to determine the fair value of these derivative contracts. For more information on our hedging activities, see Note 14 *"Risk Management"* to our consolidated financial statements.

Employee Benefit Plans

We reflect an asset or liability for our pension and other postretirement benefit (OPEB) plans based on their overfunded or underfunded status. As of December 31, 2020, our pension plans were underfunded by $645 million, and our OPEB plans were overfunded by $62 million. Our pension and OPEB obligations and net benefit costs are primarily based on actuarial calculations. We use various assumptions in performing these calculations, including those related to the return that we expect to earn on our plan assets, the rate at which we expect the compensation of our employees to increase over the plan term, the estimated cost of health care when benefits are provided under our plan and other factors. A significant assumption we utilize is the discount rate used in calculating our benefit obligations. We utilize a full yield curve approach in the estimation of the service and interest cost components of net periodic benefit cost (credit) for our pension and OPEB plans which applies the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The selection of these assumptions is further discussed in Note 10 *"Share-based Compensation and Employee Benefits"* to our consolidated financial statements.

Actual results may differ from the assumptions included in these calculations, and as a result, our estimates associated with our pension and OPEB can be, and have been revised in subsequent periods. The income statement impact of the changes in the assumptions on our related benefit obligations are deferred and amortized into income over either the period of expected future service of active participants, or over the expected future lives of inactive plan participants. As of December 31, 2020, we had deferred net losses of approximately $521 million in pre-tax accumulated other comprehensive loss related to our pension and OPEB plans.

The following sensitivity analysis shows the estimated impact of a 1% change in the primary assumptions used in our actuarial calculations associated with our pension and OPEB plans for the year ended December 31, 2020:

	Pension Benefits		**OPEB**	
	Net benefit cost (income)	**Change in funded status(a)**	**Net benefit cost (income)**	**Change in funded status(a)**
	(In millions)			
One percent increase in:				
Discount rates	$ (11)	$ 215	$ —	$ 21
Expected return on plan assets	(20)	—	(3)	—
Rate of compensation increase	3	(12)	—	—
One percent decrease in:				
Discount rates	12	(253)	—	(24)
Expected return on plan assets	20	—	3	—
Rate of compensation increase	(2)	11	—	—

(a) Includes amounts deferred as either accumulated other comprehensive income (loss) or as a regulatory asset or liability for certain of our regulated operations.

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are enacted. We do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is more likely than not to not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments, including KMI's investment in its wholly-owned subsidiary, KMP.

Results of Operations

Overview

As described in further detail below, our management evaluates our performance primarily using the GAAP financial measures of Segment EBDA (as presented in Note 16, "*Reportable Segments*"), net income and net income attributable to Kinder Morgan, Inc., along with the non-GAAP financial measures of Adjusted Earnings and DCF, both in the aggregate and per share for each, Adjusted Segment EBDA, Adjusted EBITDA, Net Debt and Net Debt to Adjusted EBITDA.

GAAP Financial Measures

The Consolidated Earnings Results for the years ended December 31, 2020 and 2019 present Segment EBDA, net income and net income attributable to Kinder Morgan, Inc. which are prepared and presented in accordance with GAAP. Segment EBDA is a useful measure of our operating performance because it measures the operating results of our segments before DD&A and certain expenses that are generally not controllable by our business segment operating managers, such as general and administrative expenses and corporate charges, interest expense, net, and income taxes. Our general and administrative expenses and corporate charges include such items as unallocated employee benefits, insurance, rentals, unallocated litigation and environmental expenses, and shared corporate services including accounting, information technology, human resources and legal services.

Non-GAAP Financial Measures

Our non-GAAP financial measures described below should not be considered alternatives to GAAP net income or other GAAP measures and have important limitations as analytical tools. Our computations of these non-GAAP financial measures may differ from similarly titled measures used by others. You should not consider these non-GAAP financial measures in isolation or as substitutes for an analysis of our results as reported under GAAP. Management compensates for the limitations of these non-GAAP financial measures by reviewing our comparable GAAP measures, understanding the differences between the measures and taking this information into account in its analysis and its decision making processes.

Certain Items

Certain Items, as adjustments used to calculate our non-GAAP financial measures, are items that are required by GAAP to be reflected in net income, but typically either (i) do not have a cash impact (for example, asset impairments), or (ii) by their nature are separately identifiable from our normal business operations and in our view are likely to occur only sporadically (for example, certain legal settlements, enactment of new tax legislation and casualty losses). We also include adjustments related to joint ventures (see "Amounts from Joint Ventures" below and the tables included in *"—Consolidated Earnings Results (GAAP)—Certain Items Affecting Consolidated Earnings Results," "—Non-GAAP Financial Measures—Reconciliation of Net Income (GAAP) to Adjusted EBITDA" and "—Non-GAAP Financial Measures—Supplemental Information"* below). In addition, Certain Items are described in more detail in the footnotes to tables included in *"—Segment Earnings Results"* and *"—DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests"* below.

Adjusted Earnings

Adjusted Earnings is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items. Adjusted Earnings is used by us and certain external users of our financial statements to assess the earnings of our business excluding Certain Items as another reflection of our ability to generate earnings. We believe the GAAP measure most directly comparable to Adjusted Earnings is net income attributable to Kinder Morgan, Inc. Adjusted Earnings per share uses Adjusted Earnings and applies the same two-class method used in arriving at basic earnings per common share. See *"—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF"* below.

DCF

DCF is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items (Adjusted Earnings), and further by DD&A and amortization of excess cost of equity investments, income tax expense, cash taxes, sustaining capital expenditures and other items. We also include amounts from joint ventures for income taxes, DD&A and sustaining capital expenditures (see "Amounts from Joint Ventures" below). DCF is a significant performance measure useful to management and external users of our financial statements in evaluating our performance and in measuring and estimating the ability of our assets to generate cash earnings after servicing our debt, paying cash taxes and expending sustaining capital, that could be used for discretionary purposes such as common stock dividends, stock repurchases, retirement of debt, or expansion capital expenditures. DCF should not be used as an alternative to net cash provided by operating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is net income attributable to Kinder Morgan, Inc. DCF per common share is DCF divided by average outstanding common shares, including restricted stock awards that participate in common share dividends. See *"—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF"* and *"—Adjusted Segment EBDA to Adjusted EBITDA to DCF"* below.

Adjusted Segment EBDA

Adjusted Segment EBDA is calculated by adjusting Segment EBDA for Certain Items attributable to the segment. Adjusted Segment EBDA is used by management in its analysis of segment performance and management of our business. We believe Adjusted Segment EBDA is a useful performance metric because it provides management and external users of our financial statements additional insight into the ability of our segments to generate cash earnings on an ongoing basis. We believe it is useful to investors because it is a measure that management uses to allocate resources to our segments and assess each segment's performance. We believe the GAAP measure most directly comparable to Adjusted Segment EBDA is Segment EBDA. See *"—Consolidated Earnings Results (GAAP)—Certain Items Affecting Consolidated Earnings Results"* for a reconciliation of Segment EBDA to Adjusted Segment EBDA by business segment.

Adjusted EBITDA

Adjusted EBITDA is calculated by adjusting EBITDA for Certain Items. We also include amounts from joint ventures for income taxes and DD&A (see "Amounts from Joint Ventures" below). Adjusted EBITDA is used by management and external users, in conjunction with our Net Debt (as described further below), to evaluate certain leverage metrics. Therefore, we believe Adjusted EBITDA is useful to investors. We believe the GAAP measure most directly comparable to Adjusted EBITDA is net income. See *"—Adjusted Segment EBDA to Adjusted EBITDA to DCF"* and *"—Non-GAAP Financial Measures—Reconciliation of Net Income (GAAP) to Adjusted EBITDA"* below.

Amounts from Joint Ventures

Certain Items, DCF and Adjusted EBITDA reflect amounts from unconsolidated joint ventures and consolidated joint ventures utilizing the same recognition and measurement methods used to record "Earnings from equity investments" and "Noncontrolling interests," respectively. The calculations of DCF and Adjusted EBITDA related to our unconsolidated and consolidated joint ventures include the same adjustments (DD&A and income tax expense, and for DCF only, also cash taxes and sustaining capital expenditures) with respect to the joint ventures as those included in the calculations of DCF and Adjusted EBITDA for our wholly-owned consolidated subsidiaries. (See *"—Non-GAAP Financial Measures—Supplemental Information"* below.) Although these amounts related to our unconsolidated joint ventures are included in the calculations of DCF and Adjusted EBITDA, such inclusion should not be understood to imply that we have control over the operations and resulting revenues, expenses or cash flows of such unconsolidated joint ventures. DCF and Adjusted EBITDA are further adjusted for certain KML activities attributable to our noncontrolling interests in KML for the periods presented through KML's sale on December 16, 2019, see *"—Non-GAAP Financial Measures—Supplemental Information—KML Activities Prior to December 16, 2019"* below.

Net Debt

Net Debt is calculated, based on amounts as of December 31, 2020, by subtracting the following amounts from our debt balance of $34,689 million: (i) cash and cash equivalents of $1,184 million; (ii) debt fair value adjustments of $1,293 million; and (iii) the foreign exchange impact on Euro-denominated bonds of $170 million for which we have entered into currency swaps. Net Debt is a non-GAAP financial measure that is useful to investors and other users of our financial information in evaluating our leverage. We believe the most comparable measure to Net Debt is debt net of cash and cash equivalents. Our Net Debt-to-Adjusted EBITDA ratio was 4.6 as of December 31, 2020.

Consolidated Earnings Results (GAAP)

The following tables summarize the key components of our consolidated earnings results.

	Year Ended December 31,			
	2020	2019	Earnings increase/(decrease)	
	(In millions, except percentages)			
Segment EBDA(a)				
Natural Gas Pipelines	$ 3,483	$ 4,661	$ (1,178)	(25)%
Products Pipelines	977	1,225	(248)	(20)%
Terminals	1,045	1,506	(461)	(31)%
CO_2	(292)	681	(973)	(143)%
Kinder Morgan Canada	—	(2)	2	100 %
Total segment EBDA	5,213	8,071	(2,858)	(35)%
DD&A	(2,164)	(2,411)	247	10 %
Amortization of excess cost of equity investments	(140)	(83)	(57)	(69)%
General and administrative and corporate charges	(653)	(611)	(42)	(7)%
Interest, net	(1,595)	(1,801)	206	11 %
Income before income taxes	661	3,165	(2,504)	(79)%
Income tax expense	(481)	(926)	445	48 %
Net income	180	2,239	(2,059)	(92)%
Net income attributable to noncontrolling interests	(61)	(49)	(12)	(24)%
Net income attributable to Kinder Morgan, Inc.	$ 119	$ 2,190	$ (2,071)	(95)%

(a) Includes revenues, earnings from equity investments, and other, net, less operating expenses, loss (gain) on impairments and divestitures, net, and other income, net. Operating expenses include costs of sales, operations and maintenance expenses, and taxes, other than income taxes.

Year Ended December 31, 2020 vs. 2019

Net income attributable to Kinder Morgan, Inc. decreased $2,071 million in 2020 compared to 2019. The decrease was due primarily to $1,950 million of non-cash impairments of goodwill associated with our Natural Gas Pipelines Non-Regulated and CO_2 reporting units and non-cash impairments of certain oil and gas producing assets in our CO_2 business segment. The decrease in results was further impacted by lower earnings from all of our business segments primarily attributable to COVID-19-related reduced energy demand and commodity price impacts and the impact of the KML and U.S. Cochin Sale in the fourth quarter of 2019 on our Natural Gas Pipelines and Terminals business segments, partially offset by the benefit of completed expansion projects in our Natural Gas Pipelines business segment, by lower interest expense and DD&A expense, and by lower income tax expense due to 2019 income taxes related to the KML and U.S. Cochin Sale.

Certain Items Affecting Consolidated Earnings Results

	Year Ended December 31,						
	2020			2019			
	GAAP	**Certain Items**	**Adjusted**	**GAAP**	**Certain Items**	**Adjusted**	**Adjusted amounts increase/ (decrease) to earnings**
				(In millions)			
Segment EBDA							
Natural Gas Pipelines	$ 3,483	$ 983	$ 4,466	$ 4,661	$ (51)	$ 4,610	$ (144)
Products Pipelines	977	50	1,027	1,225	33	1,258	(231)
Terminals	1,045	(55)	990	1,506	(332)	1,174	(184)
CO_2	(292)	944	652	681	26	707	(55)
Kinder Morgan Canada	—	—	—	(2)	2	—	—
Total Segment EBDA(a)	5,213	1,922	7,135	8,071	(322)	7,749	(614)
DD&A and amortization of excess cost of equity investments	(2,304)	—	(2,304)	(2,494)	—	(2,494)	190
General and administrative and corporate charges(a)	(653)	92	(561)	(611)	13	(598)	37
Interest, net(a)	(1,595)	(15)	(1,610)	(1,801)	(15)	(1,816)	206
Income before income taxes	661	1,999	2,660	3,165	(324)	2,841	(181)
Income tax expense(b)	(481)	(107)	(588)	(926)	299	(627)	39
Net income	180	1,892	2,072	2,239	(25)	2,214	(142)
Net income attributable to noncontrolling interests(a)	(61)	—	(61)	(49)	(4)	(53)	(8)
Net income attributable to Kinder Morgan, Inc.	$ 119	$ 1,892	$ 2,011	$ 2,190	$ (29)	$ 2,161	$ (150)

(a) For a more detailed discussion of these Certain Items, see the footnotes to the tables within *"—Segment Earnings Results" and "—DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests"* below.

(b) The combined net effect of the Certain Items represents the income tax provision on Certain Items plus discrete income tax items.

Net income attributable to Kinder Morgan, Inc. adjusted for Certain Items (Adjusted Earnings) decreased by $150 million from the prior year and was primarily due to lower earnings from all of our business segments primarily attributable to COVID-19-related reduced energy demand and commodity price impacts and the impact of the KML and U.S. Cochin Sale in the fourth quarter of 2019 on our Natural Gas Pipelines and Terminals business segments, partially offset by the benefit of completed expansion projects in our Natural Gas Pipelines business segment and by lower interest expense and DD&A expense.

Non-GAAP Financial Measures

Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF

	Year Ended December 31, 2020	2019
	(In millions)	
Net income attributable to Kinder Morgan Inc. (GAAP)	$ 119	$ 2,190
Total Certain Items	1,892	(29)
Adjusted Earnings(a)	2,011	2,161
DD&A and amortization of excess cost of equity investments for DCF(b)	2,671	2,867
Income tax expense for DCF(a)(b)	670	714
Cash taxes(c)	(68)	(90)
Sustaining capital expenditures(c)	(658)	(688)
Other items(d)	(29)	29
DCF	$ 4,597	$ 4,993

Adjusted Segment EBDA to Adjusted EBITDA to DCF

	Year Ended December 31, 2020	2019
	(In millions, except per share amounts)	
Natural Gas Pipelines	$ 4,466	$ 4,610
Products Pipelines	1,027	1,258
Terminals	990	1,174
CO_2	652	707
Adjusted Segment EBDA(a)	7,135	7,749
General and administrative and corporate charges(a)	(561)	(598)
Joint venture DD&A and income tax expense(a)(e)	449	487
Net income attributable to noncontrolling interests (net of KML noncontrolling interests and Certain Items)(a)	(61)	(20)
Adjusted EBITDA	6,962	7,618
Interest, net(a)	(1,610)	(1,816)
Cash taxes(c)	(68)	(90)
Sustaining capital expenditures(c)	(658)	(688)
KML noncontrolling interests DCF adjustments(f)	—	(60)
Other items(d)	(29)	29
DCF	$ 4,597	$ 4,993
Adjusted Earnings per common share	$ 0.88	$ 0.95
Weighted average common shares outstanding for dividends(g)	2,276	2,276
DCF per common share	$ 2.02	$ 2.19
Declared dividends per common share	$ 1.05	$ 1.00

(a) Amounts are adjusted for Certain Items. See tables included in *"—Reconciliation of Net Income (GAAP) to Adjusted EBITDA"* and *"—Supplemental Information"* below.

(b) Includes DD&A or income tax expense, as applicable, from joint ventures. 2019 amounts are also net of DD&A or income tax expense attributable to KML noncontrolling interests. See tables included in *"—Supplemental Information"* below.

(c) Includes cash taxes or sustaining capital expenditures, as applicable, from joint ventures. See tables included in *"—Supplemental Information"* below.

(d) Includes pension contributions and non-cash pension expense, and non-cash compensation associated with our restricted stock program.

(e) Represents joint venture DD&A and income tax expense. See tables included in *"—Supplemental Information"* below.
(f) 2019 amount represents the combined net income, DD&A and income tax expense adjusted for Certain Items, as applicable, attributable to KML noncontrolling interests. See table included in *"—Supplemental Information"* below.
(g) Includes restricted stock awards that participate in common share dividends.

Reconciliation of Net Income (GAAP) to Adjusted EBITDA

	Year Ended December 31,	
	2020	**2019**
	(In millions)	
Net income (GAAP)	$ 180	$ 2,239
Certain Items:		
Fair value amortization	(21)	(29)
Legal, environmental and taxes other than income tax reserves	26	46
Change in fair value of derivative contracts(a)	(5)	(24)
Loss (gain) on impairments and divestitures, net(b)	327	(280)
Loss on impairment of goodwill(c)	1,600	—
Restricted stock accelerated vesting and severance	52	—
COVID-19 costs	15	—
Income tax Certain Items	(107)	299
Noncontrolling interests associated with Certain Items	—	(4)
Other	5	(37)
Total Certain Items(d)	1,892	(29)
DD&A and amortization of excess cost of equity investments	2,304	2,494
Income tax expense(e)	588	627
Joint venture DD&A and income tax expense(e)(f)	449	487
Interest, net(e)	1,610	1,816
Net income attributable to noncontrolling interests (net of KML noncontrolling interests(e))	(61)	(16)
Adjusted EBITDA	$ 6,962	$ 7,618

(a) Gains or losses are reflected in our DCF when realized.
(b) 2020 amount includes: (i) a pre-tax non-cash impairment loss of $350 million related to oil and gas producing assets in our CO_2 business segment driven by low oil prices and (ii) $21 million for asset impairments in our Products Pipelines business segment, which are reported within "Loss (gain) on impairments and divestitures, net" on the accompanying consolidated statement of income. 2019 amount primarily includes: (i) a $1,296 million pre-tax gain on the KML and U.S. Cochin Sale and a pre-tax loss of $364 million for asset impairments, related to gathering and processing assets in Oklahoma and northern Texas in our Natural Gas Pipelines business segment and oil and gas producing assets in our CO_2 business segment, which are reported within "Loss (gain) on impairments and divestitures, net" on the accompanying consolidated statement of income and (ii) a pre-tax $650 million loss for an impairment of our investment in Ruby Pipeline which is reported within "Earnings from equity investments" on the accompanying consolidated statement of income.
(c) 2020 amount includes non-cash impairments of goodwill of $1,000 million and $600 million associated with our Natural Gas Pipelines Non-Regulated and our CO_2 reporting units, respectively.
(d) 2020 and 2019 amounts include $(4) million and $634 million, respectively, reported within "Earnings from equity investments" on our accompanying consolidated statements of income.
(e) Amounts are adjusted for Certain Items. See tables included in *"—Supplemental Information"* and *"—DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests"* below.
(f) Represents joint venture DD&A and income tax expense. See table included in *"—Supplemental Information"* below.

Supplemental Information

	Year Ended December 31, 2020	2019
	(In millions)	
DD&A (GAAP)	$ 2,164	$ 2,411
Amortization of excess cost of equity investments (GAAP)	140	83
DD&A and amortization of excess cost of equity investments	2,304	2,494
Joint venture DD&A	367	392
DD&A attributable to KML noncontrolling interests	—	(19)
DD&A and amortization of excess cost of equity investments for DCF	$ 2,671	$ 2,867
Income tax expense (GAAP)	$ 481	$ 926
Certain Items	107	(299)
Income tax expense(a)	588	627
Unconsolidated joint venture income tax expense(a)(b)	82	95
Income tax expense attributable to KML noncontrolling interests(a)	—	(8)
Income tax expense for DCF(a)	$ 670	$ 714
KML activities prior to December 16, 2019		
Net income attributable to KML noncontrolling interests	$ —	$ 29
KML noncontrolling interests associated with Certain Items	—	4
KML noncontrolling interests(a)	—	33
DD&A attributable to KML noncontrolling interests	—	19
Income tax expense attributable to KML noncontrolling interests(a)	—	8
KML noncontrolling interests DCF adjustments(a)	$ —	$ 60
Net income attributable to noncontrolling interests (GAAP)	$ 61	$ 49
Less: KML noncontrolling interests(a)	—	33
Net income attributable to noncontrolling interests (net of KML noncontrolling interests(a))	61	16
Noncontrolling interests associated with Certain Items	—	4
Net income attributable to noncontrolling interests (net of KML noncontrolling interests and Certain Items)	$ 61	$ 20
Additional joint venture information		
Unconsolidated joint venture DD&A	$ 407	$ 411
Less: Consolidated joint venture partners' DD&A	40	19
Joint venture DD&A	367	392
Unconsolidated joint venture income tax expense(a)(b)	82	95
Joint venture DD&A and income tax expense(a)	$ 449	$ 487
Unconsolidated joint venture cash taxes(b)	$ (62)	$ (61)
Unconsolidated joint venture sustaining capital expenditures	$ (120)	$ (114)
Less: Consolidated joint venture partners' sustaining capital expenditures	(6)	(6)
Joint venture sustaining capital expenditures	$ (114)	$ (108)

(a) Amounts are adjusted for Certain Items.
(b) Amounts are associated with our Citrus, NGPL and PPL pipeline equity investments.

Segment Earnings Results

Natural Gas Pipelines

	Year Ended December 31,	
	2020	2019
	(In millions, except operating statistics)	
Revenues	$ 7,259	$ 8,170
Operating expenses	(3,457)	(4,213)
(Loss) gain on impairments and divestitures, net	(1,010)	677
Other income	1	3
Earnings (losses) from equity investments	679	(29)
Other, net	11	53
Segment EBDA	3,483	4,661
Certain Items(a)	983	(51)
Adjusted Segment EBDA	$ 4,466	$ 4,610

Change from prior period	Increase/ (Decrease)	
Adjusted Segment EBDA	$ (144)	
Volumetric data(b)		
Transport volumes (BBtu/d)	37,487	36,793
Sales volumes (BBtu/d)	2,353	2,420
Gathering volumes (BBtu/d)	3,039	3,382
NGLs (MBbl/d)	27	32

Certain Items affecting Segment EBDA

(a) Includes Certain Item amounts of $983 million and $(51) million for 2020 and 2019, respectively. 2020 amount includes (i) a $1,000 million non-cash goodwill impairment on our Natural Gas Pipelines Non-Regulated reporting unit; (ii) an increase in revenues of $19 million resulting from amortization of regulatory liabilities including amounts recognized through earnings from equity investments; and (iii) a decrease in revenues of $15 million related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas and NGL sales. 2019 amount includes (i) a $957 million gain on the sale of Cochin Pipeline system; (ii) a $650 million non-cash impairment loss related to our investment in Ruby; (iii) $157 million and $133 million non-cash losses on impairments of certain gathering and processing assets in North Texas and Oklahoma, respectively; (iv) an increase in earnings of $23 million for a gain on an ownership rights contract with a joint venture partner; (v) a $16 million increase in earnings related to amortization of regulatory liabilities recognized through earnings of equity investments; and (vi) a $12 million decrease in revenues related to non-cash mark-to-market derivative contracts used to hedge forecasted natural gas and NGL sales.

Other

(b) Joint venture throughput is reported at our ownership share. Volumes for assets sold are excluded for all periods presented.

Below are the changes in Adjusted Segment EBDA between 2020 and 2019:

Year Ended December 31, 2020 versus Year Ended December 31, 2019

	Adjusted Segment EBDA increase/(decrease)	
	(In millions, except percentages)	
Midstream	$ (254)	(18)%
West Region	(47)	(4)%
East Region	157	7%
Total Natural Gas Pipelines	$ (144)	(3)%

The changes in Segment EBDA for our Natural Gas Pipelines business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2020 and 2019:

- Midstream's decrease of $254 million (18%) was primarily due to (i) a decrease of $142 million related to the sale of the Cochin Pipeline system on December 16, 2019 to Pembina; (ii) lower commodity prices on, a decrease in volumes and two customer bankruptcies associated with our South Texas assets; (iii) lower volumes on KinderHawk; and (iv) lower contract rates on our North Texas assets. These decreases were partially offset by higher equity earnings due to the Gulf Coast Express Pipeline being placed in service in September 2019. Overall Midstream's revenues decreased primarily due to lower commodity prices which was largely offset by corresponding decreases in costs of sales;
- West Region's decrease of $47 million (4%) was primarily due to decreases in earnings from (i) Ruby Pipeline Company, L.L.C. due principally to credit losses and lost revenues resulting from two of its customers' bankruptcies; (ii) CPGPL as a result of the expiration of one shipper's contract; and (iii) EPNG driven by higher operating expenses; and
- East Region's increase of $157 million (7%) was primarily due to increases in earnings from ELC and SLNG resulting from the liquefaction units of the Elba Liquefaction project gradually being placed into service in the later part of 2019 and through the first eight months of 2020, and increased equity earnings from NGPL primarily due to higher revenues. These increases were partially offset by reduced contributions from TGP due to the impact of the FERC 501-G rate settlement on its revenues.

Products Pipelines

	Year Ended December 31, 2020	Year Ended December 31, 2019
	(In millions, except operating statistics)	
Revenues	$ 1,721	$ 1,831
Operating expenses	(779)	(684)
Loss on impairments and divestitures, net	(21)	—
Earnings from equity investments	55	72
Other, net	1	6
Segment EBDA	977	1,225
Certain Items(a)	50	33
Adjusted Segment EBDA	$ 1,027	$ 1,258

Change from prior period	Increase/ (Decrease)
Adjusted Segment EBDA	$ (231)

Volumetric data(b)	2020	2019
Gasoline(c)	897	1,041
Diesel fuel	375	368
Jet fuel	179	306
Total refined product volumes	1,451	1,715
Crude and condensate	552	651
Total delivery volumes (MBbl/d)	2,003	2,366

Certain Items affecting Segment EBDA

(a) Includes Certain Item amounts of $50 million and $33 million in the 2020 and 2019 periods, respectively. 2020 amount includes a $46 million unfavorable rate case reserve adjustment, a non-cash loss on impairment of our Belton Terminal of $21 million and a $17 million favorable adjustment for tax reserves, other than income taxes. 2019 amount primarily related to unfavorable adjustments of an environmental reserve and of tax reserves, other than income taxes.

Other

(b) Joint venture throughput is reported at our ownership share.

(c) Volumes include ethanol pipeline volumes.

Below are the changes in Adjusted Segment EBDA between 2020 and 2019:

Year Ended December 31, 2020 versus Year Ended December 31, 2019

	Adjusted Segment EBDA increase/(decrease)	
	(In millions, except percentages)	
Crude and Condensate	$ (119)	(25)%
West Coast Refined Products	(63)	(12)%
Southeast Refined Products	(49)	(18)%
Total Products Pipelines	$ (231)	(18)%

The changes in Segment EBDA for our Products Pipelines business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2020 and 2019:

- Crude and Condensate's decrease of $119 million (25%) was primarily due to decreased earnings from Kinder Morgan Crude & Condensate Pipeline (KMCC) and the Bakken Crude assets. KMCC's decreased earnings were primarily due to lower volumes. The Bakken Crude assets decreased earnings were primarily driven by lower volumes and reduced re-contracted rates on Double H pipeline. KMCC and Bakken Crude assets decreases were also impacted by unfavorable inventory valuation adjustments driven by declines in commodity prices during the first quarter 2020;

- West Coast Refined Products' decrease of $63 million (12%) was due to decreased earnings on Pacific (SFPP) operations, Calnev Pipe Line LLC and West Coast terminals driven by lower service revenues as a result of a reduction in volumes due to COVID-19; and
- Southeast Refined Products' decrease of $49 million (18%) was primarily due to decreased earnings from our South East Terminals and a decrease in equity earnings from PPL pipeline as a result of decreased services revenues driven by lower volumes and prices due to COVID-19, and lower earnings from our Transmix processing operations driven by unfavorable inventory adjustments resulting from commodity price declines during the first quarter 2020.

Terminals

	Year Ended December 31,	
	2020	**2019**
	(In millions, except operating statistics)	
Revenues	$ 1,722	$ 2,034
Operating expenses	(762)	(888)
Gain on divestitures and impairments, net	49	342
Other income	1	—
Earnings from equity investments	22	23
Other, net	13	(5)
Segment EBDA	1,045	1,506
Certain Items(a)	(55)	(332)
Adjusted Segment EBDA	$ 990	$ 1,174

Change from prior period	**Increase/ (Decrease)**	
Adjusted Segment EBDA	$ (184)	
Volumetric data(b)		
Liquids leasable capacity (MMBbl)	79.7	79.7
Liquids utilization %(c)	95.3 %	93.2 %
Bulk transload tonnage (MMtons)	48.0	55.3

Certain Items affecting Segment EBDA

(a) Includes Certain Item amounts of $(55) million and $(332) million for 2020 and 2019, respectively. 2020 amount related to a gain on sale of our Staten Island terminal and 2019 amount primarily related to a gain of $339 million on the sale of KML.

Other

(b) Volumes for assets sold are excluded for all periods presented.

(c) The ratio of our tankage capacity in service to tankage capacity available for service.

Below are the changes in Adjusted Segment EBDA between 2020 and 2019:

Year Ended December 31, 2020 versus Year Ended December 31, 2019

	Adjusted Segment EBDA increase/(decrease)		
	(In millions, except percentages)		
Alberta Canada	$	(124)	(100)%
Gulf Liquids		(23)	(7)%
West Coast		(22)	(100)%
Mid Atlantic		(10)	(15)%
Gulf Bulk		(8)	(12)%
All others (including intrasegment eliminations)		3	1%
Total Terminals	$	(184)	(16)%

The changes in Segment EBDA for our Terminals business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2020 and 2019:

- the Sale of KML assets to Pembina on December 16, 2019, which accounted for the decreases on our Alberta Canada terminals and our West Coast terminals;
- decrease of $23 million (7%) from our Gulf Liquids terminals primarily driven by lower volumes and associated ancillary fees related to demand reduction attributable to COVID-19 as well as tanks being temporarily off-lease as they are transitioned to new customers following the termination of a major customer contract;
- decrease of $10 million (15%) from our Mid Atlantic terminals primarily due to lower coal volumes at our Pier IX facility driven by coal market weakness largely attributable to demand reduction associated with COVID-19; and
- decrease of $8 million (12%) from our Gulf Bulk terminals primarily due to decreased coal volumes and the impact of an expired contract in January 2020.

CO_2

	Year Ended December 31,	
	2020	2019
	(In millions, except operating statistics)	
Revenues	$ 1,038	$ 1,219
Operating expenses	(404)	(496)
Loss on impairments and divestitures, net	(950)	(76)
Other expense	—	(1)
Earnings from equity investments	24	35
Segment EBDA	(292)	681
Certain Items(a)	944	26
Adjusted Segment EBDA	$ 652	$ 707

Change from prior period	Increase/ (Decrease)
Adjusted Segment EBDA	$ (55)

Volumetric data		
SACROC oil production	21.8	23.9
Yates oil production	6.6	7.2
Katz and Goldsmith oil production	2.8	3.8
Tall Cotton oil production	1.7	2.3
Total oil production, net (MBbl/d)(b)	32.9	37.2
NGL sales volumes, net (MBbl/d)(b)	9.5	10.1
CO_2 sales volumes, net (Bcf/d)	0.4	0.6
Realized weighted average oil price ($ per Bbl)	$ 53.78	$ 49.49
Realized weighted average NGL price ($ per Bbl)	$ 17.95	$ 23.49

Certain Items affecting Segment EBDA

(a) Includes Certain Item amounts of $944 million and $26 million for 2020 and 2019, respectively. 2020 amount includes (i) a $600 million goodwill impairment on our CO_2 reporting unit and (ii) non-cash impairments of $350 million on our oil and gas producing assets. 2019 amount includes non-cash impairments of $75 million on our oil and gas producing assets and an increase in revenues of $49 million related to mark-to-market gains associated with derivative contracts used to hedge forecasted commodity sales.

Other

(b) Net of royalties and outside working interests.

Below are the changes in Adjusted Segment EBDA between 2020 and 2019:

Year Ended December 31, 2020 versus Year Ended December 31, 2019

	Adjusted Segment EBDA increase/(decrease)	
	(In millions, except percentages)	
Source and Transportation activities	$ (82)	(28)%
Oil and Gas Producing activities	27	6%
Total CO_2	$ (55)	(8)%

The changes in Segment EBDA for our CO_2 business segment are further explained by the following discussion of the significant factors driving Adjusted Segment EBDA in the comparable years of 2020 and 2019:

- decrease of $82 million (28%) from our Source and Transportation activities primarily due to a decrease of $103 million related to lower CO_2 sales volumes partially offset by lower operating expenses of $28 million; and
- increase of $27 million (6%) from our Oil and Gas Producing activities primarily due to (i) lower operating expenses of $69 million; and (ii) higher realized crude oil prices which increased revenues by $62 million, offset by (i) lower volumes which decreased revenues by $92 million; and (ii) lower NGL prices which decreased revenues by $24 million.

We believe that our existing hedge contracts in place within our CO_2 business segment substantially mitigate commodity price sensitivities in the near-term and to lesser extent over the following few years from price exposure. Below is a summary of our CO_2 business segment hedges outstanding as of December 31, 2020.

	2021	2022	2023	2024
Crude Oil(a)				
Price ($ per Bbl)	$ 50.37	$ 50.98	$ 49.78	$ 43.50
Volume (MBbl/d)	25.70	10.80	5.45	1.55
NGLs				
Price ($ per Bbl)	$ 29.26			
Volume (MBbl/d)	4.24			
Midland-to-Cushing Basis Spread				
Price ($ per Bbl)	$ 0.26			
Volume (MBbl/d)	24.55			

(a) Includes West Texas Intermediate hedges.

DD&A, General and Administrative and Corporate Charges, Interest, net and Noncontrolling Interests

	Year Ended December 31,	
	2020	2019
	(In millions)	
DD&A (GAAP)	$ (2,164)	$ (2,411)
General and administrative (GAAP)	$ (648)	$ (590)
Corporate charges	(5)	(21)
Certain Items(a)	92	13
General and administrative and corporate charges(b)	$ (561)	$ (598)
Interest, net (GAAP)	$ (1,595)	$ (1,801)
Certain Items(c)	(15)	(15)
Interest, net(b)	$ (1,610)	$ (1,816)
Net income attributable to noncontrolling interests (GAAP)	$ (61)	$ (49)
Certain Items	—	(4)
Net income attributable to noncontrolling interests(b)	$ (61)	$ (53)

Certain Items

(a) 2020 amount includes $52 million for restricted stock accelerated vesting and severance expense, $15 million related to costs incurred associated with COVID-19 mitigation and an increase in expense of $23 million associated with a non-cash fair value adjustment and the dividend on the Pembina common stock. 2019 amount includes: (i) an increase in asset sale related costs of $15 million; (ii) an increase in expense of $13 million related to a litigation matter; and (iii) a decrease in expense of $19 million associated with a non-cash fair value adjustment on the Pembina common stock.

(b) Amounts are adjusted for Certain Items.
(c) 2020 and 2019 amounts include: (i) decreases in interest expense of $21 million and $29 million, respectively, related to non-cash debt fair value adjustments associated with acquisitions and (ii) increases of $8 million and $13 million, respectively, in interest expense related to non-cash mismatches between the change in fair value of interest rate swaps and change in fair value of hedged debt.

DD&A expense decreased $247 million in 2020 when compared to 2019 primarily due to larger non-cash impairments taken in the first quarter 2020 compared to the fourth quarter 2019 on our oil and gas producing assets, lower CO_2 business segment oil and gas production and the sale of KML partially offset by our Elba Liquefaction project gradually placed into service during 2019 and 2020.

General and administrative expenses and corporate charges adjusted for Certain Items decreased $37 million in 2020 when compared to 2019 primarily due to lower non-cash pension expenses of $45 million, lower expenses of $31 million due to the KML and U.S. Cochin Sale and $20 million of cost savings associated with efficiency efforts and reduced activity during the pandemic, partially offset by lower capitalized costs of $57 million reflecting reduced capital projects primarily in our Natural Gas Pipelines, CO_2 and Products Pipelines business segments.

In the table above, we report our interest expense as "net," meaning that we have subtracted interest income and capitalized interest from our total interest expense to arrive at one interest amount. Our consolidated interest expense, net adjusted for Certain Items decreased $206 million in 2020 when compared to 2019 primarily due to lower weighted average long-term debt balances and lower LIBOR rates partially offset by lower capitalized interest.

We use interest rate swap agreements to convert a portion of the underlying cash flows related to our long-term fixed rate debt securities (senior notes) into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. As of December 31, 2020 and 2019, approximately 16% and 27%, respectively, of the principal amount of our debt balances were subject to variable interest rates—either as short-term or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. For more information on our interest rate swaps, see Note 14 "*Risk Management—Interest Rate Risk Management*" to our consolidated financial statements.

Net income attributable to noncontrolling interests, represents the allocation of our consolidated net income attributable to all outstanding ownership interests in our consolidated subsidiaries that are not owned by us. Net income attributable to noncontrolling interests adjusted for Certain Items increased $8 million in 2020 compared to 2019.

Income Taxes

Year Ended December 31, 2020 versus Year Ended December 31, 2019

Our income tax expense for the year ended December 31, 2020 is approximately $481 million, as compared with income tax expense of $926 million for the same period of 2019. The $445 million decrease in income tax expense in 2020 as compared to 2019 is due primarily to (i) lower pretax income in 2020, (ii) lower foreign income taxes as a result of the KML and U.S. Cochin Sale in 2019, and (iii) the refund of alternative minimum tax sequestration credits in 2020. These decreases are partially offset by the lack of tax benefit on the higher impairment of non-tax deductible goodwill in 2020 and lower dividend-received deductions related to our investment in NGPL in 2020.

Liquidity and Capital Resources

General

As of December 31, 2020, we had $1,184 million of "Cash and cash equivalents," an increase of $999 million from December 31, 2019. Additionally, as of December 31, 2020, we had borrowing capacity of approximately $3.9 billion under our $4 billion revolving credit facility (discussed below in "*—Short-term Liquidity*"). As discussed further below, we believe our cash flows from operating activities, cash position and remaining borrowing capacity on our credit facility are more than adequate to allow us to manage our day-to-day cash requirements and anticipated obligations.

We have consistently generated substantial cash flow from operations, providing a source of funds of $4,550 million and $4,748 million in 2020 and 2019, respectively. The year-to-year decrease is discussed below in "*—Cash Flows—Operating Activities.*" We primarily rely on cash provided from operations to fund our operations as well as our debt service, sustaining capital expenditures, dividend payments, and our growth capital expenditures. We believe our current cash on hand, our cash from operations and our borrowing capacity under our revolving credit facility are more than adequate to allow us to manage our cash requirements, including maturing debt, through 2021; however, we may access the debt capital markets from time to time to refinance our maturing long-term debt.

Our board of directors declared a quarterly dividend of $0.2625 per share for the fourth quarter of 2020, consistent with previous quarters in 2020. The total of the dividends declared for 2020 of $1.05 represents a 5% increase over total dividends declared for 2019. We expect to fully fund our dividend payments as well as our discretionary spending for 2021 without funding from the capital markets with additional flexibility to engage in share repurchases on an opportunistic basis.

Short-term Liquidity

As of December 31, 2020, our principal sources of short-term liquidity are (i) cash from operations; (ii) our $4.0 billion revolving credit facility and associated commercial paper program; and (iii) cash and cash equivalents. The loan commitments under our revolving credit facility can be used for working capital and other general corporate purposes, and as a backup to our commercial paper program. Letters of credit and commercial paper borrowings reduce borrowings allowed under our credit facility. We provide for liquidity by maintaining a sizable amount of excess borrowing capacity under our credit facility and, as previously discussed, have consistently generated strong cash flows from operations. We do not anticipate any significant limitations from the continuing impacts of COVID-19 with respect to our ability to access funding through our credit facility.

As of December 31, 2020, our $2,558 million of short-term debt consisted primarily of senior notes that mature in the next twelve months. We intend to fund our debt, as it becomes due, primarily through credit facility borrowings, commercial paper borrowings, cash flows from operations, and/or issuing new long-term debt. Our short-term debt balance as of December 31, 2019 was $2,477 million.

We had working capital (defined as current assets less current liabilities) deficits of $1,871 million and $1,862 million as of December 31, 2020 and 2019, respectively. From time to time, our current liabilities may include short-term borrowings used to finance our expansion capital expenditures, which we may periodically replace with long-term financing and/or pay down using retained cash from operations. The overall slight $9 million unfavorable change from year-end 2019 was primarily due to: (i) a decrease of $925 million related to the sale of Pembina common equity in January 2020; (ii) an increase of approximately $216 million in senior notes that mature in the next twelve months; and (iii) the $100 million repayment of the preferred interest in Kinder Morgan G.P. Inc.; substantially offset by (i) an increase in cash and cash equivalents of $999 million; and (ii) a favorable asset fair value adjustment of $101 million on derivative contracts in 2020. Generally, our working capital balance varies due to factors such as the timing of scheduled debt payments, timing differences in the collection and payment of receivables and payables, the change in fair value of our derivative contracts, and changes in our cash and cash equivalent balances as a result of excess cash from operations after payments for investing and financing activities (discussed below in "*—Long-term Financing*" and "*—Capital Expenditures*").

We employ a centralized cash management program for our U.S.-based bank accounts that concentrates the cash assets of our wholly owned subsidiaries in joint accounts for the purpose of providing financial flexibility and lowering the cost of borrowing. These programs provide that funds in excess of the daily needs of our wholly owned subsidiaries are concentrated, consolidated or otherwise made available for use by other entities within the consolidated group. We place no material restrictions on the ability to move cash between entities, payment of intercompany balances or the ability to upstream dividends to KMI other than restrictions that may be contained in agreements governing the indebtedness of those entities.

Certain of our wholly owned subsidiaries are subject to FERC-enacted reporting requirements for oil and natural gas pipeline companies that participate in cash management programs. FERC-regulated entities subject to these rules must, among other things, place their cash management agreements in writing, maintain current copies of the documents authorizing and supporting their cash management agreements, and file documentation establishing the cash management program with the FERC.

Credit Ratings and Capital Market Liquidity

We believe that our capital structure will continue to allow us to achieve our business objectives. We expect that our short-term liquidity needs will be met primarily through retained cash from operations or short-term borrowings. Generally, we anticipate re-financing maturing long-term debt obligations in the debt capital markets and are therefore subject to certain market conditions which could result in higher costs or negatively affect our and/or our subsidiaries' credit ratings. A decrease in our credit ratings could negatively impact our borrowing costs and could limit our access to capital, including our ability to refinance maturities of existing indebtedness on similar terms, which could in turn reduce our cash flows and limit our ability to pursue acquisition or expansion opportunities.

As of December 31, 2020, our short-term corporate debt ratings were A-2, Prime-2 and F2 at Standard and Poor's, Moody's Investor Services and Fitch Ratings, Inc., respectively.

The following table represents KMI's and KMP's senior unsecured debt ratings as of December 31, 2020.

Rating agency	Senior debt rating	Outlook
Standard and Poor's	BBB	Stable
Moody's Investor Services	Baa2	Stable
Fitch Ratings, Inc.	BBB	Stable

Long-term Financing

Our equity consists of Class P common stock with a par value of $0.01 per share. We do not expect to need to access the equity capital markets to fund our discretionary capital investments for the foreseeable future. See also "—*Dividends and Stock Buy-back Program*" below for additional discussion related to our dividends and stock buy-back program.

From time to time, we issue long-term debt securities, often referred to as senior notes. All of our senior notes issued to date, other than those issued by certain of our subsidiaries, generally have very similar terms, except for interest rates, maturity dates and prepayment premiums. All of our fixed rate senior notes provide that the notes may be redeemed at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date, and, in most cases, plus a make-whole premium. In addition, from time to time, our subsidiaries issue long-term debt securities. Furthermore, we and almost all of our direct and indirect wholly owned domestic subsidiaries are parties to a cross guaranty wherein we each guarantee each other's debt. See "—*Summarized Combined Financial Information for Guarantee of Securities of Subsidiaries*. As of December 31, 2020 and 2019, the aggregate principal amount outstanding of our various long-term debt obligations (excluding current maturities) was $30,838 million and $30,883 million, respectively.

On August 5, 2020, we issued in a registered offering two series of senior notes consisting of $750 million aggregate principal amount of 2.00% senior notes due 2031 and $500 million aggregate principal amount of 3.25% senior notes due 2050 and received combined net proceeds of $1,226 million. We used the proceeds to repay maturing debt, including in early January 2021, our $750 million 3.50% senior notes that were scheduled to mature in March 2021.

To refinance construction costs of its recent expansions, on February 24, 2020, TGP, a wholly owned subsidiary, issued in a private placement $1,000 million aggregate principal amount of its 2.90% senior notes due 2030 and received net proceeds of $991 million.

We achieve our variable rate exposure primarily by issuing long-term fixed rate debt and then swapping the fixed rate interest payments for variable rate interest payments and through the issuance of commercial paper or credit facility borrowings.

For additional information about our outstanding senior notes and debt-related transactions in 2020 , see Note 9 *"Debt"* to our consolidated financial statements. For information about our interest rate risk, see Item 7A "*Quantitative and Qualitative Disclosures About Market Risk—Interest Rate Risk.*"

Counterparty Creditworthiness

Some of our customers or other counterparties may experience severe financial problems that may have a significant impact on their creditworthiness. These financial problems may arise from our current global economic conditions, continued volatility of commodity prices or otherwise. In such situations, we utilize, to the extent allowable under applicable contracts, tariffs and regulations, prepayments and other security requirements, such as letters of credit, to enhance our credit position relating to amounts owed from these counterparties. While we believe we have taken reasonable measures to protect against counterparty credit risk, we cannot provide assurance that one or more of our customers or other counterparties will not become financially distressed and will not default on their obligations to us. The balance of our allowance for credit losses as of December 31, 2020 and December 31, 2019, was $26 million and $9 million, respectively, reflected in "Other current assets" on our consolidated balance sheets, which includes reserves for counterparty bankruptcies recorded during the year ended December 31, 2020.

Capital Expenditures

We account for our capital expenditures in accordance with GAAP. We also distinguish between capital expenditures that are maintenance/sustaining capital expenditures and those that are expansion capital expenditures (which we also refer to as discretionary capital expenditures). Expansion capital expenditures are those expenditures which increase throughput or capacity from that which existed immediately prior to the addition or improvement, and are not deducted in calculating DCF (see "*—Results of Operations—Non-GAAP Financial Measures—Reconciliation of Net Income Attributable to Kinder Morgan, Inc. (GAAP) to Adjusted Earnings to DCF*"). With respect to our oil and gas producing activities, we classify a capital expenditure as an expansion capital expenditure if it is expected to increase capacity or throughput (i.e., production capacity) from the capacity or throughput immediately prior to the making or acquisition of such additions or improvements. Maintenance capital expenditures are those which maintain throughput or capacity. The distinction between maintenance and expansion capital expenditures is a physical determination rather than an economic one, irrespective of the amount by which the throughput or capacity is increased.

Budgeting of maintenance capital expenditures is done annually on a bottom-up basis. For each of our assets, we budget for and make those maintenance capital expenditures that are necessary to maintain safe and efficient operations, meet customer needs and comply with our operating policies and applicable law. We may budget for and make additional maintenance capital expenditures that we expect to produce economic benefits such as increasing efficiency and/or lowering future expenses. Budgeting and approval of expansion capital expenditures are generally made periodically throughout the year on a project-by-project basis in response to specific investment opportunities identified by our business segments from which we generally expect to receive sufficient returns to justify the expenditures. Generally, the determination of whether a capital expenditure is classified as maintenance/sustaining or as expansion capital expenditures is made on a project level. The classification of our capital expenditures as expansion capital expenditures or as maintenance capital expenditures is made consistent with our accounting policies and is generally a straightforward process, but in certain circumstances can be a matter of management judgment and discretion. The classification has an impact on DCF because capital expenditures that are classified as expansion capital expenditures are not deducted from DCF, while those classified as maintenance capital expenditures are.

Our capital expenditures for the year ended December 31, 2020, and the amount we expect to spend for 2021 to sustain our assets and grow our business are as follows:

	2020	Expected 2021
	(In millions)	
Sustaining capital expenditures(a)(b)	$ 658	$ 792
Discretionary capital investments(b)(c)(d)	1,692	794

(a) 2020 and Expected 2021 amounts include $114 million and $119 million, respectively, for sustaining capital expenditures from unconsolidated joint ventures, reduced by consolidated joint venture partners' sustaining capital expenditures. See table included in "*Non-GAAP Financial Measures—Supplemental Information*."

(b) 2020 excludes $21 million due to decreases in accrued capital expenditures and contractor retainage and net changes in other.

(c) 2020 amount includes $550 million of our contributions to certain unconsolidated joint ventures for capital investments and small acquisitions.

(d) Amounts include our actual or estimated contributions to certain unconsolidated joint ventures, net of actual or estimated contributions from certain partners in non-wholly owned consolidated subsidiaries for capital investments.

Off Balance Sheet Arrangements

We have invested in entities that are not consolidated in our financial statements. For information on our obligations with respect to these investments, as well as our obligations with respect to related letters of credit, see Note 13 *"Commitments and Contingent Liabilities"* to our consolidated financial statements. Additional information regarding the nature and business purpose of our investments is included in Note 7 *"Investments"* to our consolidated financial statements.

Contractual Obligations and Commercial Commitments

	Payments due by period				
	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(In millions)				
Contractual obligations:					
Debt borrowings-principal payments(a)	$ 33,396	$ 2,558	$ 5,825	$ 3,491	$ 21,522
Interest payments(b)	21,693	1,684	3,077	2,631	14,301
Lease obligations(c)	412	53	84	64	211
Pension and OPEB plans(d)	852	63	36	32	721
Transportation, volume and storage agreements(e)	631	163	223	143	102
Other obligations(f)	435	91	132	68	144
Total	$ 57,419	$ 4,612	$ 9,377	$ 6,429	$ 37,001
Other commercial commitments:					
Standby letters of credit(g)	$ 147	$ 74	$ 73	$ —	$ —
Capital expenditures(h)	$ 141	$ 141	$ —	$ —	$ —

(a) See Note 9 *"Debt"* to our consolidated financial statements.
(b) Interest payment obligations exclude adjustments for interest rate swap agreements and assume no change in variable interest rates from those in effect at December 31,2020.
(c) Represents commitments pursuant to the terms of operating lease agreements as of December 31, 2020.
(d) Represents the amount by which the benefit obligations exceeded the fair value of plan assets at year-end for pension and OPEB plans whose accumulated postretirement benefit obligations exceeded the fair value of plan assets. The payments by period include expected contributions in 2021 and estimated benefit payments for underfunded plans in the other years.
(e) Primarily represents transportation agreements of $279 million, NGL volume agreements of $208 million and storage agreements for capacity of $131 million.
(f) Primarily includes (i) rights-of-way obligations; and (ii) environmental liabilities related to sites that we own or have a contractual or legal obligation with a regulatory agency or property owner upon which we will perform remediation activities. These environmental liabilities are included within "Other current liabilities" and "Other long-term liabilities and deferred credits" in our consolidated balance sheet as of December 31, 2020.
(g) The $147 million in letters of credit outstanding as of December 31, 2020 consisted of the following (i) letters of credit totaling $46 million supporting our International Marine Terminals Partnership Plaquemines, Louisiana Port, Harbor, and Terminal Revenue Bonds; (ii) $46 million under seven letters of credit for insurance purposes; (iii) a $24 million letter of credit supporting our Kinder Morgan Operating LLC "B" tax-exempt bonds; and (iv) a combined $31 million in thirty letters of credit supporting environmental and other obligations of us and our subsidiaries.
(h) Represents commitments for the purchase of plant, property and equipment as of December 31, 2020.

Cash Flows

Operating Activities

Cash provided by operating activities decreased $198 million in 2020 compared to 2019 primarily due to:

- a $409 million decrease in cash after adjusting the $2,059 million decrease in net income by $1,650 million for the combined effects of the period-to-period net changes in non-cash items including the following: (i) loss on impairments and divestitures, net (see discussion above in "—Results of Operations"); (ii) changes in fair market value of derivative contracts; (iii) DD&A expenses (including amortization of excess cost of equity investments); (iv) deferred income taxes; and (v) earnings from equity investments; partially offset by
- a $145 million increase in cash primarily resulting from $227 million of net income tax payments in the 2020 period compared to $372 million of net income tax payments in the 2019 period, which in both periods were primarily for foreign income taxes associated with the sale of certain Canadian assets. The income tax payments for the 2020 period are net of a $20 million refund related to alternative minimum tax sequestration credits; and
- a $66 million increase in cash associated with net changes in working capital items, other than income tax payments, and other non-current assets and liabilities. The increase was driven, among other things, primarily by a favorable change due to the timing of trade payables payments, and partially offset by higher pension plan contributions we made in the 2020 period compared to the 2019 period.

Investing Activities

Cash used in investing activities decreased $803 million in 2020 compared to 2019 primarily due to:

◦ a $959 million increase in cash from the proceeds received from the sales of property, plant and equipment, investments, and other net assets, net of removal costs primarily due to $907 million of proceeds received from the sale of the Pembina shares in the 2020 period. See Note 4 *"Divestitures"* to our consolidated financial statements for further information regarding this transaction;
◦ a $913 million decrease in cash used for contributions to equity investments driven by lower contributions to Gulf Coast Express Pipeline LLC, MEP, Citrus, and FEP in the 2020 period compared with the 2019 period, partially offset by contributions made to SNG in the 2020 period; and
◦ a $563 million decrease in capital expenditures in the 2020 period over the comparative 2019 period primarily due to lower expenditures on the Elba Liquefaction expansion and also reflecting our reduction of expansion capital projects in the wake of COVID-19; partially offset by
◦ the $1,527 million decrease in cash resulting from proceeds received from the KML and U.S. Cochin Sale, net of cash disposed, in 2019. See Note 4 *"Divestitures"* to our consolidated financial statements for further information regarding this transaction; and
◦ a $179 million decrease in distributions received from equity investments in excess of cumulative earnings primarily from Ruby, FEP and SNG in the 2020 period over the comparative 2019 period.

Financing Activities

Cash used in financing activities decreased $3,547 million in 2020 compared to 2019 primarily due to:

- a $3,065 million net increase in cash from net debt activity primarily driven by an increase in long-term debt issuances, and to a lesser extent, lower long-term debt repayments and lower utilization of our credit facility for short-term borrowings, which resulted in a substantial decrease in each our total debt issuances and total debt payments, in the 2020 period compared to the 2019 period. See Note 9 "Debt" to our consolidated financial statements for further information regarding our debt activity; and
- an $879 million decrease in cash used resulting from the distribution of the TMPL sale proceeds to the owners of KML restricted voting shares in the 2019 period; partially offset by
- a $199 million increase in dividend payments to our common shareholders; and
- a $137 million decrease in contributions received from an investment partner and noncontrolling interests primarily driven by lower contributions received from EIG in the 2020 period compared to the 2019 period.

Dividends and Stock Buy-back Program

The table below reflects the declaration of common stock dividends of $1.05 per common share for 2020:

Three months ended	Total quarterly dividend per share for the period	Date of declaration	Date of record	Date of dividend
March 31, 2020	$0.2625	April 22, 2020	May 4, 2020	May 15, 2020
June 30, 2020	0.2625	July 22, 2020	August 3, 2020	August 17, 2020
September 30, 2020	0.2625	October 21, 2020	November 2, 2020	November 16, 2020
December 31, 2020	0.2625	January 20, 2021	February 1, 2021	February 16, 2021

We expect to continue to return additional value to our shareholders in 2021 through our previously announced dividend increase. We plan to increase our dividend by 3% to $1.08 per common share in 2021. Based on our 2021 expectations, we also expect to have the capacity to engage in opportunistic share repurchases up to $450 million during the year under our $2 billion common share buy-back program approved by our board of directors in July 2017. Since December 2017, in total, we have repurchased approximately 32 million of our Class P shares under the program at an average price of approximately $17.71 per share for approximately $575 million. For information on our equity buy-back program and our equity distribution agreement, see Note 11 *"Stockholders' Equity"* to our consolidated financial statements.

The actual amount of common stock dividends to be paid on our capital stock will depend on many factors, including our financial condition and results of operations, liquidity requirements, business prospects, capital requirements, legal, regulatory and contractual constraints, tax laws, Delaware laws and other factors. See Item 1A "*Risk Factors—The guidance we provide* *for our anticipated dividends is based on estimates. Circumstances may arise that lead to conflicts between using funds to pay anticipated dividends or to invest in our business."* All of these matters will be taken into consideration by our board of directors in declaring dividends.

Our common stock dividends are not cumulative. Consequently, if dividends on our common stock are not paid at the intended levels, our common stockholders are not entitled to receive those payments in the future. Our common stock dividends generally will be paid on or about the 15th day of each February, May, August and November.

Summarized Combined Financial Information for Guarantee of Securities of Subsidiaries

KMI and certain subsidiaries (Subsidiary Issuers) are issuers of certain debt securities. KMI and substantially all of KMI's wholly owned domestic subsidiaries (Subsidiary Guarantors), are parties to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement. Accordingly, with the exception of certain subsidiaries identified as Subsidiary Non-Guarantors, the parent issuer, subsidiary issuers and Subsidiary Guarantors (the "Obligated Group") are all guarantors of each series of our guaranteed debt (Guaranteed Notes). As a result of the cross guarantee agreement, a holder of any of the Guaranteed Notes issued by KMI or subsidiary issuers are in the same position with respect to the net assets, and income of KMI and the Subsidiary Issuers and Guarantors. The only amounts that are not available to the holders of each of the Guaranteed Notes to satisfy the repayment of such securities are the net assets, and income of the Subsidiary Non-Guarantors.

In lieu of providing separate financial statements for subsidiary issuers and guarantors, we have presented the accompanying supplemental summarized combined income statement and balance sheet information for the Obligated Group based on Rule 13-01 of the SEC's Regulation S-X that we early adopted effective January 1, 2020. Also, see Exhibit 10.14 to this Report "*Cross Guarantee Agreement, dated as of November 26, 2014, among KMI and certain of its subsidiaries, with schedules updated as of December 31, 2020.*"

All significant intercompany items among the Obligated Group have been eliminated in the supplemental summarized combined financial information. The Obligated Group's investment balances in Subsidiary Non-guarantors have been excluded from the supplemental summarized combined financial information. Significant intercompany balances and activity for the Obligated Group with other related parties, including Subsidiary Non-Guarantors, (referred to as "affiliates") are presented separately in the accompanying supplemental summarized combined financial information.

Excluding fair value adjustments, as of December 31, 2020 and 2019, the Obligated Group had $32,563 million and $32,409 million, respectively, of Guaranteed Notes outstanding.

Summarized combined balance sheet and income statement information for the Obligated Group follows:

	December 31,	
Summarized Combined Balance Sheet Information	**2020**	**2019**
	(In millions)	
Current assets	$ 2,957	$ 1,918
Current assets - affiliates	1,151	1,146
Noncurrent assets	61,783	63,298
Noncurrent assets - affiliates	616	441
Total Assets	$ 66,507	$ 66,803
Current liabilities	$ 4,528	$ 4,569
Current liabilities - affiliates	1,209	1,139
Noncurrent liabilities	33,907	33,612
Noncurrent liabilities - affiliates	1,078	1,325
Total Liabilities	40,722	40,645
Redeemable noncontrolling interest	728	803
Kinder Morgan, Inc.'s stockholders' equity	25,057	25,355
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 66,507	$ 66,803

Summarized Combined Income Statement Information	Year Ended December 31, 2020
	(In millions)
Revenues	$ 10,676
Operating income	1,932
Net income	654

Recent Accounting Pronouncements

Please refer to Note 19 *"Recent Accounting Pronouncements"* to our consolidated financial statements for information concerning recent accounting pronouncements.

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

Generally, our market risk sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in energy commodity prices or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in energy commodity prices or interest rates and the timing of transactions.

Energy Commodity Market Risk

We are exposed to energy commodity market risk and other external risks in the ordinary course of business. However, we manage these risks by executing a hedging strategy that seeks to protect us financially against adverse price movements and serves to minimize potential losses. Our strategy involves the use of certain energy commodity derivative contracts to reduce and minimize the risks associated with unfavorable changes in the market price of crude oil, natural gas and NGL. The derivative contracts that we use include exchange-traded and OTC commodity financial instruments, including, but not limited to, futures and options contracts, fixed price swaps and basis swaps. We may categorize such use of energy commodity derivative contracts as cash flow hedges because the derivative contract is used to hedge the anticipated future cash flow of a transaction that is expected to occur but which value is uncertain.

Our hedging strategy involves entering into a financial position intended to offset our physical position, or anticipated position, in order to minimize the risk of financial loss from an adverse price change. For example, as sellers of crude oil, natural gas and NGL, we often enter into fixed price swaps and/or futures contracts to guarantee or lock-in the sale price of our crude oil or the margin from the sale and purchase of our natural gas at the time of market delivery, thereby in whole or in part offsetting any change in prices, either positive or negative. Using derivative contracts for this purpose helps provide increased certainty with regard to operating cash flows which helps us to undertake further capital improvement projects, attain budget results and meet dividend targets.

Our policies require that derivative contracts are only entered into with carefully selected major financial institutions or similar counterparties based upon their credit ratings and other factors, and we maintain strict dollar and term limits that correspond to our counterparties' credit ratings. While it is our policy to enter into derivative transactions principally with investment grade counterparties and actively monitor their credit ratings, it is nevertheless possible that losses will result from counterparty credit risk in the future.

The credit ratings of the primary parties from whom we transact in energy commodity derivative contracts (based on contract market values) are as follows (credit ratings per Standard & Poor's Rating Service):

	Credit Rating
ING	A+
Citibank	A+
JP Morgan	A+
Bank of Nova Scotia	A+
Bank of America	A-

We measure the risk of price changes in the derivative instrument portfolios utilizing a sensitivity analysis model. The sensitivity analysis applied to each portfolio measures the potential income or loss (i.e., the change in fair value of the derivative instrument portfolio) based upon a hypothetical 10% movement in the underlying quoted market prices. In addition to these variables, the fair value of each portfolio is influenced by fluctuations in the notional amounts of the instruments and the discount rates used to determine the present values. Because we enter into derivative contracts largely for the purpose of mitigating the risks that accompany certain of our business activities, both in the sensitivity analysis model and in reality, the change in the market value of the derivative contracts' portfolio is offset largely by changes in the value of the underlying physical transactions. A hypothetical 10% movement in the underlying commodity prices would have the following effect on the associated derivative contracts' estimated fair value:

	As of December 31,	
Commodity derivative	**2020**	**2019**
	(In millions)	
Crude oil	$ 81	$ 113
Natural gas	12	8
NGL	7	7
Total	$ 100	$ 128

Our sensitivity analysis represents an estimate of the reasonably possible gains and losses that would be recognized on the crude oil, natural gas and NGL portfolios of derivative contracts assuming hypothetical movements in future market rates and is not necessarily indicative of actual results that may occur. It does not represent the maximum possible loss or any expected loss that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ from estimates due to actual fluctuations in market rates, operating exposures and the timing thereof, as well as changes in our portfolio of derivatives during the year.

Interest Rate Risk

In order to maintain a cost effective capital structure, it is our policy to borrow funds using a mix of fixed rate debt and variable rate debt. The market risk inherent in our debt instruments and positions is the potential change arising from increases or decreases in interest rates as discussed below.

For fixed rate debt, changes in interest rates generally affect the fair value of the debt instrument, but not our earnings or cash flows. Conversely, for variable rate debt, changes in interest rates generally do not impact the fair value of the debt instrument, but may affect our future earnings and cash flows. Generally, there is not an obligation to prepay fixed rate debt prior to maturity and, as a result, changes in fair value should not have a significant impact on the fixed rate debt. We are generally subject to interest rate risk upon refinancing maturing debt. Below are our debt balances, including debt fair value adjustments and, as of December 31, 2019, the preferred interest in KMP held by KMGP that was redeemed on January 15, 2020, and sensitivity to interest rates:

	December 31, 2020		December 31, 2019	
	Carrying value	**Estimated fair value(e)**	**Carrying value**	**Estimated fair value(e)**
		(In millions)		
Fixed rate debt(a)	$ 34,376	$ 39,306	$ 33,943	$ 37,588
Variable rate debt	$ 313	$ 316	$ 449	$ 428
Notional principal amount of variable-to-fixed interest rate swap agreements(b)	(2,750)		(250)	
Notional principal amount of fixed-to-variable interest rate swap agreements(c)	7,625		8,725	
Debt balances subject to variable interest rates(d)	$ 5,188		$ 8,924	

(a) A hypothetical 10% change in the average interest rates applicable to such debt as of December 31, 2020 and 2019, would result in changes of approximately $1,541 million and $1,548 million, respectively, in the estimated fair values of these instruments.
(b) December 31, 2020 amount includes $2.5 billion of variable-to-fixed interest rate swap agreements that expire during 2021.
(c) December 31, 2020 amount includes $900 million of fixed-to-variable interest rate swap agreements that expire during 2021.

(d) A hypothetical 10% change in the weighted average interest rate on all of our borrowings (approximately 49 and 53 basis points, respectively, in 2020 and 2019) when applied to our outstanding balance of variable rate debt as of December 31, 2020 and 2019, including adjustments for the notional swap amounts described above, would result in changes of approximately $25 million and $47 million, respectively, in our 2020 and 2019 annual income before income taxes.
(e) Fair values were determined using Level 2 inputs.

Fixed-to-variable interest rate swap agreements are entered into for the purpose of converting a portion of the underlying cash flows related to long-term fixed rate debt securities into variable rate debt in order to achieve our desired mix of fixed and variable rate debt. Since the fair value of fixed rate debt varies with changes in the market rate of interest, swap agreements are entered into to receive a fixed and pay a variable rate of interest. Such swap agreements result in future cash flows that vary with the market rate of interest, and therefore hedge against changes in the fair value of the fixed rate debt due to market rate changes.

As presented in the table above, we monitor the mix of fixed rate and variable rate debt obligations in light of changing market conditions and from time to time, may alter that mix by, for example, refinancing outstanding balances of variable rate debt with fixed rate debt (or vice versa) or by entering into interest rate swap agreements or other interest rate hedging agreements. As of December 31, 2020, including debt converted to variable rates through the use of interest rate swaps but excluding our debt fair value adjustments, approximately 16% of our debt balances were subject to variable interest rates.

For more information on our interest rate risk management and on our interest rate swap agreements, see Note 14 *"Risk Management"* to our consolidated financial statements.

LIBOR Phase Out

Amounts drawn under our revolving credit facility may bear interest rates in relation to U.S. Dollar LIBOR ("USD LIBOR"), depending on our selection of repayment options, and certain of our outstanding interest rate swap agreements have a floating interest rate in relation to one-month LIBOR or three-month LIBOR. In July 2017, the Financial Conduct Authority in the U.K. announced a desire to phase out LIBOR as a benchmark by the end of 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.

The agreement governing our revolving credit facility includes provisions to determine a replacement rate for LIBOR if necessary during its term, which require that we and our administrative agent agree upon a replacement rate based on the then-prevailing market convention for similar agreements, which rate is not objected to by lenders holding a majority of the revolving commitments. The International Swaps and Derivatives Association has developed provisions for SOFR-based fall-back rates to apply upon permanent cessation of LIBOR and has published a protocol to enable market participants to include the new provisions in existing swap agreements.

We currently do not expect the transition from LIBOR to have a material impact on us.

Foreign Currency Risk

As of December 31, 2020, we had a notional principal amount of $1,358 million of cross-currency swap agreements that effectively convert all of our fixed-rate Euro denominated debt, including annual interest payments and the payment of principal at maturity, to U.S. dollar denominated debt at fixed rates. These swaps eliminate the foreign currency risk associated with our foreign currency denominated debt.

Item 8. ***Financial Statements and Supplementary Data.***

The information required in this Item 8 is in this report as set forth in the "Index to Financial Statements" on page 72.

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

None.

Item 9A. *Controls and Procedures.*

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2020, our management, including our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15(b) under the Securities Exchange Act of 1934. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives. Based upon and as of the date of the evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the design and operation of our disclosure controls and procedures were effective to provide reasonable assurance that information required to be disclosed in the reports we file and submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported as and when required, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an assessment of the effectiveness of our internal control over financial reporting based on the framework in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management concluded that our internal control over financial reporting was effective as of December 31, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their audit report, which appears herein.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth quarter of 2020 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. *Other Information.*

None.

PART III

Item 10. *Directors, Executive Officers and Corporate Governance.*

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2021.

Item 11. *Executive Compensation.*

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2021.

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

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2021.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2021.

Item 14. ***Principal Accounting Fees and Services.***

The information required by this item is incorporated by reference from KMI's definitive proxy statement for the 2021 Annual Meeting of Stockholders, which shall be filed no later than April 30, 2021.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules.***

(a) (1) Financial Statements and (2) Financial Statement Schedules

See "Index to Financial Statements" set forth on Page 72.

(3) Exhibits

Exhibit Number		Description
3.1	*	Amended and Restated Certificate of Incorporation of KMI (filed as Exhibit 3.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081))
3.2	*	Amended and Restated Bylaws of KMI (filed as Exhibit 3.1 to KMI's Current Report on Form 8-K, filed October 20, 2017 (File No. 001-35081))
4.1	*	Form of certificate representing Class P common shares of KMI (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-1 filed on January 18, 2011 (File No. 333-170773))
4.2	*	Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-35081))
4.3	*	Amendment No. 1 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.3 to KMI's Current Report on Form 8-K filed on May 30, 2012 (File No. 001-35081))
4.4	*	Amendment No. 2 to the Shareholders Agreement among KMI and certain holders of common stock (filed as Exhibit 4.1 to KMI's Current Report on Form 8-K filed on December 3, 2014 (File No. 001-35081))
4.5	*	Indenture dated as of December 9, 2005, among Kinder Morgan Finance Company LLC (formerly Kinder Morgan Finance Company, ULC), Kinder Morgan Kansas, Inc. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
4.6	*	Forms of Kinder Morgan Finance Company LLC Notes (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Kansas, Inc.'s Current Report on Form 8-K filed on December 15, 2005 (File No. 1-06446))
4.7	*	Indenture dated January 2, 2001 between Kinder Morgan Energy Partners, L.P. and First Union National Bank, as trustee, relating to Senior Debt Securities (including form of Senior Debt Securities) (filed as Exhibit 4.11 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2000 (File No. 1-11234))
4.8	*	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.40% Notes due March 15, 2031 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001 (File No. 1-11234))
4.9	*	Specimen of 7.40% Notes due March 15, 2031 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Current Report on Form 8-K filed on March 14, 2001(File No. 1-11234))
4.10	*	Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Energy Partners, L.P. establishing the terms of the 7.750% Notes due March 15, 2032 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
4.11	*	Specimen of 7.750% Notes due March 15, 2032 in book-entry form (filed as Exhibit 4.3 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2002 (File No. 1-11234))
4.12	*	Indenture dated August 19, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.13	*	First Supplemental Indenture to Indenture dated August 19, 2002, dated August 23, 2002 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association, as Trustee (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))
4.14	*	Form of 7.30% Notes due 2033 (included in the Indenture filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-4 filed on October 4, 2002 (File No. 333-100346))

4.15 * Senior Indenture dated January 31, 2003 between Kinder Morgan Energy Partners, L.P. and Wachovia Bank, National Association (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))

4.16 * Form of Senior Note of Kinder Morgan Energy Partners, L.P. (included in the Form of Senior Indenture filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Registration Statement on Form S-3 filed on February 4, 2003 (File No. 333-102961))

4.17 * Certificate of the Vice President, Treasurer and Chief Financial Officer and the Vice President, General Counsel and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 5.80% Notes due March 15, 2035 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2005 (File No. 1-11234))

4.18 * Certificate of the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P. establishing the terms of the 6.00% Senior Notes due 2017 and 6.50% Senior Notes due 2037 (filed as Exhibit 4.28 to Kinder Morgan Energy Partners, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 1-11234))

4.19 * Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.95% Senior Notes due 2038 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2007 (File No. 1-11234))

4.20 * Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.80% Senior Notes due 2021, and the 6.50% Senior Notes due 2039 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2009 (File No. 1-11234))

4.21 * Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 5.30% Senior Notes due 2020, and the 6.55% Senior Notes due 2040 (filed as Exhibit 4.2 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended June 30, 2010 (File No. 1-11234))

4.22 * Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 6.375% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 1-11234))

4.23 * Certificate of the Vice President and Chief Financial Officer and the Vice President and Treasurer of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.150% Senior Notes due 2022, and the 5.625% Senior Notes due 2041 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2011 (File No. 1-11234))

4.24 * Certificate of the Vice President, Finance and Investor Relations and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 3.500% Senior Notes due 2021 and the 5.500% Senior Notes due 2044 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2014 (File No. 1-11234))

4.25 * Certificate of the Vice President and Treasurer and the Vice President and Secretary of Kinder Morgan Management, LLC and Kinder Morgan G.P., Inc., on behalf of Kinder Morgan Energy Partners, L.P., establishing the terms of the 4.250% Senior Notes due 2024 and the 5.400% Senior Notes due 2044 (filed as Exhibit 4.1 to Kinder Morgan Energy Partners, L.P.'s Quarterly Report on Form 10-Q for the quarter ended September 30, 2014 (File No. 1-11234))

4.26 * Indenture, dated March 1, 2012, between KMI and U.S. Bank National Association, as Trustee (filed as Exhibit 4.1 to KMI's Registration Statement on Form S-3 filed on March 1, 2012 (File No. 001-35081))

4.27 * Certificate of the Vice President and Treasurer and the Vice President and Secretary of KMI establishing the terms of the 2.000% Senior Notes due 2017, the 3.050% Senior Notes due 2019, the 4.300% Senior Notes due 2025, the 5.300% Senior Notes due 2034 and the 5.550% Senior Notes due 2045 (filed as Exhibit 10.53 to KMI's Annual Report on Form 10-K for the year ended December 31, 2014 (File No. 001-35081))

4.28 * Certificate of the Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 5.050% Senior Notes due 2046 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 (File No. 001-35081))

4.29	*	Certificate of the Vice President and Treasurer and Vice President and Secretary of KMI establishing the terms of the 1.500% Senior Notes due 2022 and 2.250% Senior Notes due 2027 (filed as Exhibit 4.2 to KMI's Form 8-A, filed March 16, 2015 (File No. 001-35081))
4.30	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 3.150% Senior Notes due January 15, 2023 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (File No. 001-35081))
4.31	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the Floating Rate Senior Notes due January 15, 2023 (filed as Exhibit 4.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2017 (File No. 001-35081))
4.32	*	Certificate of the Vice President and Treasurer and the Vice President and Chief Financial Officer of KMI establishing the terms of the 4.300% Senior Notes due 2028 and the 5.200% Senior Notes due 2048 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 (File No. 001-35081))
4.33	*	Certificate of the Vice President and Chief Financial Officer, and Vice President, Investor Relations and Treasurer of Kinder Morgan, Inc. establishing the terms of the 2.00% Notes due February 15, 2031 and the 3.25% Notes due August 1, 2050 (filed as Exhibit 4.1 to KMI's Quarterly Report on Form 10-Q for the quarter ended September 30, 2020 (File No. 001-35081))
4.34		Certain instruments with respect to long-term debt of KMI and its consolidated subsidiaries which relate to debt that does not exceed 10% of the total assets of KMI and its consolidated subsidiaries are omitted pursuant to Item 601(b) (4) (iii) (A) of Regulation S-K, 17 C.F.R. sec. #229.601. KMI hereby agrees to furnish supplementally to the Securities and Exchange Commission a copy of each such instrument upon request.
4.35	*	Description of Capital Stock of Kinder Morgan, Inc. Registered Pursuant to Section 12 of the Securities Exchange Act of 1934
4.36	*	Description of Debt Securities of Kinder Morgan, Inc. Registered Pursuant to Section 12 of the Securities Exchange Act of 1934
10.1	*	KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 4.5 to KMI's Registration Statement on Form S-8, filed on July 1, 2015 (File No. 333-205430))
10.2	*	Amendment No. 1 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI's Current Report on Form 8-K filed on January 24, 2017 (File No. 001-35081))
10.3	*	Amendment No. 2 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 (File No. 001-35081))
10.4	*	Amendment No. 3 to KMI 2015 Amended and Restated Stock Incentive Plan (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed on January 22, 2019 (File No. 001-35081))
10.5	*	2015 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 4.6 to KMI's Registration Statement on Form S-8, filed on July 1, 2015 (File No. 333-205430))
10.6	*	2016 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.2 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2016 (File No. 001-35081))
10.7	*	2018 Form of Employee Restricted Stock Unit Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 (File No. 001-35081))
10.8	*	Amended and Restated Stock Compensation Plan for Non-Employee Directors (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081))
10.9	*	2015 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.6 to KMI's Quarterly Report on Form 10-Q for the quarter ended June 30, 2015 (File No. 001-35081))
10.10	*	2011 Form of Non-Employee Director Stock Compensation Agreement (filed as Exhibit 10.3 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-35081))
10.11	*	KMI Employees Stock Purchase Plan (filed as Exhibit 10.5 to KMI's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 (File No. 001-35081))
10.12	*	Amended and Restated Annual Incentive Plan of KMI (filed as Exhibit 10.1 to KMI's Current Report on Form 8-K filed January 26, 2021 (File No. 001-35081))
10.13	*	Revolving Credit Agreement, dated November 16, 2018 among KMI, as borrower, Barclays Bank PLC, as administrative agent, and the lenders and issuing banks party thereto (filed as Exhibit 10.15 to KMI's Annual Report on Form 10-K for the year ended December 31, 2018 (File No. 001-35081))
10.14		Cross Guarantee Agreement, dated as of November 26, 2014 among KMI and certain of its subsidiaries with schedules updated as of December 31, 2020

21.1	Subsidiaries of KMI
22.1	Subsidiary guarantors and issuers of guaranteed securities
23.1	Consent of PricewaterhouseCoopers LLP
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
32.1	Certification of Chief Executive Officer 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 pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101	Interactive data files pursuant to Rule 405 of Regulation S-T formatted in iXBRL (Inline Extensible Business Reporting Language): (i) our Consolidated Statements of Income for the years ended December 31, 2020, 2019, and 2018; (ii) our Consolidated Statements of Comprehensive Income for the years ended December 31, 2020, 2019, and 2018; (iii) our Consolidated Balance Sheets as of December 31, 2020 and 2019; (iv) our Consolidated Statements of Cash Flows for the years ended December 31, 2020, 2019, and 2018; (v) our Consolidated Statements of Stockholders' Equity as of and for the years ended December 31, 2020, 2019, and 2018; and (vi) the notes to our Consolidated Financial Statements
104	Cover Page Interactive Data File pursuant to Rule 406 of Regulation S-T formatted in iXBRL (Inline Extensible Business Reporting Language) and contained in Exhibit 101.

*Asterisk indicates exhibits incorporated by reference as indicated; all other exhibits are filed herewith, except as noted otherwise.

KINDER MORGAN, INC. AND SUBSIDIARIES
INDEX TO FINANCIAL STATEMENTS AND SUPPLEMENTARY QUARTERLY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Kinder Morgan, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of Kinder Morgan, Inc. and its subsidiaries (the "Company") as of December 31, 2020 and 2019, and the related consolidated statements of income, of comprehensive income, of stockholders' equity and of cash flows for each of the three years in the period ended December 31, 2020, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting 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 Company 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 audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements 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. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters 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 matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Impairment of Certain Oil and Gas Producing Properties

As described in Notes 2 and 3 to the consolidated financial statements, the Company recognized $350 million of impairments on the income statement within “Loss (gain) on impairments and divestitures, net” for the year ended December 31, 2020 related to certain oil and gas producing properties included on the balance sheet under “Property, plant and equipment, net.” Management accounts for their oil and gas producing properties under the successful efforts method of accounting and evaluates such properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on future oil and gas production volumes. To compute estimated future cash flows for oil and gas producing properties, management used reserve engineers (“specialists”) to estimate future oil and gas production volumes. These estimates of future oil and gas production volumes are based upon historical performance along with adjustments for expected crude oil and natural gas field development.

The principal considerations for our determination that performing procedures relating to the impairment of certain oil and gas producing properties that were impaired is a critical audit matter are (i) the significant judgment by management, including the use of specialists, when developing the fair value of the oil and gas producing properties; which in turn led to (ii) a high degree of auditor judgment, subjectivity, and effort in performing procedures and evaluating the audit evidence related to the data, methods, and significant assumptions used by management and its specialists in developing the estimates of future oil and gas production volumes.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management’s impairment assessment of oil and gas producing properties, including management’s estimates of future oil and gas production volumes. The work of management’s specialist was used in performing the procedures to evaluate the reasonableness of the future oil and gas production volumes. As a basis for using this work, the specialists’ qualifications were understood and the Company’s relationship with the specialists was assessed. The procedures performed also included evaluation of methods and assumptions used by the specialist, tests of the data used by the specialists, and an evaluation of the specialists’ findings. These procedures also included, among others (i) testing management’s process for determining the fair value of the oil and gas producing properties; (ii) evaluating the appropriateness of the discounted cash flow model; (iii) testing the completeness and accuracy of the underlying data used in the model; and (iv) evaluating the reasonableness of management’s estimate of future oil and gas production volumes which involved considering the current and past performance of the oil and gas producing properties and whether this was consistent with evidence obtained in other areas of the audit.

Goodwill Impairment of the CO_2 Reporting Unit

As described in Notes 2, 3 and 8 to the consolidated financial statements, the Company’s consolidated goodwill balance was $19,851 million as of December 31, 2020, which included a $600 million impairment recorded on the CO_2 reporting unit within “Loss (gain) on impairments and divestitures, net” for the year ended December 31, 2020. Management evaluates goodwill for impairment on May 31 of each year, or more frequently to the extent events or conditions indicate a risk of possible impairment during the interim periods. Management estimates the fair value of the CO_2 reporting unit based on an income approach utilizing the present value of future cash flows from its oil and gas producing properties and source and transportation assets. To compute estimated future cash flows for oil and gas producing properties, management used reserve engineers (“specialists”) to estimate future oil and gas production volumes. These estimates of future oil and gas production volumes are based upon historical performance along with adjustments for expected crude oil and natural gas field development. The future cash flows for the source and transportation assets are based on forecasted throughput volumes, CO_2 pricing, operating expenses and capital expenditures.

The principal considerations for our determination that performing procedures relating to the goodwill impairment of the CO_2 reporting unit is a critical audit matter are the significant judgment by management, including the use of specialists, when developing the fair value measurement of the reporting unit, which included the (i) estimates of the future oil and gas production volumes of oil and gas producing properties; and (ii) the significant assumption related to the forecasted throughput volumes for the source and transportation assets; which in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating the audit evidence related to (i) the data, methods, and significant assumption used by management and its specialists in developing the estimates of future oil and gas production volumes of the oil and gas producing properties; and (ii) the significant assumption related to forecasted throughput volumes for the source and transportation assets.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment assessment. The work of management's specialist was used in performing the procedures to evaluate the reasonableness of the future oil and gas production volumes related to the oil and gas producing properties. As a basis for using this work, the specialists' qualifications were understood and the Company's relationship with the specialists was assessed. The procedures performed also included evaluation of the methods and assumptions used, tests of the data used by specialists, and an evaluation of the specialists' findings. These procedures also included, among others, (i) testing management's process for developing the overall fair value estimate of the reporting unit, which includes the estimates of future oil and gas production volumes and the significant assumption related to the forecasted throughput volumes; (ii) testing the completeness and accuracy of the underlying data used in the model; and (iii) evaluating the reasonableness of the estimate of the future oil and gas production volumes and the significant assumption related to the forecasted throughput volumes. Evaluating management's estimates and assumptions related to the future oil and gas production volumes and forecasted throughput volumes involved evaluating whether the assumptions used by management were reasonable considering the current and past performance of the oil and gas producing properties and the source and transportation assets and whether these assumptions were consistent with evidence obtained in other areas of the audit.

Goodwill Impairment of the Natural Gas Pipelines Non-Regulated Reporting Unit

As described in Notes 2, 3 and 8 to the consolidated financial statements, the Company's consolidated goodwill balance was $19,851 million as of December 31, 2020, which included a $1,000 million impairment recorded on the Natural Gas Pipelines Non-Regulated reporting unit within "Loss (gain) on impairments and divestitures, net" for the year ended December 31, 2020. Management evaluates goodwill for impairment on May 31 of each year, or more frequently to the extent events or conditions indicate a risk of possible impairment during the interim periods. Management estimated the fair value of the Natural Gas Pipelines Non-Regulated reporting unit utilizing a weighted average of a market approach (25%) and income approach (75%). The market approach was based on enterprise value to estimated 2020 earnings before interest, taxes, depreciation and amortization (EBITDA) multiples for a selected number of peer group midstream companies with comparable operations and economic characteristics. The income approach was based on an analysis of estimated discounted cash flows and an application of an exit multiple based on management's expectations of a discount rate and exit multiple that would be applied by a theoretical market participant and for market transactions of comparable assets. The discounted cash flows included various assumptions on forecasted commodity throughput volumes and contract prices for each underlying asset within the reporting unit.

The principal considerations for our determination that performing procedures relating to the goodwill impairment assessment of the Natural Gas Pipelines Non-Regulated reporting unit is a critical audit matter are (i) the significant judgment by management when developing the fair value measurement of the reporting unit utilizing the income approach; and (ii) a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating management's significant assumptions related to forecasted commodity throughput volumes and forecasted contract prices.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's goodwill impairment assessment, including controls over the valuation of the Natural Gas Pipelines Non-Regulated reporting unit. These procedures also included, among others (i) testing management's process for developing the fair value estimate; (ii) evaluating the appropriateness of the discounted cash flow model; (iii) testing the completeness and accuracy of the underlying data used in the model; and (iv) evaluating the reasonableness of significant assumptions related to the forecasted commodity throughput volumes and forecasted contract prices. Evaluating management's significant assumptions related to forecasted commodity throughput volumes and forecasted contract prices involved evaluating whether the assumptions used by management were reasonable considering (i) the current and past performance of the reporting unit; (ii) the consistency with external market and industry data; and (iii) whether these assumptions were consistent with evidence obtained in other areas of the audit.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 5, 2021

We have served as the Company's auditor since 1997.

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
(In millions, except per share amounts)

	Year Ended December 31,		
	2020	**2019**	**2018**
Revenues			
Services	$ 7,618	$ 8,198	$ 7,955
Commodity sales	3,891	4,811	5,987
Other	191	200	202
Total Revenues	11,700	13,209	14,144
Operating Costs, Expenses and Other			
Costs of sales	2,545	3,263	4,421
Operations and maintenance	2,475	2,591	2,522
Depreciation, depletion and amortization	2,164	2,411	2,297
General and administrative	648	590	601
Taxes, other than income taxes	378	426	345
Loss (gain) on impairments and divestitures, net (Note 3)	1,932	(942)	167
Other income, net	(2)	(3)	(3)
Total Operating Costs, Expenses and Other	10,140	8,336	10,350
Operating Income	1,560	4,873	3,794
Other Income (Expense)			
Earnings from equity investments	780	101	617
Amortization of excess cost of equity investments	(140)	(83)	(95)
Interest, net	(1,595)	(1,801)	(1,917)
Other, net	56	75	107
Total Other Expense	(899)	(1,708)	(1,288)
Income Before Income Taxes	661	3,165	2,506
Income Tax Expense	(481)	(926)	(587)
Net Income	180	2,239	1,919
Net Income Attributable to Noncontrolling Interests	(61)	(49)	(310)
Net Income Attributable to Kinder Morgan, Inc.	119	2,190	1,609
Preferred Stock Dividends	—	—	(128)
Net Income Available to Common Stockholders	$ 119	$ 2,190	$ 1,481
Class P Shares			
Basic and Diluted Earnings Per Common Share	$ 0.05	$ 0.96	$ 0.66
Basic and Diluted Weighted Average Common Shares Outstanding	2,263	2,264	2,216

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(In millions)

	Year Ended December 31,		
	2020	**2019**	**2018**
Net income	$ 180	$ 2,239	$ 1,919
Other comprehensive (loss) income, net of tax			
Change in fair value of hedge derivatives (net of tax (expense) benefit of $(75), $52, and $(34), respectively)	249	(177)	111
Reclassification of change in fair value of derivatives to net income (net of tax benefit (expense) of $78, $(2), and $(25), respectively)	(255)	6	84
Foreign currency translation adjustments (net of tax expense of $—, $27, and $16, respectively)	—	108	141
Benefit plan adjustments (net of tax benefit (expense) of $19, $(23), and $(11), respectively)	(68)	77	2
Total other comprehensive (loss) income	(74)	14	338
Comprehensive income	106	2,253	2,257
Comprehensive income attributable to noncontrolling interests	(61)	(66)	(328)
Comprehensive income attributable to KMI	$ 45	$ 2,187	$ 1,929

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
(In millions, except share and per share amounts)

	December 31,	
	2020	**2019**
ASSETS		
Current assets		
Cash and cash equivalents	$ 1,184	$ 185
Restricted deposits	25	24
Marketable securities at fair value	—	925
Accounts receivable	1,293	1,379
Fair value of derivative contracts	185	84
Inventories	348	371
Other current assets	168	270
Total current assets	3,203	3,238
Property, plant and equipment, net	35,836	36,419
Investments	7,917	7,759
Goodwill	19,851	21,451
Other intangibles, net	2,453	2,676
Deferred income taxes	536	857
Deferred charges and other assets	2,177	1,757
Total Assets	$ 71,973	$ 74,157
LIABILITIES, REDEEMABLE NONCONTROLLING INTEREST AND STOCKHOLDERS' EQUITY		
Current liabilities		
Current portion of debt	$ 2,558	$ 2,477
Accounts payable	837	914
Accrued interest	525	548
Accrued taxes	267	364
Accrued contingencies	307	89
Other current liabilities	580	708
Total current liabilities	5,074	5,100
Long-term liabilities and deferred credits		
Long-term debt		
Outstanding	30,838	30,883
Debt fair value adjustments	1,293	1,032
Total long-term debt	32,131	31,915
Other long-term liabilities and deferred credits	2,202	2,253
Total long-term liabilities and deferred credits	34,333	34,168
Total Liabilities	39,407	39,268
Commitments and contingencies (Notes 9, 13, 17 and 18)		
Redeemable Noncontrolling Interest	728	803
Stockholders' Equity		
Class P shares, $0.01 par value, 4,000,000,000 shares authorized, 2,264,257,336 and 2,264,936,054 shares, respectively, issued and outstanding	23	23
Additional paid-in capital	41,756	41,745
Accumulated deficit	(9,936)	(7,693)
Accumulated other comprehensive loss	(407)	(333)
Total Kinder Morgan, Inc.'s stockholders' equity	31,436	33,742
Noncontrolling interests	402	344
Total Stockholders' Equity	31,838	34,086
Total Liabilities, Redeemable Noncontrolling Interest and Stockholders' Equity	$ 71,973	$ 74,157

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2020	2019	2018
Cash Flows From Operating Activities			
Net income	$ 180	$ 2,239	$ 1,919
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation, depletion and amortization	2,164	2,411	2,297
Deferred income taxes	345	717	405
Amortization of excess cost of equity investments	140	83	95
Change in fair market value of derivative contracts	(5)	(22)	77
Loss (gain) on divestitures and impairments, net (Note 3)	1,932	(942)	167
Earnings from equity investments	(780)	(101)	(617)
Distributions of equity investment earnings	633	590	499
Pension (contributions) net of noncash pension benefit expenses	(90)	14	(4)
Changes in components of working capital, net of the effects of acquisitions and dispositions			
Accounts receivable	88	98	(45)
Income tax receivable	—	—	137
Inventories	16	4	15
Other current assets	49	100	(21)
Accounts payable	(19)	(198)	21
Accrued interest, net of interest rate swaps	(51)	(43)	(22)
Accrued taxes	(93)	(142)	241
Accrued contingencies and other current liabilities	(113)	(69)	73
Other, net	154	9	(194)
Net Cash Provided by Operating Activities	4,550	4,748	5,043
Cash Flows From Investing Activities			
Capital expenditures	(1,707)	(2,270)	(2,904)
Sales of property, plant and equipment, investments, and other net assets, net of removal costs	1,069	110	104
Proceeds from the KML and U.S. Cochin Sale, net of cash disposed (Note 4)	—	1,527	—
Proceeds from the TMPL Sale, net of cash disposed and working capital adjustments (Note 4)	—	(28)	2,998
Acquisitions of assets and investments	(16)	(79)	(39)
Contributions to investments	(386)	(1,299)	(433)
Distributions from equity investments in excess of cumulative earnings	154	333	237
Other, net	(25)	(8)	(31)
Net Cash Used in Investing Activities	(911)	(1,714)	(68)
Cash Flows From Financing Activities			
Issuances of debt	3,888	8,036	14,751
Payments of debt	(3,996)	(11,224)	(14,591)
Debt issue costs	(25)	(10)	(42)
Cash dividends - common shares (Note 11)	(2,362)	(2,163)	(1,618)
Cash dividends - preferred shares (Note 11)	—	—	(156)
Repurchases of common shares	(50)	(2)	(273)
Contributions from investment partner and noncontrolling interests	14	151	200
Distributions to investment partner	(79)	(11)	—
Distribution to noncontrolling interests - KML distribution of the TMPL Sale proceeds	—	(879)	—
Distributions to noncontrolling interests - other	(15)	(55)	(78)
Other, net	(13)	(28)	(17)
Net Cash Used in Financing Activities	(2,638)	(6,185)	(1,824)
Effect of Exchange Rate Changes on Cash, Cash Equivalents and Restricted Deposits	(1)	29	(146)
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	1,000	(3,122)	3,005
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	209	3,331	326
Cash, Cash Equivalents, and Restricted Deposits, end of period	$ 1,209	$ 209	$ 3,331

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS (continued)
(In millions)

	Year Ended December 31,		
	2020	2019	2018
Cash and Cash Equivalents, beginning of period	$ 185	$ 3,280	$ 264
Restricted Deposits, beginning of period	24	51	62
Cash, Cash Equivalents, and Restricted Deposits, beginning of period	209	3,331	326
Cash and Cash Equivalents, end of period	1,184	185	3,280
Restricted Deposits, end of period	25	24	51
Cash, Cash Equivalents, and Restricted Deposits, end of period	1,209	209	3,331
Net increase (decrease) in Cash, Cash Equivalents and Restricted Deposits	$ 1,000	$ (3,122)	$ 3,005
Noncash Investing and Financing Activities			
ROU assets and operating lease obligations recognized (Note 17)	$ 20	$ 399	
Marketable securities obtained as consideration for divestiture (Note 4)	—	892	$ —
Decrease in noncontrolling interests for distribution accrual	—	—	905
Supplemental Disclosures of Cash Flow Information			
Cash paid during the period for interest (net of capitalized interest)	1,661	1,860	1,879
Cash paid (refunded) during the period for income taxes, net	227	372	(109)

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

KINDER MORGAN, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
(In millions)

	Preferred stock		Common stock							
	Issued shares	Par value	Issued shares	Par value	Additional paid-in capital	Accumulated deficit	Accumulated other comprehensive loss	Stockholders' equity attributable to KMI	Non-controlling interests	Total
Balance at December 31, 2017	2	$ —	2,217	$ 22	$ 41,909	$ (7,754)	$ (541)	$ 33,636	$ 1,488	$ 35,124
Impact of adoption of ASU (Note 11)						175	(109)	66		66
Balance at January 1, 2018	2	—	2,217	22	41,909	(7,579)	(650)	33,702	1,488	35,190
Repurchases of shares			(15)		(273)			(273)		(273)
Mandatory conversion of preferred shares	(2)		58	1	(1)			—		—
Restricted shares			2		65			65		65
Net income						1,609		1,609	310	1,919
Distributions								—	(997)	(997)
Contributions								—	33	33
Preferred stock dividends						(128)		(128)		(128)
Common stock dividends						(1,618)		(1,618)		(1,618)
Other					1			1	1	2
Other comprehensive income							320	320	18	338
Balance at December 31, 2018	—	—	2,262	23	41,701	(7,716)	(330)	33,678	853	34,531
Impact of adoption of ASU						(4)		(4)		(4)
Balance at January 1, 2019	—	—	2,262	23	41,701	(7,720)	(330)	33,674	853	34,527
Repurchases of shares					(2)			(2)		(2)
Restricted shares			3		46			46		46
Net income						2,190		2,190	49	2,239
Distributions								—	(55)	(55)
Contributions								—	3	3
Common stock dividends						(2,163)		(2,163)		(2,163)
Sale of interest in KML							68	68	(503)	(435)
Other								—	1	1
Other comprehensive loss							(71)	(71)	(4)	(75)
Balance at December 31, 2019	—	—	2,265	23	41,745	(7,693)	(333)	33,742	344	34,086
Repurchases of shares			(4)		(50)			(50)		(50)
Restricted shares			3		61			61		61
Net income						119		119	61	180
Distributions								—	(15)	(15)
Contributions								—	11	11
Common stock dividends						(2,362)		(2,362)		(2,362)
Other								—	1	1
Other comprehensive loss							(74)	(74)		(74)
Balance at December 31, 2020	—	$ —	2,264	$ 23	$ 41,756	$ (9,936)	$ (407)	$ 31,436	$ 402	$ 31,838

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

KINDER MORGAN, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. General

We are one of the largest energy infrastructure companies in North America and unless the context requires otherwise, references to “we,” “us,” “our,” “the Company,” or “KMI” are intended to mean Kinder Morgan, Inc. and its consolidated subsidiaries. Our pipelines transport natural gas, refined petroleum products, crude oil, condensate, CO_2 and other products, and our terminals store and handle various commodities including gasoline, diesel fuel, chemicals, metals and petroleum coke.

2. Summary of Significant Accounting Policies

Basis of Presentation

Our reporting currency is U.S. dollars, and all references to dollars are U.S. dollars, unless stated otherwise. Our accompanying consolidated financial statements have been prepared under the rules and regulations of the SEC. These rules and regulations conform to the accounting principles contained in the FASB’s Accounting Standards Codification (ASC), the single source of GAAP. Under such rules and regulations, all significant intercompany items have been eliminated in consolidation. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

COVID-19

The COVID-19 pandemic-related reduction in energy demand and the dramatic decline in commodity prices that began to impact us in the first quarter of 2020 has continued to cause disruptions and volatility. Sharp declines in crude oil and natural gas production along with reduced demand for refined products due to the economic shutdown in the wake of the pandemic affected our business and continues to do so. While we have seen some meaningful recovery during the second half of the year in demand for refined products that we move through our terminals, significant uncertainty remains regarding the duration and extent of the impact of the pandemic (including the timing and distribution of vaccines) on the energy industry, including demand and prices for the products handled by our pipelines, terminals, shipping vessels and other facilities. These events, among other factors, resulted in certain non-cash impairments charges during 2020 as further discussed in Note 3.

Use of Estimates

Certain amounts included in or affecting our financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions which cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for assets and liabilities, our revenues and expenses during the reporting period, and our disclosures, including as it relates to contingent assets and liabilities at the date of our financial statements. We evaluate these estimates on an ongoing basis, utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates. Any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

Certain accounting policies are of more significance in our financial statement preparation process than others, and set out below are the principal accounting policies we apply in the preparation of our consolidated financial statements.

Cash Equivalents and Restricted Deposits

We define cash equivalents as all highly liquid short-term investments with original maturities of three months or less.

Amounts included in the restricted deposits in the accompanying consolidated financial statements represent a combination of restricted cash amounts required to be set aside by regulatory agencies to cover obligations for our captive insurance subsidiary and cash margin deposits posted by us with our counterparties associated with certain energy commodity contract positions.

Allowance for Credit Losses

Effective with our adoption of Accounting Standards Update (ASU) No. 2016-13, "*Financial Instruments–Credit Losses*" on January 1, 2020, we evaluate our financial assets measured at amortized cost and off-balance sheet credit exposures for expected credit losses over the contractual term of the asset or exposure. We consider available information relevant to assessing the collectability of cash flows including the expected risk of credit loss even if that risk is remote. We measure expected credit losses on a collective (pool) basis when similar risk characteristics exist and we reflect the expected credit losses on the amortized cost basis of the financial asset as of the reporting date.

Our financial instruments primarily consist of our accounts receivable from customers, notes receivable from affiliates, and contingent liabilities such as proportional guarantees of debt obligations of certain equity investees. We utilized historical analysis of credit losses experienced over the previous five years along with current conditions and reasonable and supportable forecasts of future conditions in our evaluation of collectability of our financial assets. Our allowance for credit losses as of December 31, 2020 includes an evaluation of estimated impacts resulting from the energy production and demand factors related to COVID-19 and the sharp decline in commodity prices, which we estimate could have a more significant impact to certain subset or pools of customers.

Prior to the adoption of ASU No. 2016-13, generally our evaluation of appropriate reserves for our accounts receivable was based on a historical analysis of uncollected amounts and we recorded adjustments for changed circumstances and customer-specific information.

Our allowance for credit losses as of December 31, 2020 and 2019 was $26 million and $9 million, respectively, included in "Other current assets" in our accompanying consolidated balance sheets.

Inventories

Our inventories consist of materials and supplies and products such as NGL, crude oil, condensate, refined petroleum products, transmix and natural gas. We report products inventory at the lower of weighted-average cost or net realizable value. We report materials and supplies inventories at cost, and periodically review for physical deterioration and obsolescence.

Property, Plant and Equipment, net

Capitalization, Depreciation and Depletion and Disposals

We report property, plant and equipment at its acquisition cost. We expense costs for routine maintenance and repairs in the period incurred.

We generally compute depreciation using either the straight-line method based on estimated economic lives or the composite depreciation method, which applies a single depreciation rate for a group of assets. Generally, we apply composite depreciation rates to functional groups of property having similar economic characteristics. The rates range from 0.08% to 33.3% excluding certain short-lived assets such as vehicles. For FERC-regulated entities, the FERC-accepted composite depreciation rate is applied to the total cost of the composite group until the net book value equals the salvage value. For other entities, depreciation estimates are based on various factors, including age (in the case of acquired assets), manufacturing specifications, technological advances, estimated production life of the oil or gas field served by the asset, contract term for assets on leased or customer property and historical data concerning useful lives of similar assets. Uncertainties that impact these estimates include changes in laws and regulations relating to restoration and abandonment requirements, economic conditions, and supply and demand in the area. When these assets are put into service, we make estimates with respect to useful lives (and salvage values where appropriate) that we believe are reasonable. Subsequent events could cause us to change our estimates, thus impacting the future calculation of depreciation and amortization expense. Historically, adjustments to useful lives have not had a material impact on our aggregate depreciation levels from year to year.

Our oil and gas producing activities are accounted for under the successful efforts method of accounting. Under this method, costs that are incurred to acquire leasehold and subsequent development costs are capitalized. Costs that are associated with the drilling of successful exploration wells are capitalized if proved reserves are found. Costs associated with the drilling of exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of certain non-producing leasehold costs are expensed as incurred. The capitalized costs of our producing oil and gas properties are depreciated and depleted by the units-of-production method. Other miscellaneous property, plant and equipment are depreciated over the estimated useful lives of the asset.

We engage in enhanced recovery techniques in which CO_2 is injected into certain producing oil reservoirs. In some cases, the cost of the CO_2 associated with enhanced recovery is capitalized as part of our development costs when it is injected. The cost of CO_2 associated with pressure maintenance operations for reservoir management is expensed when it is injected. When CO_2 is recovered in conjunction with oil production, it is extracted and re-injected, and all of the associated costs are expensed as incurred. Proved developed reserves are used in computing units of production rates for drilling and development costs, and total proved reserves are used for depletion of leasehold costs.

A gain on the sale of property, plant and equipment used in our oil and gas producing activities or in our liquids and bulk terminal activities is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received. A gain on an asset disposal is recognized in income in the period that the sale is closed. A loss on the sale of property, plant and equipment is calculated as the difference between the cost of the asset disposed of, net of depreciation, and the sales proceeds received or the market value if the asset is being held for sale. A loss is recognized when the asset is sold or when the net cost of an asset held for sale is greater than the market value of the asset. For our pipeline system assets under the composite method of depreciation, we generally charge the original cost of property sold or retired to accumulated depreciation and amortization, net of salvage and cost of removal. Gains and losses are booked for FERC-approved operating unit sales and land sales and are recorded to income or expense accounts in accordance with regulatory accounting guidelines.

Asset Retirement Obligations

We record liabilities for obligations related to the retirement and removal of long-lived assets used in our businesses. We record, as liabilities, the fair value of asset retirement obligations on a discounted basis when they are incurred and can be reasonably estimated, which is typically at the time the assets are installed or acquired. Amounts recorded for the related assets are increased by the amount of these obligations. Over time, the liabilities increase due to the change in their present value, and the initial capitalized costs are depreciated over the useful lives of the related assets. The liabilities are eventually extinguished when the asset is taken out of service.

We have various other obligations throughout our businesses to remove facilities and equipment on rights-of-way and other leased facilities. We currently cannot reasonably estimate the fair value of these obligations because the associated assets have indeterminate lives. These assets include pipelines, certain processing plants and distribution facilities, and certain liquids and bulk terminal facilities. An asset retirement obligation, if any, will be recognized once sufficient information is available to reasonably estimate the fair value of the obligation.

Long-lived Asset and Other Intangibles Impairments

We evaluate long-lived assets including leases and investments for impairment whenever events or changes in circumstances indicate that our carrying amount of an asset or investment may not be recoverable. We recognize impairment losses when estimated future cash flows expected to result from our use of the asset and its eventual disposition is less than its carrying amount.

In addition to our annual goodwill impairment test, to the extent triggering events exist, we complete a review of the carrying value of our long-lived assets, including property, plant and equipment as well as other intangibles, and record, as applicable, the appropriate impairments. Because the impairment test for long-lived assets held in use is based on undiscounted cash flows, there may be instances where an asset or asset group is not considered impaired, even when its fair value may be less than its carrying value, because the asset or asset group is recoverable based on the cash flows to be generated over the estimated life of the asset or asset group. If the carrying value of a long-lived asset or asset group is in excess of undiscounted cash flows, we typically use discounted cash flow analyses to determine if an impairment is required.

We evaluate our oil and gas producing properties for impairment of value on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure, using undiscounted future cash flows based on estimated future oil and gas production volumes.

Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future cash flows based on estimated future oil and gas production volumes. Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment.

Refer to Note 3 for further information.

Equity Method of Accounting and Basis Differences

We account for investments which we do not control, but do have the ability to exercise significant influence using the equity method of accounting. The carrying values of these investments are impacted by our share of investee income or loss, distributions, amortization or accretion of basis differences and other-than-temporary impairments.

The difference between the carrying value of an investment and our share of the investment's underlying equity in net assets is referred to as a basis difference. If the basis difference is assigned to depreciable or amortizable assets and liabilities, the basis difference is amortized or accreted as part of our share of investee earnings. To the extent that the basis difference relates to goodwill, referred to as equity method goodwill, the amount is not amortized.

We evaluate our equity method investments for other-than-temporary impairment. When an other-than-temporary impairment is recognized the loss is recorded as a reduction in equity earnings.

Goodwill

Goodwill is the cost of an acquisition of a business in excess of the fair value of acquired assets and liabilities and is recorded as an asset on our balance sheet. Goodwill is not subject to amortization but must be tested for impairment at least annually and in interim periods if indicators of impairment exist. This test requires us to assign goodwill to an appropriate reporting unit, and an impairment exists and is recorded for the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill.

We evaluate goodwill for impairment on May 31 of each year. For this purpose, we have six reporting units as follows: (i) Products Pipelines (excluding associated terminals); (ii) Products Pipelines Terminals (evaluated separately from Products Pipelines for goodwill purposes); (iii) Natural Gas Pipelines Regulated; (iv) Natural Gas Pipelines Non-Regulated; (v) CO_2; and (vi) Terminals. We also evaluate goodwill for impairment to the extent events or conditions change between annual tests that would indicate a risk of possible impairment at the interim period. Generally, the evaluation of goodwill for impairment involves a quantitative test, although under certain circumstance an initial qualitative evaluation may be sufficient to conclude that goodwill is not impaired without conducting the quantitative test.

Prior to our adoption of ASU No. 2017-04, "*Intangibles - Goodwill and Other (Topic) 350: Simplifying the Test for Goodwill Impairment*" effective January 1, 2020, we performed a two-step quantitative test. Step 1 involved the quantitative test still applied under ASU No. 2017-04 described above. If the estimated fair value exceeded the carrying value, the reporting unit's goodwill was not considered impaired. If the carrying value exceeded the estimated fair value, step 2 was performed to determine whether goodwill was impaired and, if so, the amount of the impairment. Step 2 involved calculating an implied fair value of goodwill by performing a hypothetical allocation of the estimated fair value of the reporting unit determined in step 1 to the respective tangible and intangible net assets of the reporting unit. The remaining implied goodwill was then compared to the actual carrying amount of the goodwill for the reporting unit. To the extent the carrying amount of goodwill exceeded the implied goodwill, the difference was the amount of the goodwill impairment.

A large portion of our goodwill is non-deductible for tax purposes, and as such, to the extent there are impairments, all or a portion of the impairment may not result in a corresponding tax benefit.

Refer to Note 8 for further information.

Other Intangibles

Excluding goodwill, our other intangible assets include customer contracts, relationships and agreements, and technology-based assets. As of both December 31, 2020 and 2019, the gross carrying amounts of these intangible assets was $4,074 million and $4,126 million, respectively, and the accumulated amortization was $1,621 million and $1,450 million, respectively, resulting in net carrying amounts of $2,453 million and $2,676 million, respectively. These intangible assets primarily consisted of customer contracts, relationships and agreements associated with our Natural Gas Pipelines and Product Pipelines business segments.

Primarily, these contracts, relationships and agreements relate to the gathering of natural gas, and the handling and storage of petroleum, chemical, and dry-bulk materials, including oil, gasoline and other refined petroleum products, petroleum coke, metals and ores. We determined the values of these intangible assets by first, estimating the revenues derived from a customer contract or relationship (offset by the cost and expenses of supporting assets to fulfill the contract), and second, discounting the revenues at a risk adjusted discount rate.

We amortize the costs of our intangible assets to expense in a systematic and rational manner over their estimated useful lives. The life of each intangible asset is based either on the life of the corresponding customer contract or agreement or, in the case of a customer relationship intangible (the life of which was determined by an analysis of all available data on that business relationship), the length of time used in the discounted cash flow analysis to determine the value of the customer relationship. Among the factors we weigh, depending on the nature of the asset, are the effect of obsolescence, new technology, and competition.

For the years ended December 31, 2020, 2019 and 2018, the amortization expense on our intangibles totaled $212 million, $214 million and $219 million, respectively. Our estimated amortization expense for our intangible assets for each of the next five fiscal years (2021 – 2025) is approximately $228 million, $227 million, $222 million, $222 million, and $216 million, respectively. As of December 31, 2020, the weighted average amortization period for our intangible assets was approximately eleven years.

Revenue Recognition

The majority of our revenues are accounted for under ASC 606, *Revenue from Contracts with Customers*; however, to a limited extent, some revenues are accounted for under other guidance such as ASC 842, *Leases* or ASC 815, *Derivatives and Hedging Activities*.

Revenue from Contracts with Customers

We review our contracts with customers using the following steps to recognize revenue based on the transfer of goods or services to customers and in amounts that reflect the consideration the company expects to receive for those goods or services. The steps include: (i) identify the contract; (ii) identify the performance obligations of the contract; (iii) determine the transaction price; (iv) allocate the transaction price to the performance obligations in the contract; and then (v) recognize revenue when (or as) the performance obligation is satisfied. Each of these steps involves management judgment and an analysis of the contract's material terms and conditions.

Our customer sales contracts primarily include natural gas sales, NGL sales, crude oil sales, CO_2 sales, and transmix sales contracts, as described below. Generally, for the majority of these contracts: (i) each unit (Mcf, gallon, barrel, etc.) of commodity is a separate performance obligation, as our promise is to sell multiple distinct units of commodity at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on our right to invoice at month end for the value of commodity sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity's standalone selling price and recognized as revenue upon delivery of the commodity, which is the point in time when the customer obtains control of the commodity and our performance obligation is satisfied.

Our customer services contracts primarily include transportation service, storage service, gathering and processing service, and terminaling service contracts, as described below. Generally, for the majority of these contracts: (i) our promise is to transfer (or stand ready to transfer) a series of distinct integrated services over a period of time, which is a single performance obligation; (ii) the transaction price includes fixed and/or variable consideration, which amount is determinable at contract inception and/or at each month end based on our right to invoice at month end for the value of services provided to the customer that month; and (iii) the transaction price is recognized as revenue over the service period specified in the contract (which can be a day, including each day in a series of promised daily services, a month, a year, or other time increment, including a deficiency makeup period) as the services are rendered using a time-based (passage of time) or units-based (units of service transferred) output method for measuring the transfer of control of the services and satisfaction of our performance obligation over the service period, based on the nature of the promised service (e.g., firm or non-firm) and the terms and conditions of the contract (e.g., contracts with or without makeup rights).

Firm Services

Firm services (also called uninterruptible services) are services that are promised to be available to the customer at all times during the period(s) covered by the contract, with limited exceptions. Our firm service contracts are typically structured with take-or-pay or minimum volume provisions, which specify minimum service quantities a customer will pay for even if it chooses not to receive or use them in the specified service period (referred to as "deficiency quantities"). We typically recognize the portion of the transaction price associated with such provisions, including any deficiency quantities, as revenue depending on whether the contract prohibits the customer from making up deficiency quantities in subsequent periods, or the contract permits this practice, as follows:

- *Contracts without Makeup Rights.* If contractually the customer cannot make up deficiency quantities in future periods, our performance obligation is satisfied, and revenue associated with any deficiency quantities is generally recognized as each service period expires. Because a service period may exceed a reporting period, we determine at inception of the contract and at the beginning of each subsequent reporting period if we expect the customer to take the minimum volume associated with the service period. If we expect the customer to make up all deficiencies in the specified service period (i.e., we expect the customer to take the minimum service quantities), the minimum volume provision is deemed not substantive and we will recognize the transaction price as revenue in the specified service period as the promised units of service are transferred to the customer. Alternatively, if we expect that there will be any deficiency quantities that the customer cannot or will not make up in the specified service period (referred to as "breakage"), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over such service period in proportion to the revenue that we will recognize for actual units of service transferred to the customer in the service period. For certain take-or-pay contracts where we make the service, or a part of the service (e.g., reservation) continuously available over the service period, we typically recognize the take-or-pay amount as revenue ratably over such period based on the passage of time.

- *Contracts with Makeup Rights.* If contractually the customer can acquire the promised service in a future period and make up the deficiency quantities in such future period (the "deficiency makeup period"), we have a performance obligation to deliver those services at the customer's request (subject to contractual and/or capacity constraints) in the deficiency makeup period. At inception of the contract, and at the beginning of each subsequent reporting period, we estimate if we expect that there will be deficiency quantities that the customer will or will not make up. If we expect the customer will make up all deficiencies it is contractually entitled to, any non-refundable consideration received relating to temporary deficiencies that will be made up in the deficiency makeup period will be deferred as a contract liability, and we will recognize that amount as revenue in the deficiency makeup period when either of the following occurs: (i) the customer makes up the volumes or (ii) the likelihood that the customer will exercise its right for deficiency volumes then becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires). Alternatively, if we expect at inception of the contract, or at the beginning of any subsequent reporting period, that there will be any deficiency quantities that the customer cannot or will not make up (i.e., breakage), we will recognize the estimated breakage amount (subject to the constraint on variable consideration) as revenue ratably over the specified service periods in proportion to the revenue that we will recognize for actual units of service transferred to the customer in those service periods.

Non-Firm Services

Non-firm services (also called interruptible services) are the opposite of firm services in that such services are provided to a customer on an "as available" basis. Generally, we do not have an obligation to perform these services until we accept a customer's periodic request for service. For the majority of our non-firm service contracts, the customer will pay only for the actual quantities of services it chooses to receive or use, and we typically recognize the transaction price as revenue as those units of service are transferred to the customer in the specified service period (typically a daily or monthly period).

Contract Balances

Contract assets and contract liabilities are the result of timing differences between revenue recognition, billings and cash collections. We recognize contract assets in those instances where billing occurs subsequent to revenue recognition, and our right to invoice the customer is conditioned on something other than the passage of time. Our contract assets are substantially related to breakage revenue associated with our firm service contracts with minimum volume commitment payment obligations and contracts where we apply revenue levelization (i.e., contracts with fixed rates per volume that increase over the life of the contract for which we record revenue ratably per unit over the life of the contract based on our performance obligations that are generally unchanged over the life of the contract). Our contract liabilities are substantially related to (i) capital improvements paid for in advance by certain customers generally in our non-regulated businesses, which we subsequently recognize as revenue on a straight-line basis over the initial term of the related customer contracts; (ii) consideration received from customers for temporary deficiency quantities under minimum volume contracts that we expect will be made up in a future period, which we subsequently recognize as revenue when the customer makes up the volumes or the likelihood that the customer will exercise its right for deficiency volumes becomes remote (e.g., there is insufficient capacity to make up the volumes, the deficiency makeup period expires); and (iii) contracts with fixed rates per volume that decrease over the life of the contract where we apply revenue levelization for amounts received for our future performance obligations. We reassess amounts recorded as contract assets or liabilities upon contract modification.

Refer to Note 15 for further information.

Cost of Sales

Cost of sales primarily includes the cost to purchase energy commodities sold, including natural gas, crude oil, NGL and other refined petroleum products, adjusted for the effects of our energy commodity hedging activities, as applicable. Costs of our crude oil, gas and CO_2 producing activities, such as those in our CO_2 business segment, are not accounted for as costs of sales.

Operations and Maintenance

Operations and maintenance include costs of services and is primarily comprised of (i) operational labor costs and (ii) operations, maintenance and asset integrity, regulatory and environmental costs. Costs associated with our crude oil, gas and CO_2 producing activities included within operations and maintenance totaled $319 million, $382 million and $363 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Environmental Matters

We capitalize or expense, as appropriate, environmental expenditures. We capitalize certain environmental expenditures required to obtain rights-of-way, regulatory approvals or permitting as part of the construction of facilities we use in our business operations. We accrue and expense environmental costs that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation. We generally do not discount environmental liabilities to a net present value, and we record environmental liabilities when environmental assessments and/or remedial efforts are probable and we can reasonably estimate the costs. Generally, our accrual of these environmental liabilities coincides with either our completion of a feasibility study or our commitment to a formal plan of action. We recognize receivables for anticipated associated insurance recoveries when such recoveries are deemed to be probable. We record at estimated fair value, where appropriate, environmental liabilities assumed in a business combination.

We routinely conduct reviews of potential environmental issues and claims that could impact our assets or operations. These reviews assist us in identifying environmental issues and estimating the costs and timing of remediation efforts. We also routinely adjust our environmental liabilities to reflect changes in previous estimates. In making environmental liability estimations, we consider the material effect of environmental compliance, pending legal actions against us, and potential third-party liability claims we may have against others. Often, as the remediation evaluation and effort progresses, additional information is obtained, requiring revisions to estimated costs. These revisions are reflected in our income in the period in which they are reasonably determinable.

Leases

Lessee

We lease property including corporate and field offices and facilities, vehicles, heavy work equipment including rail cars and large trucks, tanks, office equipment and land. Our leases have remaining lease terms of one to 50 years, some of which have options to extend or terminate the lease. We determine if an arrangement is a lease at inception or upon modification. For purposes of calculating operating lease liabilities, lease terms may be deemed to include options to extend or terminate the lease when it is reasonably certain that we will exercise that option.

Beginning January 1, 2019, operating ROU assets and operating lease liabilities are recognized based on the present value of lease payments over the lease term at commencement date. Operating leases in effect prior to January 1, 2019 were recognized at the present value of the remaining payments on the remaining lease term as of January 1, 2019. Leases with variable rate adjustments, such as Consumer Price Index (CPI) adjustments, were reflected based on contractual lease payments as outlined within the lease agreement and exclude CPI adjustments. Because most of our leases do not provide an explicit rate of return, we use our incremental secured borrowing rate based on lease term information available at the commencement date of the lease in determining the present value of lease payments. We have real estate lease agreements with lease and non-lease components, which are accounted for separately, while for the remainder of our agreements we have elected the practical expedient to account for lease and non-lease components as a single lease component. For certain equipment leases, such as copiers and vehicles, we account for the leases under a portfolio method. Leases that were grandfathered under various portions of Topic 842, such as land easements, are reassessed when agreements are modified.

Refer to Note 17 for further information.

Share-based Compensation

We recognize compensation expense ratably over the vesting period of the restricted stock award based on the grant-date fair value, which is determined based on the market price of our common units on the grant date, less estimated forfeitures. Forfeiture rates are estimated based on historical forfeitures under our restricted stock award plans. Upon vesting, the restricted stock award will be paid in our Class P common shares.

Pensions and Other Postretirement Benefits

We recognize the differences between the fair value of each of our and our consolidated subsidiaries' pension and other postretirement benefit plans' assets and the benefit obligations as either assets or liabilities on our consolidated balance sheets. We record deferred plan costs and income—unrecognized losses and gains, unrecognized prior service costs and credits, and any remaining unamortized transition obligations—net of income taxes in "Accumulated other comprehensive loss," with the proportionate share associated with less than wholly owned consolidated subsidiaries allocated and included within "Noncontrolling interests," or as a regulatory asset or liability for certain of our regulated operations, until they are amortized as a component of benefit expense.

Deferred Financing Costs

We capitalize financing costs incurred with new borrowings and amortize the costs over the contractual term of the related obligations.

Redeemable Noncontrolling Interest

Redeemable noncontrolling interest represents the interest in one of our consolidated subsidiaries, ELC, that is not owned by us, which in certain limited circumstances, the partner has the right to relinquish its interest in the subsidiary and redeem its cumulative contributions, net of distributions it has received through date of redemption. Distributions paid to ELC are recorded as a reduction to the Redeemable Noncontrolling Interest balance. Net income attributable to redeemable noncontrolling interest was $54 million, $11 million and less than $1 million for the years ended December 31, 2020, 2019 and 2018, respectively, and is reported in "Net Income Attributable to Noncontrolling Interests" in our accompanying consolidated statements of income.

Noncontrolling Interests

Noncontrolling interests represents the interests in our consolidated subsidiaries that are not owned by us. In our accompanying consolidated income statements, the noncontrolling interest in the net income of our less than wholly owned consolidated subsidiaries is shown as an allocation of our consolidated net income and is presented separately as "Net Income Attributable to Noncontrolling Interests." In our accompanying consolidated balance sheets, noncontrolling interests is presented separately as "Noncontrolling interests" within "Stockholders' Equity."

Income Taxes

Income tax expense is recorded based on an estimate of the effective tax rate in effect or to be in effect during the relevant periods. Changes in tax legislation are included in the relevant computations in the period in which such changes are enacted. We do business in a number of states with differing laws concerning how income subject to each state's tax structure is measured and at what effective rate such income is taxed. Therefore, we must make estimates of how our income will be apportioned among the various states in order to arrive at an overall effective tax rate. Changes in our effective rate, including any effect on previously recorded deferred taxes, are recorded in the period in which the need for such change is identified.

Deferred income tax assets and liabilities are recognized for temporary differences between the basis of assets and liabilities for financial reporting and tax purposes. Deferred tax assets are reduced by a valuation allowance for the amount that is, more likely than not, to not be realized. While we have considered estimated future taxable income and prudent and feasible tax planning strategies in determining the amount of our valuation allowance, any change in the amount that we expect to ultimately realize will be included in income in the period in which such a determination is reached.

In determining the deferred income tax asset and liability balances attributable to our investments, we apply an accounting policy that looks through our investments. The application of this policy resulted in no deferred income taxes being provided on the difference between the book and tax basis on the non-tax-deductible goodwill portion of our investments, including KMI's investment in its wholly-owned subsidiary, KMP.

Risk Management Activities

We utilize energy commodity derivative contracts for the purpose of mitigating our risk resulting from fluctuations in the market price of commodities including crude oil, natural gas, and NGL. In addition, we enter into interest rate swap agreements for the purpose of hedging the interest rate risk associated with our debt obligations. We also enter into cross-currency swap agreements to manage our foreign currency risk with certain debt obligations, and prior to the divestitures of our Canadian assets, our net investments in foreign operations. We measure our derivative contracts at fair value and we report them on our balance sheet as either an asset or liability. For certain physical forward commodity derivatives contracts, we apply the normal purchase/normal sale exception, whereby the revenues and expenses associated with such transactions are recognized during the period when the commodities are physically delivered or received.

For qualifying accounting hedges, we formally document the relationship between the hedging instrument and the hedged item, the risk management objectives, and the methods used for assessing and testing effectiveness. When we designate a derivative contract as a cash flow accounting hedge, the entire change in fair value of the derivative that is included in the assessment of hedge effectiveness is deferred in "Accumulated other comprehensive loss" and reclassified into earnings in the period in which the hedged item affects earnings. When we designate a derivative contract as a fair value accounting hedge, the entire change in fair value of the derivative is recorded as an adjustment to the item being hedged. The gain or loss from any mismatch in the hedging relationship is recognized currently in earnings. When we designate a derivative contract as a net investment accounting hedge, the entire change in fair value of the derivative is reflected in the Foreign currency translation adjustments section of Other comprehensive (loss) income on our consolidated statements of comprehensive income.

For derivative instruments that are not designated as accounting hedges, or for which we have not elected the normal purchase/normal sales exception, changes in fair value are recognized currently in earnings.

Fair Value

The fair values of our financial instruments are separated into three broad levels (Levels 1, 2 and 3) based on our assessment of the availability of observable market data and the significance of non-observable data used to determine fair value. We assign each fair value measurement to a level corresponding to the lowest level input that is significant to the fair value measurement in its entirety. Recognized valuation techniques utilize inputs such as contractual prices, quoted market prices or rates, and discount factors. These inputs may be either readily observable or corroborated by market data.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent probable future revenues or expenses associated with certain charges and credits that will be recovered from or returned to customers through the ratemaking process. In instances where we receive recovery in tariff rates related to losses on dispositions of operating units, we record a regulatory asset for the estimated recoverable amount. We include the amounts of our regulatory assets and liabilities within "Other current assets," "Deferred charges and other assets," "Other current liabilities" and "Other long-term liabilities and deferred credits," respectively, in our accompanying consolidated balance sheets.

The following table summarizes our regulatory asset and liability balances as of December 31, 2020 and 2019:

	December 31,	
	2020	**2019**
	(In millions)	
Current regulatory assets	$ 25	$ 55
Non-current regulatory assets	231	212
Total regulatory assets(a)	$ 256	$ 267
Current regulatory liabilities	$ 26	$ 26
Non-current regulatory liabilities	169	189
Total regulatory liabilities(b)	$ 195	$ 215

(a) Regulatory assets as of December 31, 2020 include (i) $131 million of unamortized losses on disposal of assets; (ii) $49 million income tax gross up on equity AFUDC; and (iii) $76 million of other assets including amounts related to fuel tracker arrangements. Approximately $119 million of the regulatory assets, with a weighted average remaining recovery period of 14 years, are recoverable without earning a return, including the income tax gross up on equity AFUDC for which there is an offsetting deferred income tax balance for FERC rate base purposes; therefore, it does not earn a return.

(b) Regulatory liabilities as of December 31, 2020 are comprised of customer prepayments to be credited to shippers or other over-collections that are expected to be returned to shippers or netted against under-collections over time. Approximately $112 million of the $169 million classified as non-current is expected to be credited to shippers over a remaining weighted average period of 17 years, while the remaining $57 million is not subject to a defined period.

Earnings per Share

We calculate earnings per share using the two-class method. Earnings were allocated to Class P shares and participating securities based on the amount of dividends paid in the current period plus an allocation of the undistributed earnings or excess distributions over earnings to the extent that each security participates in earnings or excess distributions over earnings. Our unvested restricted stock awards, which may be restricted stock or restricted stock units issued to employees and non-employee directors and include dividend equivalent payments, do not participate in excess distributions over earnings.

The following table sets forth the allocation of net income available to shareholders of Class P shares and participating securities:

	Year Ended December 31,		
	2020	2019	2018
	(In millions, except per share amounts)		
Net Income Available to Common Stockholders	$ 119	$ 2,190	$ 1,481
Participating securities:			
Less: Net Income Allocated to Restricted stock awards(a)	(13)	(12)	(8)
Net Income Allocated to Class P Stockholders	$ 106	$ 2,178	$ 1,473
Basic Weighted Average Common Shares Outstanding	2,263	2,264	2,216
Basic Earnings Per Common Share	$ 0.05	$ 0.96	$ 0.66

(a) As of December 31, 2020, there were approximately 13 million restricted stock awards outstanding.

The following maximum number of potential common stock equivalents are antidilutive and, accordingly, are excluded from the determination of diluted earnings per share:

	Year Ended December 31,		
	2020	2019	2018
	(In millions on a weighted average basis)		
Unvested restricted stock awards	13	13	12
Convertible trust preferred securities	3	3	3
Mandatory convertible preferred stock(a)	—	—	48

(a) The holder of each convertible preferred share participated in our earnings by receiving preferred stock dividends through the mandatory conversion date of October 26, 2018 at which time our convertible preferred shares were converted to common shares.

3. Impairments and Losses and Gains on Divestitures

During the years ended December 31, 2020, 2019, and 2018, we recorded net pre-tax losses of $1,922 million, gains of $285 million and losses of $437 million, respectively, reflecting net losses on impairments of goodwill, long-lived assets, intangible and other assets and certain equity investments, and net losses and gains on divestitures of assets and equity investments. The year ended December 31, 2020 amount primarily includes pre-tax goodwill and long-lived and intangible asset impairment losses of $1,600 million and $376 million, respectively, and the year ended December 31, 2019 amount primarily includes a net pre-tax gain of $1,296 million related to the KML and U.S. Cochin Sale (see Note 4) and impairment losses of $1,014 million as further described below.

During the first quarter of 2020, the energy production and demand factors related to COVID-19 and the sharp decline in commodity prices represented a triggering event that required us to perform impairment testing on certain businesses that are sensitive to commodity prices. As a result, we performed an impairment analysis of long-lived assets within our CO_2 business segment and conducted interim tests of the recoverability of goodwill for our CO_2 and Natural Gas Pipelines Non-Regulated reporting units as of March 31, 2020, which resulted in impairments of $350 million on long-lived assets and $600 million on goodwill within our CO_2 business segment during the three months ended March 31, 2020.

Additionally, we performed our annual goodwill impairment testing as of May 31, 2020. For our Natural Gas Pipelines Non-Regulated reporting unit, while no goodwill impairment was required as of March 31, 2020, the additional market and economic indicators existing at May 31, 2020, as further described below, resulted in the recognition of a goodwill impairment for that reporting unit during the three months ended June 30, 2020.

We recognized the following non-cash pre-tax losses (gains) on impairments and divestitures on assets and equity investments during the years ended December 31, 2020, 2019 and 2018:

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Natural Gas Pipelines			
Impairment of goodwill(a)	$ 1,000	$ —	$ —
Impairments of long-lived assets(b)	—	290	636
Gains on divestitures of long-lived assets(c)	(1)	(967)	(6)
Impairments of equity investments(d)	—	650	270
Impairments of inventory	11	—	—
Products Pipelines			
Impairments of long-lived and intangible assets	21	—	—
Terminals			
Impairments of long-lived and intangible assets(e)	5	—	59
Gains on divestitures of long-lived assets(f)	(54)	(335)	(6)
Gain on sale of equity investment interests	(10)	—	—
CO_2			
Impairment of goodwill(a)	600	—	—
Impairments of long-lived assets(g)	350	74	79
Losses on divestitures of long-lived assets	—	2	—
Kinder Morgan Canada			
Loss (gain) on divestiture of long-lived assets(h)	—	2	(595)
Other losses (gains) on divestitures of long-lived assets	—	(1)	—
Pre-tax losses (gains) on divestitures and impairments, net	$ 1,922	$ (285)	$ 437

(a) 2020 amounts represent non-cash goodwill impairments associated with our Natural Gas Pipelines Non-Regulated and CO_2 reporting units (see "—*Goodwill Impairments*" below).
(b) 2019 amount represents non-cash impairments associated with certain gathering and processing assets in Oklahoma and northern Texas. 2018 amount represents non-cash impairment associated with certain gathering and processing assets in Oklahoma and a project write-off associated with the Utica Marcellus Texas pipeline.
(c) 2019 amount includes a $957 million gain related to the sale of the Cochin Pipeline system.
(d) Non-cash impairments of equity investments are included in "Earnings from equity investments" on our accompanying consolidated statements of income for the years ended December 31, 2019 and 2018. 2019 amount represents the non-cash impairment of our investment in Ruby. 2018 amount represents the non-cash impairment of our investment in Gulf LNG Holdings Group, LLC (Gulf LNG) which was driven by a ruling by an arbitration panel affecting a customer contract. Our share of earnings recognized by Gulf LNG on the respective customer contract is included in "Earnings from equity investments" on our accompanying consolidated statement of income for the year ended December 31, 2018.
(e) 2018 amount primarily relates to non-cash impairments of certain northeast terminal assets.
(f) 2020 amount includes a $55 million gain related to the sale of our Staten Island terminal. 2019 amount includes a $339 million gain related to the sale of KML.
(g) 2020, 2019 and 2018 amounts represent impairments of oil and gas properties.
(h) 2019 and 2018 amounts represent a working capital adjustment and gain on sale, respectively, associated with the TMPL Sale.

Long-lived Assets

As of March 31, 2020, for our CO_2 assets, the long-lived asset impairment test involved an assessment as to whether each asset's net book value is expected to be recovered from the estimated undiscounted future cash flows.

- To compute estimated future cash flows for our oil and gas producing properties, we used our reserve engineer specialists to estimate future oil and gas production volumes. These estimates of future oil and gas production volumes are based upon historical performance along with adjustments for expected crude oil and natural gas field development. In calculating future cash flows, management utilized estimates of commodity prices based on a March 31, 2020 NYMEX forward curve adjusted for the impact of our existing sales contracts to determine the applicable net crude oil and NGL pricing for each property. Operating expenses were determined based on estimated fixed and variable field production requirements, and capital expenditures were based on economically viable development projects.

- To compute estimated future cash flows for our CO_2 source and transportation assets, throughput and production volume forecasts were developed based on projected demand for our CO_2 services based upon management's projections of the availability of CO_2 supply and the future demand for CO_2 for use in enhanced oil recovery projects. The CO_2 pricing assumption was a function of the March 31, 2020 NYMEX forward curve adjusted for the impact of existing sales contracts to determine the applicable net CO_2 pricing. Operating expenses were determined based on estimated fixed and variable field production requirements, and capital expenditures were based on economically viable development projects.

Certain oil and gas properties failed the first step. For these assets, we used a discounted cash flow analysis to estimate fair value. We applied a 10.5% discount rate, which we believe represented the estimated weighted average cost of capital of a theoretical market participant. Based on step two of our long-lived assets impairment test, we recognized $350 million of impairments on those oil and gas producing properties where the total carrying value exceeded its total estimated fair market value as of March 31, 2020.

Our largest impairment for the year ended December 31, 2019 was a $650 million non-cash impairment to our investment in Ruby in our Natural Gas Pipelines business segment. The impairment of our investment was considered from our subordinated ownership position and driven by reduced cash flow estimates identified during the period which resulted from (i) increased Canadian gas supplies and competition from other natural gas pipelines and (ii) upcoming contract expirations. These conditions were determined to be other than temporary. We utilized a discounted cash flow analysis.

Additional impairments totaling $290 million were recognized during the year ended December 31, 2019 on long-lived assets within our Natural Gas Pipelines business segment and were driven by continued reduced drilling activity in Oklahoma and northern Texas demonstrated in the fourth quarter. Our largest impairment for the year ended December 31, 2018 was a $600 million non-cash impairment in our Natural Gas Pipelines business segment driven by reduced cash flow estimates for some of our gathering and processing assets in Oklahoma identified during the period as a result of our decision to redirect our focus to other areas of our portfolio.

Regarding our 2019 and 2018 impairments, for our long-lived assets, the reduced estimates triggered an impairment analysis, in each case, as we determined that our carrying value may no longer be recoverable. The impairment analysis for long-lived assets was based upon a two-step process as prescribed in the accounting standards. Step 1 involved comparing the undiscounted future cash flows to be derived from the asset group to the carrying value of the asset group. Based on the results of our step 1 test, we determined that the undiscounted future cash flows were less than the carrying value of the asset group. Step 2 involved using the income approach to calculate the fair value of the asset group and comparing it to the carrying value. The impairment that we recorded represented the difference between the fair and carrying values.

Goodwill Impairments

Following are the considerations made in our goodwill analysis and testing.

- Our May 31, 2020 goodwill impairment tests of the Products Pipelines, Products Pipelines Terminals, Natural Gas Pipelines Regulated and CO_2 reporting units indicated that their fair values exceeded their carrying values. The results of our impairment analyses for our Products Pipelines, Terminals and CO_2 reporting units, determined that each of the three reporting unit's fair value was in excess of carrying value by less than 10%. For the Products Pipelines and Terminals reporting units, we used the market approach with assumptions similar to those described below for the Natural Gas Pipelines Non-Regulated reporting unit. For our May 31, 2020 goodwill impairment test of the CO_2 reporting unit we used the income approach with assumptions similar to those used for its March 31, 2020 goodwill impairment test.

- In regards to our Natural Gas Pipelines Non-Regulated reporting unit, it experienced a sharp decline in customer demand for its services during the second quarter of 2020. This represented a timing lag from the initial economic decline impacts resulting from the severe downturn in the upstream energy industry, including our CO_2 business, whereby oil and gas producing companies accelerated their shut down of wells and reduced production during the second quarter which consequently adversely impacted the demand for our midstream services. In addition, continued diminished (i) current and expected future commodity pricing and (ii) peer group market capitalization values provided further indicators that an impairment of goodwill had occurred for this reporting unit during the second quarter.

  Our May 31, 2020 goodwill impairment test for the Natural Gas Pipelines Non-Regulated reporting unit utilized a weighted average of a market approach (25%) and income approach (75%) to estimate its fair value. We gave higher weighting to the income approach as we believe it was more representative of the value that would be received from a market participant.

  The market approach was based on enterprise value (EV) to estimated 2020 EBITDA multiples for a selected number of peer group midstream companies with comparable operations and economic characteristics. We estimated the median EV to EBITDA multiple to be approximately 10x without consideration of any control premium. The income approach we used to determine fair value included an analysis of estimated discounted cash flows based on 6.5 years of projections and application of an exit multiple based on management's expectations of a discount rate and exit multiple that would be applied by a theoretical market participant and for market transactions of comparable assets. We applied an approximate 8% discount rate to the undiscounted cash flow amounts which represents our estimate of the weighted average cost of capital of a theoretical market participant. The discounted cash flows included various assumptions on forecasted commodity throughput volumes and contract prices for each underlying asset within the reporting unit. The fair value based on a weighting of the market and income approaches resulted in an implied EV to 2020 EBITDA multiple valuation of approximately 11x. Management believes this is a reasonable estimate of fair value based on comparable sales transactions and the fact that it implies a reasonable control premium.

  The results of the Natural Gas Pipelines Non-Regulated reporting unit goodwill impairment analysis was a partial impairment of goodwill of approximately $1,000 million as of May 31, 2020.

- For our March 31, 2020 interim goodwill impairment test of the CO_2 reporting unit, we applied an income approach to evaluate its fair value based on the present value of its cash flows that it is expected to generate in the future. Due to the uncertainty and volatility in market conditions within its peer group as of the test date, we did not incorporate the market approach to estimate fair value as of March 31, 2020.

  In determining the fair value for our CO_2 reporting unit, we applied a 9.25% discount rate to the undiscounted cash flow amounts computed in the long-lived asset impairment analyses described above. The discount rate we used represents our estimate of the weighted average cost of capital of a theoretical market participant. The result of our goodwill analysis was a partial impairment of goodwill in our CO_2 reporting unit of approximately $600 million as of March 31, 2020.

The fair value estimates used in the long-lived asset and goodwill test were primarily based on Level 3 inputs of the fair value hierarchy.

Economic disruptions resulting from events such as COVID-19, conditions in the business environment generally, such as sustained low crude oil demand and continued low commodity prices, supply disruptions, or higher development or production costs, could result in a slowing of supply to our pipelines, terminals and other assets, which will have an adverse effect on the demand for services provided by our four business segments. Financial distress experienced by our customers or other counterparties could have an adverse impact on us in the event they are unable to pay us for the products or services we provide or otherwise fulfill their obligations to us.

As conditions warrant, we routinely evaluate our assets for potential triggering events such as those described above that could impact the fair value of certain assets or our ability to recover the carrying value of long-lived assets. Such assets include accounts receivable, equity investments, goodwill, other intangibles and property plant and equipment, including oil and gas properties and in-process construction. Depending on the nature of the asset, these evaluations require the use of significant judgments including but not limited to judgments related to customer credit worthiness, future volume expectations, current and future commodity prices, discount rates, regulatory environment, as well as general economic conditions and the related demand for products handled or transported by our assets. Although we did not identify additional triggering events during the third or fourth quarters of 2020, in the current worldwide economic and commodity price environment and to the extent conditions further deteriorate, we may identify additional triggering events that may require future evaluations of the recoverability of the carrying value of our long-lived assets, investments and goodwill which could result in further impairment charges. Because certain of our assets have been written down to fair value, or its fair value is close to carrying value, any deterioration in fair value could result in further impairments. Such non-cash impairments could have a significant effect on our results of operations, which would be recognized in the period in which the carrying value is determined to not be recoverable.

For additional information regarding changes in our goodwill, see Note 8.

4. Divestitures

Sale of U.S. Portion of Cochin Pipeline System and KML

On December 16, 2019, we closed on two cross-conditional transactions resulting in the sale of the U.S. portion of the Cochin Pipeline system and all the outstanding equity of KML, including our 70% interest, to Pembina Pipeline Corporation (Pembina) (together, the "KML and U.S. Cochin Sale"). We recognized a pre-tax net gain of $1,296 million from these transactions within "Loss (gain) on impairments and divestitures, net" on our accompanying consolidated statement of income during the year ended December 31, 2019. We received cash proceeds of $1,553 million net of a working capital adjustment, for the U.S. portion of the Cochin Pipeline system which was used to pay down debt. KML common shareholders received 0.3068 shares of Pembina common equity for each share of KML common equity. For our 70% interest in KML, we received approximately 25 million shares of Pembina common equity, with a pre-tax fair value on the transaction date of approximately $892 million. The fair market value as of December 31, 2019 of the Pembina common shares was $925 million and is reported as "Marketable securities at fair value" within our accompanying consolidated balance sheet as of December 31, 2019. Level 1 inputs in the fair value hierarchy were utilized to measure the fair value of the Pembina common shares. The Pembina common shares were sold on January 9, 2020, and we received proceeds of approximately $907 million ($764 million after tax).

Sale of Trans Mountain Pipeline System and Its Expansion Project

On August 31, 2018, KML completed the sale of the TMPL, the TMEP, the Puget Sound pipeline system for net cash consideration of C$4.43 billion (U.S.$3.4 billion), which is the contractual purchase price of C$4.5 billion net of a preliminary working capital adjustment (the "TMPL Sale"). These assets comprised our Kinder Morgan Canada business segment. We recognized a pre-tax gain from the TMPL Sale of $595 million within "Loss (gain) on impairments and divestitures, net" in our accompanying consolidated statement of income during the year ended December 31, 2018. During the first quarter of 2019, KML settled the remaining C$37 million (U.S.$28 million) of working capital adjustments which amount was substantially accrued for as of December 31, 2018.

On January 3, 2019, KML distributed the net proceeds from the TMPL Sale to its shareholders as a return of capital. Public owners of KML's restricted voting shares, reflected as noncontrolling interests by us, received approximately $0.9 billion (C$1.2 billion), and most of our approximate 70% portion of the net proceeds of $1.9 billion (C$2.5 billion) (after Canadian tax) were used to repay our outstanding commercial paper borrowings of $0.4 billion and in February 2019, to pay down approximately $1.3 billion of maturing long-term debt.

5. Income Taxes

The components of "Income Before Income Taxes" are as follows:

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
U.S.	$ 663	$ 2,482	$ 1,739
Foreign	(2)	683	767
Total Income Before Income Taxes	$ 661	$ 3,165	$ 2,506

Components of the income tax provision applicable for federal, foreign and state taxes are as follows:

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Current tax expense (benefit)			
Federal	$ (20)	$ (2)	$ (22)
State	9	10	(45)
Foreign(a)	147	201	249
Total	136	209	182
Deferred tax expense (benefit)			
Federal	440	682	425
State	49	66	55
Foreign(a)	(144)	(31)	(75)
Total	345	717	405
Total tax provision	$ 481	$ 926	$ 587

(a) Our Canadian income tax (benefit) expense was $(4) million, $165 million and $168 million for the years ended December 31, 2020, 2019 and 2018, respectively.

The difference between the statutory federal income tax rate and our effective income tax rate is summarized as follows:

	Year Ended December 31,					
	2020		2019		2018	
	(In millions, except percentages)					
Federal income tax	$ 139	21.0 %	$ 665	21.0 %	$ 526	21.0 %
Increase (decrease) as a result of:						
Taxes on foreign earnings, net of federal benefit	2	0.3 %	139	4.4 %	131	5.2 %
Net effects of noncontrolling interests	(13)	(2.0)%	(10)	(0.3)%	(65)	(2.6)%
State income tax, net of federal benefit	52	7.9 %	68	2.1 %	46	1.8 %
Dividend received deduction	(27)	(4.1)%	(39)	(1.1)%	(31)	(1.2)%
Adjustments to uncertain tax positions	3	0.5 %	(5)	(0.2)%	(47)	(1.9)%
Nondeductible goodwill	336	50.8 %	108	3.4 %	58	2.3 %
General business credit	—	— %	—	— %	(64)	(2.6)%
Federal refunds	(20)	(3.0)%	—	— %	—	— %
Other	9	1.4 %	—	— %	33	1.4 %
Total	$ 481	72.8 %	$ 926	29.3 %	$ 587	23.4 %

Deferred tax assets and liabilities result from the following:

	December 31, 2020	December 31, 2019
	(In millions)	
Deferred tax assets		
Employee benefits	$ 224	$ 208
Net operating loss carryforwards	1,484	1,261
Tax credit carryforwards	257	258
Other	242	241
Valuation allowances	(138)	(155)
Total deferred tax assets	2,069	1,813
Deferred tax liabilities		
Property, plant and equipment	414	385
Investments	1,084	529
Other	35	42
Total deferred tax liabilities	1,533	956
Net deferred tax assets	$ 536	$ 857

Deferred Tax Assets and Valuation Allowances

We have deferred tax assets of $1,484 million related to net operating loss carryovers, $257 million related to general business and foreign tax credits, and $100 million of valuation allowances related to these deferred tax assets as of December 31, 2020. As of December 31, 2019, we had deferred tax assets of $1,261 million related to net operating loss carryovers, $258 million related to general business and foreign tax credits, and $117 million of valuation allowances related to these deferred tax assets. We expect to generate taxable income and begin to utilize federal net operating loss carryforwards and tax credits in 2024.

We decreased our valuation allowances in 2020 by $17 million, primarily due to $9 million of statute expirations for state net operating losses and $8 million of currency fluctuations on foreign net operating losses.

Expiration Periods for Deferred Tax Assets: As of December 31, 2020, we have U.S. federal net operating loss carryforwards of $2.6 billion that will be carried forward indefinitely and $3.4 billion that will expire from 2021 - 2037; state losses of $3.8 billion which will expire from 2021 - 2039; and foreign losses of $83 million which will be carried forward indefinitely. We also have $240 million of general business credits which will expire from 2021 - 2039; and approximately $17 million of foreign tax credits, which will expire from 2021 - 2027. Use of a portion of our U.S. federal carryforwards is subject to the limitations provided under Sections 382 and 383 of the Internal Revenue Code as well as the separate return limitation rules of Internal Revenue Service regulations. If certain substantial changes in our ownership occur, there would be an annual limitation on the amount of carryforwards that could be utilized.

Unrecognized Tax Benefits: We recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based not only on the technical merits of the tax position based on tax law, but also the past administrative practices and precedents of the taxing authority. The tax benefits recognized in the financial statements from such a position are measured based on the largest benefit that has a greater than 50% likelihood of being realized upon ultimate resolution.

Our gross unrecognized tax benefit balances, excluding immaterial amounts of interest and penalties, were $18 million, $16 million and $34 million as of December 31, 2020, 2019 and 2018, respectively. Reductions based on settlements with taxing authorities were $0 million, $21 million and $73 million for the years ended December 31, 2020, 2019 and 2018, respectively. All of the $18 million of unrecognized tax benefits, if recognized, would affect our effective tax rate in future periods. In addition, we believe it is reasonably possible that our liability for unrecognized tax benefits will decrease by approximately $1 million during the next year to approximately $17 million, primarily due to releases from statute expirations, offset by additions for state filing positions taken in prior years.

We are subject to taxation, and have tax years open to examination for the periods 2016-2019 in the U.S., which include net operating loss utilization from earlier years, 2006-2019 in various states and 2007-2019 in various foreign jurisdictions.

6. Property, Plant and Equipment, net

Classes and Depreciation

As of December 31, 2020 and 2019, our property, plant and equipment, net consisted of the following:

	December 31,	
	2020	2019
	(In millions)	
Pipelines (Natural gas, liquids, crude oil and CO_2)	$ 20,339	$ 19,856
Equipment (Natural gas, liquids, crude oil, CO_2, and terminals)	26,142	25,791
Other(a)	5,188	5,360
Accumulated depreciation, depletion and amortization	(17,818)	(16,950)
	33,851	34,057
Land and land rights-of-way	1,403	1,356
Construction work in process	582	1,006
Property, plant and equipment, net	$ 35,836	$ 36,419

(a) Includes general plant, general structures and buildings, computer and communication equipment, intangibles, vessels, transmix products, linefill and miscellaneous property, plant and equipment.

As of December 31, 2020 and 2019, property, plant and equipment, net included $12,160 million and $12,229 million, respectively, of assets which were regulated by the FERC. Depreciation, depletion, and amortization expense charged against property, plant and equipment was $1,928 million, $2,176 million, and $2,057 million for the years ended December 31, 2020, 2019, and 2018, respectively.

Asset Retirement Obligations

As of December 31, 2020 and 2019, we recognized asset retirement obligations in the aggregate amount of $214 million and $218 million, respectively, of which $4 million were classified as current for both periods. The majority of our asset retirement obligations are associated with our CO_2 business segment, where we are required to plug and abandon oil and gas wells that have been removed from service and to remove the surface wellhead equipment and compressors.

7. Investments

Our investments primarily consist of equity investments where we hold significant influence over investee actions and for which we apply the equity method of accounting. The following table provides details on our investments as of December 31, 2020 and 2019, and our earnings (loss) from these respective investments for the years ended December 31, 2020, 2019 and 2018:

	Ownership Interest	Equity Investments		Earnings (Loss) from Equity Investments		
	December 31,	December 31,		Year Ended December 31,		
	2020	2020	2019	2020	2019	2018
		(In millions)				
Citrus Corporation	50%	$ 1,849	$ 1,856	$ 165	$ 157	$ 169
SNG	50%	1,532	1,473	129	140	141
NGPL Holdings LLC(a)	50%	803	721	116	81	66
Gulf Coast Express Pipeline LLC	34%	638	656	90	37	2
Permian Highway Pipeline	27%	632	309	—	—	—
MEP	50%	416	439	(6)	15	31
Gulf LNG(b)	50%	361	361	19	17	(61)
Products (SE) Pipe Line Corporation(c)	51%	357	348	43	58	55
Utopia Holding LLC	50%	329	335	20	20	14
EagleHawk	25%	275	285	17	17	7
Watco Companies, LLC	(d)	70	185	16	19	21
Cortez Pipeline Company	53%	25	26	24	35	36
FEP	50%	16	102	70	59	55
Ruby(e)	(f)	1	41	15	(609)	26
All others		613	622	62	55	55
Total investments		$ 7,917	$ 7,759	$ 780	$ 101	$ 617
Amortization of excess cost				$ (140)	$ (83)	$ (95)

(a) Investment in NGPL Holdings LLC (NGPL Holdings) includes a related party promissory note receivable with a principal amount of $500 million as of December 31, 2020. On October 1, 2019, NGPL Holdings issued a non-cash related party promissory note with a principal amount of $500 million as a capital distribution. The related party promissory note accrues interest at 6.75% and is payable quarterly. For the years ended December 31, 2020 and 2019, we recognized $34 million and $8 million, respectively, of interest within "Earnings from equity investments" on our accompanying consolidated statements of income.

(b) The loss from Gulf LNG for the year ended December 31, 2018 includes our share of earnings recognized due to a ruling by an arbitration panel affecting a customer contract. 2018 amount also includes a non-cash impairment charge of $270 million (pre-tax) driven by this ruling. See Note 3 for more information.

(c) Previously known as Plantation Pipe Line Company.

(d) We hold a preferred equity investment in Watco Companies, LLC (Watco). We own 50,000 Class B preferred shares and pursuant to the terms of the investment, receive priority, cumulative cash and stock distributions from the preferred shares at a rate of 3.00% per quarter. We do not hold any voting powers, but the class does provide us certain approval rights, including the right to appoint one of the members to Watco's board of managers. During the fourth quarter of 2020, we sold our Preferred A and common equity investment in Watco, and recognized a pre-tax gain of $10 million within "Other, net" on our accompanying consolidated statement of income for the year ended December 31, 2020.

(e) The loss from Ruby for the year ended December 31, 2019 amount includes a non-cash impairment charge of $650 million (pre-tax) related to our investment. See Note 3 for more information.

(f) We operate Ruby and own the common interest in Ruby, the sole owner of the Ruby Pipeline natural gas transmission system. Pembina Pipeline Corporation (Pembina) owns the remaining interest in Ruby in the form of a convertible preferred interest. If Pembina converted its preferred interest into common interest, we and Pembina would each own a 50% common interest in Ruby.

Summarized combined financial information for our significant equity investments (listed or described above) is reported below (amounts represent 100% of investee financial information):

Income Statement	Year Ended December 31, 2020	2019	2018
	(In millions)		
Revenues	$ 5,076	$ 4,906	$ 4,898
Costs and expenses	4,249	3,508	3,245
Net income	$ 827	$ 1,398	$ 1,653

Balance Sheet	December 31, 2020	2019
	(In millions)	
Current assets	$ 1,013	$ 1,195
Non-current assets	25,069	24,743
Current liabilities	1,787	2,125
Non-current liabilities	9,734	9,670
Partners'/owners' equity	14,561	14,143

8. Goodwill

Changes in the amounts of our goodwill for each of the years ended December 31, 2020 and 2019 are summarized by reporting unit as follows:

	Natural Gas Pipelines Regulated	Natural Gas Pipelines Non-Regulated	CO_2	Products Pipelines	Products Pipelines Terminals	Terminals	Total
				(In millions)			
Gross goodwill	$ 15,892	$ 5,812	$ 1,528	$ 2,125	$ 221	$ 1,573	$ 27,151
Accumulated impairment losses	(1,643)	(1,597)	—	(1,197)	(70)	(679)	(5,186)
December 31, 2018	14,249	4,215	1,528	928	151	894	21,965
Divestitures(a)	—	(422)	—	—	—	(92)	(514)
Transfer(b)	—	(450)	—	450	—	—	—
December 31, 2019	14,249	3,343	1,528	1,378	151	802	21,451
Impairments(c)	—	(1,000)	(600)	—	—	—	(1,600)
Transfer	—	—	—	—	—	—	—
December 31, 2020	14,249	2,343	928	1,378	151	802	19,851
Gross goodwill	15,892	4,940	1,528	2,575	221	1,481	26,637
Accumulated impairment losses	(1,643)	(2,597)	(600)	(1,197)	(70)	(679)	(6,786)
December 31, 2020	$ 14,249	$ 2,343	$ 928	$ 1,378	$ 151	$ 802	$ 19,851

(a) 2019 includes $514 million related to the KML and U.S. Cochin Sale. See Note 4 for more information.

(b) Effective January 1, 2019, for segment reporting purposes, certain assets were transferred among our business segments which resulted in the transfer of goodwill from the Natural Gas Pipelines Non-Regulated reporting unit to the Products Pipelines reporting unit. See Note 16 for more information.

(c) See Note 3 "*Impairments and Losses and Gains on Divestitures—Goodwill Impairments*" for further information regarding our goodwill impairments.

9. Debt

The following table provides detail on the principal amount of our outstanding debt balances:

	December 31, 2020	December 31, 2019
	(In millions, unless otherwise stated)	
Credit facility and commercial paper borrowings(a)	$ —	$ 37
Corporate senior notes(b)		
6.85%, due February 2020	—	700
6.50%, due April 2020	—	535
5.30%, due September 2020	—	600
6.50%, due September 2020	—	349
5.00%, due February 2021	750	750
3.50%, due March 2021(c)	750	750
5.80%, due March 2021	400	400
5.00%, due October 2021	500	500
4.15%, due March 2022	375	375
1.50%, due March 2022(d)	917	841
3.95%, due September 2022	1,000	1,000
3.15%, due January 2023	1,000	1,000
Floating rate, due January 2023(e)	250	250
3.45%, due February 2023	625	625
3.50%, due September 2023	600	600
5.625%, due November 2023	750	750
4.15%, due February 2024	650	650
4.30%, due May 2024	600	600
4.25%, due September 2024	650	650
4.30%, due June 2025	1,500	1,500
6.70%, due February 2027	7	7
2.25%, due March 2027(d)	611	561
6.67%, due November 2027	7	7
4.30%, due March 2028	1,250	1,250
7.25%, due March 2028	32	32
6.95%, due June 2028	31	31
8.05%, due October 2030	234	234
2.00%, due February 2031(f)	750	—
7.40%, due March 2031	300	300
7.80%, due August 2031	537	537
7.75%, due January 2032	1,005	1,005
7.75%, due March 2032	300	300
7.30%, due August 2033	500	500
5.30%, due December 2034	750	750
5.80%, due March 2035	500	500
7.75%, due October 2035	1	1
6.40%, due January 2036	36	36
6.50%, due February 2037	400	400
7.42%, due February 2037	47	47
6.95%, due January 2038	1,175	1,175
6.50%, due September 2039	600	600
6.55%, due September 2040	400	400
7.50%, due November 2040	375	375
6.375%, due March 2041	600	600
5.625%, due September 2041	375	375
5.00%, due August 2042	625	625
4.70%, due November 2042	475	475
5.00%, due March 2043	700	700
5.50%, due March 2044	750	750
5.40%, due September 2044	550	550
5.55%, due June 2045	1,750	1,750
5.05%, due February 2046	800	800

(continued)	December 31, 2020	December 31, 2019
5.20%, due March 2048	750	750
3.25%, due August 2050(f)	500	—
7.45%, due March 2098	26	26
TGP senior notes(b)		
7.00%, due March 2027	300	300
7.00%, due October 2028	400	400
2.90%, due March 2030(g)	1,000	—
8.375%, due June 2032	240	240
7.625%, due April 2037	300	300
EPNG senior notes(b)		
8.625%, due January 2022	260	260
7.50%, due November 2026	200	200
8.375%, due June 2032	300	300
CIG senior notes(b)		
4.15%, due August 2026	375	375
6.85%, due June 2037	100	100
EPC Building, LLC, promissory note, 3.967%, due January 2020 through December 2035	380	395
Trust I Preferred Securities, 4.75%, due March 2028(h)	221	221
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock, due August 2057(i)	—	100
Other miscellaneous debt(j)	254	258
Total debt – KMI and Subsidiaries	33,396	33,360
Less: Current portion of debt(k)	2,558	2,477
Total long-term debt – KMI and Subsidiaries(l)	$ 30,838	$ 30,883

(a) See "—Current portion of debt" below for further details regarding the outstanding credit facility and commercial paper borrowings.

(b) Notes provide for the redemption at any time at a price equal to 100% of the principal amount of the notes plus accrued interest to the redemption date plus a make whole premium and are subject to a number of restrictions and covenants. The most restrictive of these include limitations on the incurrence of liens and limitations on sale-leaseback transactions.

(c) On January 4, 2021, we repaid our $750 million senior corporate notes.

(d) Consists of senior notes denominated in Euros that have been converted to U.S. dollars and are respectively reported above at the December 31, 2020 exchange rate of 1.2216 U.S. dollars per Euro and at the December 31, 2019 exchange rate of 1.1213 U.S. dollars per Euro. As of December 31, 2020 and 2019, the cumulative changes in the exchange rate of U.S. dollars per Euro since issuance had resulted in increases to our debt balance of $102 million and $26 million, respectively, related to the 1.50% series and increases of $68 million and $18 million, respectively, related to the 2.25% series. The cumulative increase in debt due to the changes in exchange rates is offset by a corresponding change in the value of cross-currency swaps reflected in "Deferred charges and other assets" and "Other long-term liabilities and deferred credits" on our accompanying consolidated balance sheets. At the time of issuance, we entered into foreign currency contracts associated with these senior notes, effectively converting these Euro-denominated senior notes to U.S. dollars (see Note 14 "*Risk Management—Foreign Currency Risk Management*").

(e) During the year ended December 31, 2019, we entered into a floating-to-fixed interest rate swap agreement which was designated as a cash flow hedge.

(f) On August 5, 2020, we issued in a registered offering two series of senior notes consisting of $750 million aggregate principal amount of 2.00% senior notes due 2031 and $500 million aggregate principal amount of 3.25% senior notes due 2050 and received combined net proceeds of $1,226 million.

(g) On February 24, 2020, TGP issued in a private placement $1,000 million aggregate principal amount of its 2.90% senior notes due 2030 and received net proceeds of $991 million.

(h) Capital Trust I (Trust I), is a 100%-owned business trust that as of December 31, 2020, had 4.4 million of 4.75% trust convertible preferred securities outstanding (referred to as the Trust I Preferred Securities). Trust I exists for the sole purpose of issuing preferred securities and investing the proceeds in 4.75% convertible subordinated debentures, which are due 2028. Trust I's sole source of income is interest earned on these debentures. This interest income is used to pay distributions on the preferred securities. We provide a full and unconditional guarantee of the Trust I Preferred Securities. There are no significant restrictions from these securities on our ability to obtain funds from our subsidiaries by distribution, dividend or loan. The Trust I Preferred Securities are non-voting (except in limited circumstances), pay quarterly distributions at an annual rate of 4.75% and carry a liquidation value of $50 per security plus accrued and unpaid distributions. The Trust I Preferred Securities outstanding as of December 31, 2020 are convertible at any time prior to the close of business on March 31, 2028, at the option of the holder, into the following mixed consideration: (i) 0.7197 of a share of our Class P common stock; and (ii) $25.18 in cash without interest. We have the right to redeem these Trust I Preferred Securities at any time.

(i) As of December 31, 2019, KMGP had outstanding 100,000 shares of its $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock due 2057, which was redeemed including accrued dividends on January 15, 2020.

(j) Includes finance lease obligations with monthly installments. The lease terms expire between 2024 and 2061.

(k) Amounts include KMI outstanding credit facility borrowings, commercial paper borrowings and other debt maturing within 12 months. See "—Current Portion of Debt" below.

(l) Excludes our "Debt fair value adjustments" which, as of December 31, 2020 and 2019, increased our combined debt balances by $1,293 million and $1,032 million, respectively. In addition to all unamortized debt discount/premium amounts, debt issuance costs and purchase accounting on our debt balances, our debt fair value adjustments also include amounts associated with the offsetting entry for hedged debt and any unamortized portion of proceeds received from the early termination of interest rate swap agreements. For further information about our debt fair value adjustments, see "—Debt Fair Value Adjustments" below.

Current Portion of Debt

The following table details the components of our "Current portion of debt" reported on our consolidated balance sheets:

	December 31, 2020	December 31, 2019
	(In millions, unless otherwise stated)	
$4 billion credit facility due November 16, 2023	$ —	$ —
Commercial paper notes(a)	—	37
Current portion of senior notes		
6.85%, due February 2020	—	700
6.50%, due April 2020	—	535
5.30%, due September 2020	—	600
6.50%, due September 2020	—	349
5.00%, due February 2021	750	—
3.50%, due March 2021(b)	750	—
5.80%, due March 2021	400	—
5.00%, due October 2021	500	—
Trust I Preferred Securities, 4.75% due March 2028(c)	111	111
KMGP, $1,000 Liquidation Value Series A Fixed-to-Floating Rate Term Cumulative Preferred Stock, due August 2057(d)	—	100
Current portion of other debt	47	45
Total current portion of debt	$ 2,558	$ 2,477

(a) Weighted average interest rates on borrowings outstanding as of December 31, 2019 was 1.90%.
(b) On January 4, 2021, we repaid our $750 million senior corporate notes.
(c) Reflects the portion of cash consideration payable if all the outstanding securities as of the end of the reporting period were converted by the holders.
(d) In December 2019, we notified the holder of our intent to redeem these securities. As our notification was irrevocable, the outstanding balance was classified as current in our accompanying balance sheet as of December 31, 2019. We redeemed these securities including accrued dividends on January 15, 2020.

We and substantially all of our wholly owned domestic subsidiaries are a party to a cross guarantee agreement whereby each party to the agreement unconditionally guarantees, jointly and severally, the payment of specified indebtedness of each other party to the agreement.

Credit Facility and Restrictive Covenants

As of December 31, 2020, we had borrowing capacity of approximately $3.9 billion under our $4 billion revolving credit facility. We also continue to maintain a $4 billion commercial paper program through the private placement of short-term notes. The notes mature up to 270 days from the date of issue and are not redeemable or subject to voluntary prepayment by us prior to maturity. The notes are sold at par value less a discount representing an interest factor or if interest bearing, at par. Borrowings under our revolving credit facility can be used for working capital and other general corporate purposes and as a backup to our commercial paper program. Borrowings under our commercial paper program reduce the borrowings allowed under our credit facility.

Depending on the type of loan request, our credit facility borrowings under our credit facility bear interest at either (i) LIBOR adjusted for a eurocurrency funding reserve plus an applicable margin ranging from 1.000% to 2.000% per annum based on our credit ratings or (ii) the greatest of (1) the Federal Funds Rate plus 0.5%; (2) the Prime Rate; or (3) LIBOR for a one-month eurodollar loan adjusted for a eurocurrency funding reserve, plus 1%, plus, in each case, an applicable margin ranging from 0.100% to 1.000% per annum based on our credit rating. Standby fees for the unused portion of the credit facility will be calculated at a rate ranging from 0.100% to 0.300%.

Our credit facility contains financial and various other covenants that apply to us and our subsidiaries and are common in such agreements, including a maximum ratio of Consolidated Net Indebtedness to Consolidated EBITDA (as defined in the credit facility) of 5.50 to 1.00, for any four-fiscal-quarter period. Other negative covenants include restrictions on our and certain of our subsidiaries' ability to incur debt, grant liens, make fundamental changes or engage in certain transactions with affiliates, or in the case of certain material subsidiaries, permit restrictions on dividends, distributions or making or prepayments of loans to us or any guarantor. Our credit facility also restricts our ability to make certain restricted payments if an event of default (as defined in the credit facility) has occurred and is continuing or would occur and be continuing.

As of December 31, 2020, we had no borrowings outstanding under our credit facility, no borrowings outstanding under our commercial paper program and $82 million in letters of credit. Our availability under this facility as of December 31, 2020 was approximately $3.9 billion. As of December 31, 2020, we were in compliance with all required covenants.

Maturities of Debt

The scheduled maturities of the outstanding debt balances, excluding debt fair value adjustments as of December 31, 2020, are summarized as follows:

Year	**Total**
	(In millions)
2021	$ 2,558
2022	2,575
2023	3,250
2024	1,925
2025	1,566
Thereafter	21,522
Total	$ 33,396

Debt Fair Value Adjustments

The following table summarizes the "Debt fair value adjustments" included on our accompanying consolidated balance sheets:

	December 31,	
	2020	**2019**
	(In millions)	
Purchase accounting debt fair value adjustments	$ 546	$ 599
Carrying value adjustment to hedged debt	702	359
Unamortized portion of proceeds received from the early termination of interest rate swap agreements(a)	240	257
Unamortized debt discounts, net	(76)	(67)
Unamortized debt issuance costs	(119)	(116)
Total debt fair value adjustments	$ 1,293	$ 1,032

(a) As of December 31, 2020, the weighted-average amortization period of the unamortized premium from the termination of interest rate swaps was approximately 14 years.

Fair Value of Financial Instruments

The carrying value and estimated fair value of our outstanding debt balances is disclosed below:

	December 31, 2020		December 31, 2019	
	Carrying value	Estimated fair value	Carrying value	Estimated fair value
	(In millions)			
Total debt	$ 34,689	$ 39,622	$ 34,392	$ 38,016

We used Level 2 input values to measure the estimated fair value of our outstanding debt balance as of both December 31, 2020 and 2019.

Interest Rates, Interest Rate Swaps and Contingent Debt

The weighted average interest rate on all of our borrowings was 4.86% during 2020 and 5.27% during 2019. Information on our interest rate swaps is contained in Note 14. For information about our contingent debt agreements, see Note 13 "*Commitments and Contingent Liabilities—Contingent Debt*").

10. Share-based Compensation and Employee Benefits

Share-based Compensation

Class P Shares

Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors

We have a Kinder Morgan, Inc. Amended and Restated Stock Compensation Plan for Non-Employee Directors, in which our eligible non-employee directors participate. The plan recognizes that the compensation paid to each eligible non-employee director is fixed by our board of directors, generally annually, and that the compensation is payable in cash. Pursuant to the plan, in lieu of receiving some or all of the cash compensation, each eligible non-employee director may elect to receive shares of Class P common stock. Each election will be generally at or around the first board of directors meeting in January of each calendar year and will be effective for the entire calendar year. An eligible director may make a new election each calendar year. The total number of shares of Class P common stock authorized under the plan is 250,000. During 2020, 2019 and 2018, we made restricted Class P common stock grants to our non-employee directors of 14,570, 23,100 and 25,800, respectively. These grants were valued at time of issuance at $0.3 million, $0.4 million and $0.5 million, respectively. All of the restricted stock awards made to non-employee directors vest during a 6-month period.

Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan

The Kinder Morgan, Inc. 2015 Amended and Restated Stock Incentive Plan is an equity awards plan available to eligible employees. The total number of shares of Class P common stock authorized under the plan is 33,000,000. The following table sets forth a summary of activity and related balances of our restricted stock awards excluding that issued to non-employee directors:

	Shares	Weighted Average Grant Date Fair Value per Share
	(In thousands, except per share amounts)	
Outstanding at December 31, 2019	12,414	$ 20.07
Granted	4,532	15.10
Vested	(4,035)	21.71
Forfeited	(229)	18.99
Outstanding at December 31, 2020	12,682	$ 17.79

The following table sets forth additional information related to our restricted stock awards excluding that issued to non-employee directors:

	Year Ended December 31,		
	2020	2019	2018
	(In millions, except per share amounts)		
Weighted average grant date fair value per share	$ 15.10	$ 20.46	$ 17.73
Intrinsic value of awards vested during the year	59	87	42

Restricted stock awards made to employees have vesting periods ranging from 1 year up to 10 years. Following is a summary of the future vesting of our outstanding restricted stock awards:

Year	Vesting of Restricted Shares
	(In thousands)
2021	4,216
2022	3,051
2023	4,775
2024	127
2025	513
Total Outstanding	12,682

During 2020, 2019 and 2018, we recorded $73 million, $62 million and $63 million, respectively, in expense related to restricted stock awards and capitalized approximately $11 million, $12 million and $13 million, respectively. We allocate labor and benefit costs to joint ventures that we operate in accordance with our partnership agreements. At December 31, 2020, unrecognized restricted stock awards compensation costs, less estimated forfeitures, was approximately $102 million with a weighted average remaining amortization period of 2.08 years.

Pension and Other Postretirement Benefit (OPEB) Plans

Savings Plan

We maintain a defined contribution plan covering eligible U.S. employees. We contribute 5% of eligible compensation for most of the plan participants. Certain collectively bargained participants receive Company contributions in accordance with collective bargaining agreements. A participant becomes fully vested in Company contributions after two years and may take a distribution upon termination of employment or retirement. The total cost for our savings plan was approximately $53 million, $50 million, and $48 million for the years ended December 31, 2020, 2019 and 2018, respectively.

Pension Plans

Our pension plans are defined benefit plans that cover substantially all of our U.S. employees and provide benefits under a cash balance formula. A participant in the cash balance formula accrues benefits through contribution credits based on a combination of age and years of service, multiplied by eligible compensation. Interest is also credited to the participant’s plan account. A participant becomes fully vested in the plan after three years and may take a lump sum or annuity distribution upon termination of employment or retirement. Certain collectively bargained and grandfathered employees accrue benefits through career pay or final pay formulas.

OPEB Plans

We and certain of our subsidiaries provide OPEB benefits, including medical benefits for closed groups of retired employees and certain grandfathered employees and their dependents, and limited postretirement life insurance benefits for retired employees. These plans provide a fixed subsidy to post-age 65 Medicare eligible participants to purchase coverage through a retiree Medicare exchange. Medical benefits under these OPEB plans may be subject to deductibles, co-payment provisions, dollar caps and other limitations on the amount of employer costs, and we reserve the right to change these benefits.

Benefit Obligation, Plan Assets and Funded Status. The following table provides information about our pension and OPEB plans as of and for each of the years ended December 31, 2020 and 2019:

	Pension Benefits		OPEB	
	2020	2019	2020	2019
	(In millions)			
Change in benefit obligation:				
Benefit obligation at beginning of period	$ 2,696	$ 2,566	$ 333	$ 339
Service cost	59	53	1	1
Interest cost	71	96	8	12
Actuarial loss (gain)	198	159	(17)	10
Benefits paid	(180)	(178)	(29)	(32)
Participant contributions	—	—	2	2
Medicare Part D subsidy receipts	—	—	1	1
Benefit obligation at end of period	2,844	2,696	299	333
Change in plan assets:				
Fair value of plan assets at beginning of period	2,076	1,864	333	306
Actual return on plan assets	178	330	47	49
Employer contributions	125	60	7	7
Participant contributions	—	—	2	2
Medicare Part D subsidy receipts	—	—	1	1
Benefits paid	(180)	(178)	(29)	(32)
Fair value of plan assets at end of period	2,199	2,076	361	333
Funded status - net (liability) asset at December 31,	$ (645)	$ (620)	$ 62	$ —

The 2020 net actuarial loss for the pension plans was primarily due to a decrease in the weighted average discount rate used to determine the benefit obligation as of December 31, 2020. The 2020 net actuarial gain for the OPEB plans was primarily due to changes in the claims cost and trend assumptions, partially offset by a decrease in the weighted average discount rate used to determine the benefit obligations as of December 31, 2020. The 2019 net actuarial loss for the pension plans was primarily due to a decrease in the weighted average discount rate used to determine the benefit obligations as of December 31, 2019, partially offset by a change in the mortality assumption. The 2019 net actuarial loss for the OPEB plans was primarily due to a decrease in the weighted average discount rate used to determine the benefit obligations as of December 31, 2019, partially offset by a change in the claims cost and mortality assumptions.

Components of Funded Status. The following table details the amounts recognized in our balance sheets at December 31, 2020 and 2019 related to our pension and OPEB plans:

	Pension Benefits		OPEB	
	2020	2019	2020	2019
	(In millions)			
Non-current benefit asset(a)	$ —	$ —	$ 269	$ 231
Current benefit liability	—	—	(19)	(18)
Non-current benefit liability	(645)	(620)	(188)	(213)
Funded status - net (liability) asset at December 31,	$ (645)	$ (620)	$ 62	$ —

(a) 2020 and 2019 OPEB amounts include $46 million and $39 million, respectively, of non-current benefit assets related to a plan we sponsor which is associated with employee services provided to an unconsolidated joint venture, and for which we have recorded an offsetting related party deferred credit.

Components of Accumulated Other Comprehensive (Loss) Income. The following table details the amounts of pre-tax accumulated other comprehensive (loss) income at December 31, 2020 and 2019 related to our pension and OPEB plans which are included on our accompanying consolidated balance sheets:

	Pension Benefits		OPEB	
	2020	**2019**	**2020**	**2019**
	(In millions)			
Unrecognized net actuarial (loss) gain	$ (674)	$ (557)	$ 153	$ 123
Unrecognized prior service (cost) credit	(2)	(3)	9	12
Accumulated other comprehensive (loss) income	$ (676)	$ (560)	$ 162	$ 135

Our accumulated benefit obligation for our pension plans was $2,804 million and $2,659 million at December 31, 2020 and 2019, respectively.

Our accumulated postretirement benefit obligation for our OPEB plans, whose accumulated postretirement benefit obligations exceeded the fair value of plan assets, was $255 million and $288 million at December 31, 2020 and 2019, respectively. The fair value of these plans' assets was approximately $48 million and $57 million at December 31, 2020 and 2019, respectively.

Plan Assets. The investment policies and strategies are established by our plan's fiduciary committee for the assets of each of the pension and OPEB plans, which are responsible for investment decisions and management oversight of the plans. The stated philosophy of the fiduciary committee is to manage these assets in a manner consistent with the purpose for which the plans were established and the time frame over which the plans' obligations need to be met. The objectives of the investment management program are to (i) meet or exceed plan actuarial earnings assumptions over the long term and (ii) provide a reasonable return on assets within established risk tolerance guidelines and to maintain the liquidity needs of the plans with the goal of paying benefit and expense obligations when due. In seeking to meet these objectives, the fiduciary committee recognizes that prudent investing requires taking reasonable risks in order to raise the likelihood of achieving the targeted investment returns. In order to reduce portfolio risk and volatility, the fiduciary committee has adopted a strategy of using multiple asset classes.

As of December 31, 2020, the allowable range for asset allocations in effect for our pension plan were 31% to 55% equity, 37% to 57% fixed income, 0% to 5% cash, 0% to 2% alternative investments and 0% to 10% company securities (KMI Class P common stock and/or debt securities). As of December 31, 2020, the allowable range for asset allocations in effect for our OPEB plans were 46% to 68% equity, 25% to 50% fixed income and 0% to 22% cash.

Below are the details of our pension and OPEB plan assets by class and a description of the valuation methodologies used for assets measured at fair value.

- Level 1 assets' fair values are based on quoted market prices for the instruments in actively traded markets. Included in this level are cash, equities and exchange traded mutual funds. These investments are valued at the closing price reported on the active market on which the individual securities are traded.

- Level 2 assets' fair values are primarily based on pricing data representative of quoted prices for similar assets in active markets (or identical assets in less active markets). Included in this level are short-term investment funds, fixed income securities and derivatives. Short-term investment funds are valued at amortized cost, which approximates fair value. The fixed income securities' fair values are primarily based on an evaluated price which is based on a compilation of primarily observable market information or a broker quote in a non-active market. Derivatives are exchange-traded through clearinghouses and are valued based on these prices.

- Plan assets with fair values that are based on the net asset value per share, or its equivalent (NAV), as reported by the issuers are determined based on the fair value of the underlying securities as of the valuation date and include common/collective trust funds, private investment funds and limited partnerships. The plan assets measured at NAV are not categorized within the fair value hierarchy described above, but are separately identified in the following tables.

Listed below are the fair values of our pension and OPEB plans' assets that are recorded at fair value by class and categorized by fair value measurement used at December 31, 2020 and 2019:

	Pension Assets					
	2020			2019		
	Level 1	Level 2	Total	Level 1	Level 2	Total
	(In millions)					
Measured within fair value hierarchy						
Short-term investment funds	$ —	$ 77	$ 77	$ —	$ 50	$ 50
Equities(a)	249	—	249	296	—	296
Fixed income securities(b)	—	425	425	—	405	405
Derivatives	—	11	11	—	12	12
Subtotal	$ 249	$ 513	762	$ 296	$ 467	763
Measured at NAV(c)						
Common/collective trusts(d)			1,184			1,069
Private investment funds(e)			208			200
Private limited partnerships(f)			45			44
Subtotal			1,437			1,313
Total plan assets fair value			$ 2,199			$ 2,076

(a) Plan assets include $83 million and $129 million of KMI Class P common stock for 2020 and 2019, respectively.
(b) Plan assets include $1 million of KMI debt securities for both 2020 and 2019.
(c) Plan assets which used NAV as a practical expedient to measure fair value.
(d) Common/collective trust funds were invested in approximately 29% fixed income and 71% equity in 2020 and 32% fixed income and 68% equity in 2019.
(e) Private investment funds were invested in approximately 71% fixed income and 29% equity in 2020 and 73% fixed income and 27% equity in 2019.
(f) Includes assets invested in real estate, venture and buyout funds.

	OPEB Assets					
	2020			2019		
	Level 1	Level 2	Total	Level 1	Level 2	Total
	(In millions)					
Measured within fair value hierarchy						
Cash	$ —	$ —	$ —	$ 1	$ —	$ 1
Short-term investment funds	—	5	5	—	5	5
Equities	—	—	—	25	—	25
Fixed income securities	—	—	—	—	17	17
Mutual funds(a)	—	—	—	11	—	11
Subtotal	$ —	$ 5	5	$ 37	$ 22	59
Measured at NAV(b)						
Common/collective trusts(c)			356			274
Subtotal			356			274
Total plan assets fair value			$ 361			$ 333

(a) Includes mutual funds which are invested in equities and fixed income securities.
(b) Plan assets which used NAV as a practical expedient to measure fair value.
(c) Common/collective trust funds were invested in approximately 65% equity and 35% fixed income securities for 2020 and 64% equity and 36% fixed income securities for 2019.

Expected Payment of Future Benefits and Employer Contributions. As of December 31, 2020, we expect to make the following benefit payments under our plans:

Fiscal year	Pension Benefits	OPEB(a)
	(In millions)	
2021	$ 239	$ 30
2022	238	28
2023	225	27
2024	219	25
2025	211	23
2026 - 2030	902	94

(a) Includes a reduction of approximately $1 million in each of the years 2021 through 2025 and approximately $6 million in aggregate for the period 2026 - 2030 for an expected subsidy related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

In 2021, we expect to contribute approximately $56 million to our pension plans and $7 million, net of anticipated subsidies, to our OPEB plans.

Actuarial Assumptions and Sensitivity Analysis. Benefit obligations and net benefit cost are based on actuarial estimates and assumptions. The following table details the weighted-average actuarial assumptions used in determining our benefit obligation and net benefit costs of our pension and OPEB plans for 2020, 2019 and 2018:

	Pension Benefits			OPEB		
	2020	2019	2018	2020	2019	2018
	(In millions)					
Assumptions related to benefit obligations:						
Discount rate	2.27 %	3.17 %	4.26 %	2.08 %	3.03 %	4.16 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	n/a	n/a	n/a
Interest crediting rate	2.57 %	3.71 %	3.90 %	n/a	n/a	n/a
Assumptions related to benefit costs:						
Discount rate for benefit obligations	3.17 %	4.26 %	3.56 %	3.03 %	4.16 %	3.48 %
Discount rate for interest on benefit obligations	2.71 %	3.89 %	3.13 %	2.63 %	3.83 %	3.08 %
Discount rate for service cost	3.24 %	4.28 %	3.56 %	3.48 %	4.51 %	3.82 %
Discount rate for interest on service cost	2.80 %	3.93 %	3.14 %	3.39 %	4.46 %	3.76 %
Expected return on plan assets(a)	6.75 %	7.25 %	7.25 %	6.50 %	6.50 %	7.08 %
Rate of compensation increase	3.50 %	3.50 %	3.50 %	n/a	n/a	n/a
Interest crediting rate	3.71 %	3.90 %	2.71 %	n/a	n/a	n/a

(a) The expected return on plan assets listed in the table above is a pre-tax rate of return based on our targeted portfolio of investments. For the OPEB assets subject to unrelated business income taxes (UBIT), we utilize an after-tax expected return on plan assets to determine our benefit costs, which is based on UBIT rates of 27%, 27% and 21% for 2020, 2019 and 2018, respectively.

We utilize a full yield curve approach in the estimation of the service and interest cost components of net periodic benefit cost (credit) for our retirement benefit plans by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to their underlying projected cash flows. The expected long-term rates of return on plan assets were determined by combining a review of the historical returns realized within the portfolio, the investment strategy included in the plans' investment policy, and capital market projections for the asset classes in which the portfolio is invested and the target weightings of each asset class.

Actuarial estimates for our OPEB plans assume an annual increase in the per capita cost of covered health care benefits; the initial annual rate of increase is 5.80% which gradually decreases to 4.50% by the year 2038.

Components of Net Benefit Cost and Other Amounts Recognized in Other Comprehensive Income. For each of the years ended December 31, the components of net benefit cost and other amounts recognized in pre-tax other comprehensive income related to our pension and OPEB plans are as follows:

	Pension Benefits			OPEB		
	2020	2019	2018	2020	2019	2018
	(In millions)					
Components of net benefit cost (credit):						
Service cost	$ 59	$ 53	$ 52	$ 1	$ 1	$ 1
Interest cost	71	96	84	8	12	12
Expected return on assets	(137)	(129)	(149)	(16)	(16)	(20)
Amortization of prior service cost (credit)	1	—	—	(5)	(4)	(4)
Amortization of net actuarial loss (gain)	40	54	40	(13)	(11)	(6)
Net benefit cost (credit)	34	74	27	(25)	(18)	(17)
Other changes in plan assets and benefit obligations recognized in other comprehensive (income) loss:						
Net loss (gain) arising during period	157	(42)	105	(43)	(17)	(32)
Amortization or settlement recognition of net actuarial (loss) gain	(40)	(54)	(87)	13	11	3
Amortization of prior service (cost) credit	(1)	—	(1)	3	2	3
Total recognized in total other comprehensive loss (income)(a)	116	(96)	17	(27)	(4)	(26)
Total recognized in net benefit cost (credit) and other comprehensive loss (income)	$ 150	$ (22)	$ 44	$ (52)	$ (22)	$ (43)

(a) Excludes $2 million for the year ended December 31, 2020 associated with other plans.

Multiemployer Plans

We participate in several multi-employer pension plans for the benefit of employees who are union members. We do not administer these plans and contribute to them in accordance with the provisions of negotiated labor contracts. Other benefits include a self-insured health and welfare insurance plan and an employee health plan where employees may contribute for their dependents' health care costs. Amounts charged to expense for these plans were approximately $6 million for the year ended December 31, 2020 and $8 million for each of the years ended December 31, 2019 and 2018. We consider the overall multi-employer pension plan liability exposure to be immaterial in relation to the value of its total consolidated assets and net income.

11. Stockholders' Equity

Mandatory Convertible Preferred Stock

As of October 26, 2018, all of our issued and outstanding 1,600,000 shares of 9.75% Series A mandatory convertible preferred stock, with a liquidating preference of $1,000 per share were converted into common stock either at the option of the holders before or automatically on October 26, 2018. Based on the market price of our common stock at the time of conversion, our Series A Preferred Shares converted into approximately 58 million common shares. We paid all dividends on our mandatory convertible preferred stock in cash.

Common Equity

As of December 31, 2020, our common equity consisted of our Class P common stock.

On July 19, 2017, our board of directors approved a $2 billion common share buy-back program that began in December 2017. During the years ended December 31, 2020, 2019 and 2018, we repurchased approximately 4 million, 0.1 million and 15 million, respectively, of our Class P shares for approximately $50 million, $2 million and $273 million, respectively. Since December 2017, in total, we have repurchased approximately 32 million of our Class P shares under the program at an average price of approximately $17.71 per share for approximately $575 million.

On December 19, 2014, we entered into an equity distribution agreement authorizing us to issue and sell through or to the managers party thereto, as sales agents and/or principals, shares of our Class P common stock having an aggregate offering of up to $5.0 billion from time to time during the term of this agreement. During the years ended December 31, 2020, 2019 and 2018 we did not issue any Class P common stock under this agreement.

KMI Common Stock Dividends

Holders of our common stock participate in any dividend declared by our board of directors, subject to the rights of the holders of any outstanding preferred stock. The following table provides information about our per share dividends:

	Year Ended December 31,		
	2020	**2019**	**2018**
Per common share cash dividend declared for the period	$ 1.05	$ 1.00	$ 0.80
Per common share cash dividend paid in the period	1.0375	0.95	0.725

On January 20, 2021, our board of directors declared a cash dividend of $0.2625 per common share for the quarterly period ended December 31, 2020, which is payable on February 16, 2021 to shareholders of record as of February 1, 2021.

Accumulated Other Comprehensive Loss

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Loss

Cumulative revenues, expenses, gains and losses that under GAAP are included within our comprehensive income but excluded from our earnings are reported as “Accumulated other comprehensive loss” within “Stockholders’ Equity” in our consolidated balance sheets. Changes in the components of our “Accumulated other comprehensive loss” not including non-controlling interests are summarized as follows:

	Net unrealized gains/(losses) on cash flow hedge derivatives	Foreign currency translation adjustments	Pension and other postretirement liability adjustments	Total Accumulated other comprehensive loss
	(In millions)			
Balance at December 31, 2017	$ (27)	$ (189)	$ (325)	$ (541)
Other comprehensive gain (loss) before reclassifications	111	(89)	(31)	(9)
Losses reclassified from accumulated other comprehensive loss(a)	84	223	22	329
Impact of adoption of ASU 2018-02 (see below)	(4)	(36)	(69)	(109)
Net current-period change in accumulated other comprehensive (loss) income	191	98	(78)	211
Balance at December 31, 2018	164	(91)	(403)	(330)
Other comprehensive (loss) gain before reclassifications	(177)	—	77	(100)
Losses reclassified from accumulated other comprehensive loss(a)	6	91	—	97
Net current-period change in accumulated other comprehensive income (loss)	(171)	91	77	(3)
Balance at December 31, 2019	(7)	—	(326)	(333)
Other comprehensive gain (loss) before reclassifications	249	—	(68)	181
Gains reclassified from accumulated other comprehensive loss	(255)	—	—	(255)
Net current-period change in accumulated other comprehensive loss	(6)	—	(68)	(74)
Balance at December 31, 2020	$ (13)	$ —	$ (394)	$ (407)

(a) Amounts for foreign currency translation adjustments and pension and other postretirement liability adjustments reflect the deferred losses recognized in income during the year ended December 31, 2018 related to the TMPL Sale. Amount for foreign currency translation adjustments reflect the deferred losses recognized in income during the year ended December 31, 2019 related to the sale of KML.

Noncontrolling Interests

KML Distributions

In accordance with its dividend policy, KML, our former indirect subsidiary, paid dividends during the years ended December 31, 2019 and 2018, on its restricted voting shares to the public valued at $17 million and $52 million, respectively, of which $17 million and $38 million, respectively, was paid in cash. The remaining value of $14 million for the year ended December 31, 2018, respectively, was paid in 1,092,791 KML restricted voting shares. KML also paid dividends to the public on its preferred shares of $22 million and $21 million for the years ended December 31, 2019 and 2018.

On January 3, 2019, KML distributed approximately $0.9 billion of the net proceeds from the TMPL Sale to its public held restricted voting shareholders as a return of capital.

Adoption of Accounting Pronouncements

On January 1, 2018, we adopted ASU No. 2017-05, "*Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets*." This ASU clarifies the scope and application of ASC 610-20 on contracts for the sale or transfer of nonfinancial assets and in substance nonfinancial assets to noncustomers, including partial sales. This ASU also clarifies that the derecognition of all businesses is in the scope of ASC 810 and defines an "in substance nonfinancial asset." We utilized the modified retrospective method to adopt the provisions of this ASU, which required us to apply the new standard to (i) all new contracts entered into after January 1, 2018, and (ii) to contracts that were not completed contracts as of January 1, 2018 through a cumulative adjustment to our "Accumulated deficit" balance. The cumulative effect of the adoption of this ASU was a $66 million, net of income taxes, adjustment to our beginning "Accumulated deficit" balance as presented in our consolidated statement of stockholders' equity for the year ended December 31, 2018. This ASU also required us to classify EIG Global Energy Partners' (EIG) cumulative contribution to ELC as mezzanine equity, which we have included as "Redeemable Noncontrolling Interest" on our consolidated balance sheets as of December 31, 2020 and 2019, as EIG has the right to redeem their interests for cash under certain conditions.

On January 1, 2018, we adopted ASU No. 2018-02, "*Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income*." Our accounting policy for the release of stranded tax effects in accumulated other comprehensive income is on an aggregate portfolio basis. This ASU permits companies to reclassify the income tax effects of the 2017 Tax Reform on items within accumulated other comprehensive income to retained earnings. The FASB refers to these amounts as "stranded tax effects." Only the stranded tax effects resulting from the 2017 Tax Reform are eligible for reclassification. The adoption of this ASU resulted in a $109 million reclassification adjustment of stranded income tax effects from "Accumulated other comprehensive loss" to "Accumulated deficit" on our consolidated statement of stockholders' equity for the year ended December 31, 2018.

12. Related Party Transactions

Affiliate Balances

We have transactions with affiliates which consist of (i) unconsolidated affiliates in which we hold an investment accounted for under the equity method of accounting (see Note 7 for additional information related to these investments); and (ii) external partners of our joint ventures we consolidate, and for periods prior to the sale of KML, our proportional method joint ventures, for which we include our proportionate share of balances and activity in our financial statements.

The following tables summarize our affiliate balance sheet balances and income statement activity, other than amounts reported within our "Investments" balances and "Earnings from equity investments" activity:

	December 31,	
	2020	2019
	(In millions)	
Balance sheet location		
Accounts receivable	$ 41	$ 38
Other current assets	6	—
Deferred charges and other assets	109	86
	$ 156	$ 124
Current portion of debt	$ 6	$ 6
Accounts payable	25	23
Other current liabilities	4	3
Long-term debt	154	157
Other long-term liabilities and deferred credits	48	41
	$ 237	$ 230

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Income statement location			
Revenues	$ 206	$ 269	$ 265
Operating Costs, Expenses and Other			
Costs of sales	$ 116	$ 75	$ 63
Other operating expenses	119	132	91

13. Commitments and Contingent Liabilities

Rights-Of-Way (ROW) Obligations

Our ROW obligations primarily consist of non-lease agreements that existed at the time of Topic 842 adoption, at which time we elected a practical expedient which allowed us to continue our historical treatment. Our future minimum rental commitments related to our ROW obligations were $172 million as of December 31, 2020.

Contingent Debt

Our contingent debt disclosures pertain to certain types of guarantees or indemnifications we have made and cover certain types of guarantees included within debt agreements, even if the likelihood of requiring our performance under such guarantee is remote.

As of December 31, 2020 and 2019, our contingent debt obligations, as well as our obligations with respect to related letters of credit, totaled $217 million and $330 million, respectively. December 31, 2020 and 2019 amounts are represented by our proportional share of the debt obligations of three equity investees. Under such guarantees we are severally liable for our percentage ownership share of these equity investees' debt issued in the event of their non-performance. The contingent debt obligations balances as of December 31, 2020 and 2019 included $122 million and $128 million, respectively, for 100% guaranteed debt obligations for a subsidiary of our equity investee, Cortez Pipeline Company.

Guarantees and Indemnifications

Our equity investee, SNG, has $300 million of debt maturing in June 2021 that it anticipates refinancing. We currently have a commitment to SNG to fund $150 million if SNG is unable to refinance or otherwise satisfy its obligation.

We are involved in joint ventures and other ownership arrangements that sometimes require financial and performance guarantees. In a financial guarantee, we are obligated to make payments if the guaranteed party fails to make payments under, or violates the terms of, the financial arrangement. In a performance guarantee, we provide assurance that the guaranteed party will execute on the terms of the contract. If they do not, we are required to perform on their behalf. We also periodically provide indemnification arrangements related to assets or businesses we have sold. These arrangements include, but are not limited to, indemnifications for income taxes, the resolution of existing disputes and environmental matters.

While many of these agreements may specify a maximum potential exposure, or a specified duration to the indemnification obligation, there are also circumstances where the amount and duration are unlimited. Currently, we are not subject to any material requirements to perform under quantifiable arrangements other than as described above. We are unable to estimate a maximum exposure for our other guarantee and indemnification agreements that do not provide for limits on the amount of future payments due to the uncertainty of these exposures.

See Note 18 for a description of matters that we have identified as contingencies requiring accrual of liabilities and/or disclosure, including any such matters arising under guarantee or indemnification agreements.

14. Risk Management

Certain of our business activities expose us to risks associated with unfavorable changes in the market price of natural gas, NGL and crude oil. We also have exposure to interest rate and foreign currency risk as a result of the issuance of our debt obligations. Pursuant to our management's approved risk management policy, we use derivative contracts to hedge or reduce our exposure to some of these risks.

Energy Commodity Price Risk Management

As of December 31, 2020, we had the following outstanding commodity forward contracts to hedge our forecasted energy commodity purchases and sales:

	Net open position long/(short)
Derivatives designated as hedging contracts	
Crude oil fixed price	(20.4) MMBbl
Crude oil basis	(2.2) MMBbl
Natural gas fixed price	(30.1) Bcf
Natural gas basis	(20.0) Bcf
NGL fixed price	(1.1) MMBbl
Derivatives not designated as hedging contracts	
Crude oil fixed price	(5.6) MMBbl
Crude oil basis	(6.8) MMBbl
Natural gas fixed price	(6.7) Bcf
Natural gas basis	(5.5) Bcf
NGL fixed price	(1.0) MMBbl

As of December 31, 2020, the maximum length of time over which we have hedged, for accounting purposes, our exposure to the variability in future cash flows associated with energy commodity price risk is through December 2024.

Interest Rate Risk Management

We utilize interest rate derivatives to hedge our exposure to both changes in the fair value of our fixed rate debt instruments and variability in expected future cash flows attributable to variable interest rate payments. The following table summarizes our outstanding interest rate contracts as of December 31, 2020:

	Notional amount	Accounting treatment	Maximum term
	(In millions)		
Derivatives designated as hedging instruments			
Fixed-to-variable interest rate contracts(a)	$ 7,625	Fair value hedge	March 2035
Variable-to-fixed interest rate contracts	250	Cash flow hedge	January 2023
Derivatives not designated as hedging instruments			
Variable-to-fixed interest rate contracts	2,500	Mark-to-Market	December 2021

(a) The principal amount of hedged senior notes consisted of $900 million included in "Current portion of debt" and $6,725 million included in "Long-term debt" on our accompanying consolidated balance sheet.

Foreign Currency Risk Management

We utilize foreign currency derivatives to hedge our exposure to variability in foreign exchange rates. The following table summarizes our outstanding foreign currency contracts as of December 31, 2020:

	Notional amount	Accounting treatment	Maximum term
	(In millions)		
Derivatives designated as hedging instruments			
EUR-to-USD cross currency swap contracts(a)	$ 1,358	Cash flow hedge	March 2027

(a) These swaps eliminate the foreign currency risk associated with all of our Euro-denominated debt.

Impact of Derivative Contracts on Our Consolidated Financial Statements

The following table summarizes the fair values of our derivative contracts included in our accompanying consolidated balance sheets:

Fair Value of Derivative Contracts

		Derivatives Asset		Derivatives Liability	
		December 31,		December 31,	
		2020	2019	2020	2019
	Location	Fair value		Fair value	
		(In millions)			
Derivatives designated as hedging instruments					
Energy commodity derivative contracts	Fair value of derivative contracts/ (Other current liabilities)	$ 42	$ 31	$ (33)	$ (43)
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	33	17	(8)	(8)
Subtotal		75	48	(41)	(51)
Interest rate contracts	Fair value of derivative contracts/ (Other current liabilities)	119	45	(3)	—
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	575	313	(7)	(1)
Subtotal		694	358	(10)	(1)
Foreign currency contracts	Fair value of derivative contracts/ (Other current liabilities)	—	—	(6)	(6)
	Deferred charges and other assets/ (Other long-term liabilities and deferred credits)	138	46	—	—
Subtotal		138	46	(6)	(6)
Total		907	452	(57)	(58)
Derivatives not designated as hedging instruments					
Energy commodity derivative contracts	Fair value of derivative contracts/ (Other current liabilities)	24	8	(21)	(7)
Total derivatives		$ 931	$ 460	$ (78)	$ (65)

The following two tables summarize the fair value measurements of our derivative contracts based on the three levels established by the ASC. The tables also identify the impact of derivative contracts which we have elected to present on our accompanying consolidated balance sheets on a gross basis that are eligible for netting under master netting agreements.

	Balance sheet asset fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral held(b)	Net amount
				(In millions)			
As of December 31, 2020							
Energy commodity derivative contracts(a)	$ 6	$ 93	$ —	$ 99	$ (35)	$ —	$ 64
Interest rate contracts	—	694	—	694	(2)	—	692
Foreign currency contracts	—	138	—	138	(6)	—	132
As of December 31, 2019							
Energy commodity derivative contracts(a)	$ 19	$ 37	$ —	$ 56	$ (19)	$ (21)	$ 16
Interest rate contracts	—	358	—	358	—	—	358
Foreign currency contracts	—	46	—	46	(6)	—	40

	Balance sheet liability fair value measurements by level						
	Level 1	Level 2	Level 3	Gross amount	Contracts available for netting	Cash collateral posted(b)	Net amount
				(In millions)			
As of December 31, 2020							
Energy commodity derivative contracts(a)	$ (7)	$ (56)	$ —	$ (63)	$ 35	$ (8)	$ (36)
Interest rate contracts	—	(10)	—	(10)	2	—	(8)
Foreign currency contracts	—	(6)	—	(6)	6	—	—
As of December 31, 2019							
Energy commodity derivative contracts(a)	(3)	(55)	—	(58)	19	—	(39)
Interest rate contracts	—	(1)	—	(1)	—	—	(1)
Foreign currency contracts	—	(6)	—	(6)	6	—	—

(a) Level 1 consists primarily of NYMEX natural gas futures. Level 2 consists primarily of OTC WTI swaps, NGL swaps and crude oil basis swaps.
(b) Any cash collateral paid or received is reflected in this table, but only to the extent that it represents variation margins. Any amount associated with derivative prepayments or initial margins that are not influenced by the derivative asset or liability amounts or those that are determined solely on their volumetric notional amounts are excluded from this table.

The following tables summarize the pre-tax impact of our derivative contracts in our accompanying consolidated statements of income and comprehensive income:

Derivatives in fair value hedging relationships	Location	Gain/(loss) recognized in income on derivatives and related hedged item		
		Year Ended December 31,		
		2020	2019	2018
		(In millions)		
Interest rate contracts	Interest, net	$ 335	$ 340	$ (122)
Hedged fixed rate debt(a)	Interest, net	$ (343)	$ (353)	$ 113

(a) As of December 31, 2020, the cumulative amount of fair value hedging adjustments to our hedged fixed rate debt was an increase of $702 million included in "Debt fair value adjustments" on our accompanying consolidated balance sheets.

Derivatives in cash flow hedging relationships	Gain/(loss) recognized in OCI on derivative(a)			Location	Gain/(loss) reclassified from Accumulated OCI into income(b)		
	Year Ended December 31,				Year Ended December 31,		
	2020	2019	2018		2020	2019	2018
	(In millions)				(In millions)		
Energy commodity derivative contracts	$ 240	$ (168)	$ 201	Revenues—Commodity sales	$ 222	$ 16	$ (59)
				Costs of sales	(14)	5	21
Interest rate contracts(c)	(8)	(1)	3	Earnings from equity investments(c)	—	2	(4)
Foreign currency contracts	92	(60)	(59)	Other, net	125	(31)	(67)
Total	$ 324	$ (229)	$ 145	Total	$ 333	$ (8)	$ (109)

(a) We expect to reclassify an approximate $9 million gain associated with cash flow hedge price risk management activities included in our accumulated other comprehensive loss balance as of December 31, 2020 into earnings during the next twelve months (when the associated forecasted transactions are also expected to impact earnings); however, actual amounts reclassified into earnings could vary materially as a result of changes in market prices.
(b) During the year ended December 31, 2019, we recognized a $12 million gain associated with a write-down of hedged inventory. During the year ended December 31, 2018, we recognized a $3 million loss as a result of our equity investment's forecasted transactions being probable of not occurring and a $21 million gain associated with a write-down of hedged inventory. All other amounts reclassified were

the result of the hedged forecasted transactions actually affecting earnings (i.e., when the forecasted sales and purchases actually occurred).

(c) Amounts represent our share of an equity investee's accumulated other comprehensive income (loss).

Derivatives in net investment hedging relationships	Gain/(loss) recognized in OCI on derivative			Location	Gain/(loss) reclassified from Accumulated OCI into income(a)		
	Year Ended December 31,				Year Ended December 31,		
	2020	2019	2018		2020	2019	2018
	(In millions)				(In millions)		
Foreign currency contracts	$ —	$ (8)	$ 91	Loss (gain) on impairments and divestitures, net	$ —	$ 83	$ 26
Total	$ —	$ (8)	$ 91	Total	$ —	$ 83	$ 26

(a) During the year ended December 31, 2019, we recognized an $83 million gain related to the KML and U.S. Cochin Sale. During the year ended December 31, 2018, we recognized a $26 million gain related to the TMPL Sale. See Note 4.

Derivatives not designated as accounting hedges	Location	Gain/(Loss) recognized in income on derivatives		
		Year Ended December 31,		
		2020	2019	2018
		(In millions)		
Energy commodity derivative contracts	Revenues—Commodity sales	$ (1)	$ 33	$ (9)
	Costs of sales	25	(7)	2
	Earnings from equity investments(b)	—	3	—
Total(a)		$ 24	$ 29	$ (7)

(a) The years ended December 31, 2020, 2019 and 2018 include approximate gains of $11 million and losses of $8 million and $4 million, respectively, associated with natural gas, crude and NGL derivative contract settlements.

(b) Amounts represent our share of an equity investee's income (loss).

Credit Risks

In conjunction with certain derivative contracts, we are required to provide collateral to our counterparties, which may include posting letters of credit or placing cash in margin accounts. As of December 31, 2020 and 2019, we had no outstanding letters of credit supporting our commodity price risk management program. As of December 31, 2020 and 2019, we had cash margins of $3 million and $15 million, respectively, posted by our counterparties with us as collateral and reported within "Other current liabilities" on our accompanying consolidated balance sheets. The balance at December 31, 2020 represents the net of our initial margin requirements of $11 million, offset by counterparty variation margin requirements of $8 million. We also use industry standard commercial agreements that allow for the netting of exposures associated with transactions executed under a single commercial agreement. Additionally, we generally utilize master netting agreements to offset credit exposure across multiple commercial agreements with a single counterparty.

We also have agreements with certain counterparties to our derivative contracts that contain provisions requiring the posting of additional collateral upon a decrease in our credit rating. As of December 31, 2020, based on our current mark-to-market positions and posted collateral, we estimate that if our credit rating were downgraded one notch, we would not be required to post additional collateral. If we were downgraded two notches, we estimate that we would be required to post $6 million of additional collateral.

15. Revenue Recognition

Nature of Revenue by Segment

Natural Gas Pipelines Segment

We provide various types of natural gas transportation and storage services, natural gas and NGL sales contracts, and various types of gathering and processing services for producers, including receiving, compressing, transporting and re-delivering quantities of natural gas and/or NGLs made available to us by producers to a specified delivery location.

Natural Gas Transportation and Storage Contracts

The natural gas we receive under our transportation and storage contracts remains under the control of our customers. Under firm service contracts, the customer generally pays a two-part transaction price that includes (i) a fixed fee reserving the right to transport or store natural gas in our facilities up to contractually specified capacity levels (referred to as "reservation") and (ii) a fee-based per-unit rate for quantities of natural gas actually transported or injected into/withdrawn from storage. In our firm service contracts we generally promise to provide a single integrated service each day over the life of the contract, which is fundamentally a stand-ready obligation to provide services up to the customer's reservation capacity prescribed in the contract. Our customers have a take-or-pay payment obligation with respect to the fixed reservation fee component, regardless of the quantities they actually transport or store. In other cases, generally described as interruptible service, there is no fixed fee associated with these transportation and storage services because the customer accepts the possibility that service may be interrupted at our discretion in order to serve customers who have firm service contracts. We do not have an obligation to perform under interruptible customer arrangements until we accept and schedule the customer's request for periodic service. The customer pays a transaction price on a fee-based per-unit rate for the quantities actually transported or injected into/withdrawn from storage.

Natural Gas and NGL Sales Contracts

Our sales and purchases of natural gas and NGL are primarily accounted for on a gross basis as natural gas sales or product sales, as applicable, and cost of sales. These customer contracts generally provide for the customer to nominate a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Gathering and Processing Contracts

We provide various types of gathering and processing services for producers, including receiving, processing, compressing, transporting and re-delivering quantities of natural gas made available to us by producers to a specified delivery location. This integrated service can be firm if subject to a minimum volume commitment or acreage dedication or non-firm when offered on an as requested, non-guaranteed basis. In our gathering contracts we generally promise to provide the contracted integrated services each day over the life of the contract. The customer pays a transaction price typically based on a per-unit rate for the quantities actually gathered and/or processed, including amounts attributable to deficiency quantities associated with minimum volume contracts.

Products Pipelines Segment

We provide crude oil and refined petroleum transportation and storage services on a firm or non-firm basis. For our firm transportation service, we typically promise to transport on a stand-ready basis the customer's minimum volume commitment amount. The customer is obligated to pay for its volume commitment amount, regardless of whether or not it flows volumes into our pipeline. The customer pays a transaction price typically based on a per-unit rate for quantities transported, including amounts attributable to deficiency quantities. Our firm storage service generally includes a fixed monthly fee for the portion of storage capacity reserved by the customer and a per-unit rate for actual quantities injected into/withdrawn from storage. The customer is obligated to pay the fixed monthly reservation fee, regardless of whether or not it uses our storage facility (i.e., take-or-pay payment obligation). Non-firm transportation and storage service is provided to our customers when and to the extent we determine the requested capacity is available in our pipeline system and/or terminal storage facility. The customer typically pays a per-unit rate for actual quantities of product injected into/withdrawn from storage and/or transported.

We sell transmix, crude oil or other commodity products. The customer's contracts generally include a specified quantity of commodity products to be delivered and sold to the customers at specified delivery points. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Terminals Segment

We provide various types of liquid tank and bulk terminal services. These services are generally comprised of inbound, storage and outbound handling of customer products.

Liquids Tank Services

Firm Storage and Handling Contracts: We have liquids tank storage and handling service contracts that include a promised tank storage capacity provision and prepaid volume throughput of the stored product. In these contracts, we have a stand-ready obligation to perform this contracted service each day over the life of the contract. The customer pays a transaction price typically in the form of a fixed monthly charge and is obligated to pay whether or not it uses the storage capacity and throughput service (i.e., a take-or-pay payment obligation). These contracts generally include a per-unit rate for any quantities we handle at the request of the customer in excess of the prepaid volume throughput amount and also typically include per-unit rates for additional, ancillary services that may be periodically requested by the customer.

Firm Handling Contracts: For our firm handling service contracts, we typically promise to handle on a stand-ready basis throughput volumes up to the customer's minimum volume commitment amount. The customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it used the handling service. The customer pays a transaction price typically based on a per-unit rate for volumes handled, including amounts attributable to deficiency quantities.

Bulk Services

Our bulk storage and handling contracts generally include inbound handling of our customers' dry bulk material product (e.g. petcoke, metals, ores) into our storage facility and outbound handling of these products from our storage facility. These services are provided on both a firm and non-firm basis. In our firm bulk storage and handling contracts, we are committed to handle and store on a stand-ready basis the minimum throughput quantity of bulk materials contracted by the customer. In some cases, the customer is obligated to pay for its minimum volume commitment amount, regardless of whether or not it uses the storage and handling service. The customer pays a transaction price typically based on a per-unit rate for quantities handled, including amounts attributable to deficiency quantities. For non-firm storage and handling services, the customer pays a transaction price typically based on a per-unit rate for quantities handled on an as requested, non-guaranteed basis.

CO_2 Segment

Our crude oil, NGL, CO_2 and natural gas production customer sales contracts typically include a specified quantity and quality of commodity product to be delivered and sold to the customer at a specified delivery point. The customer pays a transaction price typically based on a market indexed per-unit rate for the quantities sold.

Kinder Morgan Canada Segment

On August 31, 2018, the assets comprising the Kinder Morgan Canada business segment were sold; therefore, this segment will not have revenues on a prospective basis (see Note 4). Prior to the sale of these assets, we provided crude oil and refined petroleum transportation services generally as described above for non-firm, interruptible transportation services in our Products Pipelines business segment. The TMPL regulated tariff was designed to provide revenues sufficient to recover the costs of providing transportation services to shippers, including a return on invested capital. TMPL's revenue was adjusted according to terms prescribed in our toll settlement with shippers as approved by the National Energy Board (NEB). Differences between transportation revenue recognized pursuant to our toll settlement and actual toll receipts were recognized as regulatory assets or liabilities and settled through future tolls.

Disaggregation of Revenues

The following tables present our revenues disaggregated by revenue source and type of revenue for each revenue source:

	Year Ended December 31, 2020					
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Corporate and Eliminations	Total
	(In millions)					
Revenues from contracts with customers(a)						
Services						
Firm services(b)	$ 3,345	$ 271	$ 756	$ 1	$ (3)	$ 4,370
Fee-based services	714	905	395	42	—	2,056
Total services	4,059	1,176	1,151	43	(3)	6,426
Commodity sales						
Natural gas sales	2,038	—	—	1	(7)	2,032
Product sales	562	358	14	735	(30)	1,639
Total commodity sales	2,600	358	14	736	(37)	3,671
Total revenues from contracts with customers	6,659	1,534	1,165	779	(40)	10,097
Other revenues(c)						
Leasing services	466	166	557	47	—	1,236
Derivatives adjustments on commodity sales	18	—	—	203	—	221
Other	116	21	—	9	—	146
Total other revenues	600	187	557	259	—	1,603
Total revenues	$ 7,259	$ 1,721	$ 1,722	$ 1,038	$ (40)	$ 11,700

	Year Ended December 31, 2019					
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Corporate and Eliminations	Total
	(In millions)					
Revenues from contracts with customers(a)						
Services						
Firm services(b)	$ 3,549	$ 319	$ 1,012	$ 1	$ (4)	$ 4,877
Fee-based services	780	1,016	560	60	—	2,416
Total services	4,329	1,335	1,572	61	(4)	7,293
Commodity sales						
Natural gas sales	2,603	—	—	1	(9)	2,595
Product sales	805	289	20	1,111	(33)	2,192
Total commodity sales	3,408	289	20	1,112	(42)	4,787
Total revenues from contracts with customers	7,737	1,624	1,592	1,173	(46)	12,080
Other revenues(c)						
Leasing services	273	182	442	54	—	951
Derivatives adjustments on commodity sales	70	—	—	(21)	—	49
Other	90	25	—	13	1	129
Total other revenues	433	207	442	46	1	1,129
Total revenues	$ 8,170	$ 1,831	$ 2,034	$ 1,219	$ (45)	$ 13,209

	Year Ended December 31, 2018						
	Natural Gas Pipelines	Products Pipelines	Terminals	CO_2	Kinder Morgan Canada(d)	Corporate and Eliminations	Total
				(In millions)			
Revenues from contracts with customers(a)							
Services							
Firm services(b)	$ 3,387	$ 376	$ 983	$ 2	$ —	$ (2)	$ 4,746
Fee-based services	692	956	584	67	167	—	2,466
Total services	4,079	1,332	1,567	69	167	(2)	7,212
Commodity sales							
Natural gas sales	3,327	—	—	2	—	(11)	3,318
Product sales	1,190	393	20	1,222	—	(37)	2,788
Total commodity sales	4,517	393	20	1,224	—	(48)	6,106
Total revenues from contracts with customers	8,596	1,725	1,587	1,293	167	(50)	13,318
Other revenues(c)							
Leasing services	220	158	440	48	2	—	868
Derivatives adjustments on commodity sales	(25)	—	—	(108)	—	—	(133)
Other	64	4	—	22	1	—	91
Total other revenues	259	162	440	(38)	3	—	826
Total revenues	$ 8,855	$ 1,887	$ 2,027	$ 1,255	$ 170	$ (50)	$ 14,144

(a) Differences between the revenue classifications presented on the consolidated statements of income and the categories for the disaggregated revenues by type of revenue above are primarily attributable to revenues reflected in the "Other revenues" category above (see note (c)).
(b) Includes non-cancellable firm service customer contracts with take-or-pay or minimum volume commitment elements, including those contracts where both the price and quantity amount are fixed. Excludes service contracts with indexed-based pricing, which along with revenues from other customer service contracts are reported as Fee-based services.
(c) Amounts recognized as revenue under guidance prescribed in Topics of the ASC other than in Topic 606 were primarily from leases and derivative contracts. See Note 14 for additional information related to our derivative contracts.
(d) On August 31, 2018, the assets comprising the Kinder Morgan Canada business segment were sold; therefore, this segment does not have results of operations on a prospective basis (see Note 4).

Contract Balances

As of December 31, 2020 and 2019, our contract asset balances were $20 million and $27 million, respectively. Of the contract asset balance at December 31, 2019, $24 million was transferred to accounts receivable during the year ended December 31. 2020. As of December 31, 2020 and 2019, our contract liability balances were $239 million and $232 million, respectively. Of the contract liability balance at December 31, 2019, $65 million was recognized as revenue during the year ended December 31, 2020.

Revenue Allocated to Remaining Performance Obligations

The following table presents our estimated revenue allocated to remaining performance obligations for contracted revenue that has not yet been recognized, representing our "contractually committed" revenue as of December 31, 2020 that we will invoice or transfer from contract liabilities and recognize in future periods:

Year		Estimated Revenue
		(In millions)
2021	$	4,281
2022		3,500
2023		2,824
2024		2,439
2025		2,073
Thereafter		13,286
Total	$	28,403

Our contractually committed revenue, for purposes of the tabular presentation above, is generally limited to service or commodity sale customer contracts which have fixed pricing and fixed volume terms and conditions, generally including contracts with take-or-pay or minimum volume commitment payment obligations. Our contractually committed revenue amounts generally exclude, based on the following practical expedient that we elected to apply, remaining performance obligations for contracts with index-based pricing or variable volume attributes in which such variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

16. Reportable Segments

Our reportable business segments are:

- Natural Gas Pipelines—the ownership and operation of (i) major interstate and intrastate natural gas pipeline and storage systems; (ii) natural gas gathering systems and natural gas processing and treating facilities; (iii) NGL fractionation facilities and transportation systems; and (iv) LNG regasification, liquefaction and storage facilities;

- Products Pipelines—the ownership and operation of refined petroleum products, crude oil and condensate pipelines that primarily deliver, among other products, gasoline, diesel and jet fuel, crude oil and condensate to various markets, plus the ownership and/or operation of associated product terminals and petroleum pipeline transmix facilities;

- Terminals—the ownership and/or operation of (i) liquids and bulk terminal facilities located throughout the U.S. and portions of Canada (prior to the sale of KML in December 2019) that store and handle various commodities including gasoline, diesel fuel, chemicals, ethanol, metals and petroleum coke; and (ii) Jones Act-qualified tankers;

- CO_2—(i) the production, transportation and marketing of CO_2 to oil fields that use CO_2 as a flooding medium to increase recovery and production of crude oil from mature oil fields; (ii) ownership interests in and/or operation of oil fields and gasoline processing plants in West Texas; and (iii) the ownership and operation of a crude oil pipeline system in West Texas; and

- Kinder Morgan Canada (prior to August 31, 2018)—the ownership and operation of the Trans Mountain pipeline system that transports crude oil and refined petroleum products from Edmonton, Alberta, Canada to marketing terminals and refineries in British Columbia, Canada and the state of Washington. As a result of the TMPL Sale, this segment does not have results of operations on a prospective basis.

We evaluate performance principally based on each segment's EBDA, which excludes general and administrative expenses and corporate charges, interest expense, net, and income tax expense. Our reportable segments are strategic business units that offer different products and services, and they are structured based on how our chief operating decision makers organize their operations for optimal performance and resource allocation. Each segment is managed separately because each segment involves different products and services and marketing strategies.

We consider each period's earnings before all non-cash DD&A expenses to be an important measure of business segment performance for our reporting segments. We account for intersegment sales at market prices, while we account for asset transfers at book value.

During 2020, 2019 and 2018, we did not have revenues from any single external customer that exceeded 10% of our consolidated revenues.

Financial information by segment follows:

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Revenues			
Natural Gas Pipelines			
Revenues from external customers	$ 7,222	$ 8,128	$ 8,807
Intersegment revenues	37	42	48
Products Pipelines	1,721	1,831	1,887
Terminals			
Revenues from external customers	1,719	2,031	2,025
Intersegment revenues	3	3	2
CO_2	1,038	1,219	1,255
Kinder Morgan Canada	—	—	170
Corporate and intersegment eliminations	(40)	(45)	(50)
Total consolidated revenues	$ 11,700	$ 13,209	$ 14,144

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Operating expenses(a)			
Natural Gas Pipelines	$ 3,457	$ 4,213	$ 5,218
Products Pipelines	779	684	748
Terminals	762	888	823
CO_2	404	496	453
Kinder Morgan Canada	—	—	72
Corporate and intersegment eliminations	(4)	(1)	(26)
Total consolidated operating expenses	$ 5,398	$ 6,280	$ 7,288

	Year Ended December 31,		
	2020	2019	2018
		(In millions)	
Other expense (income)(b)			
Natural Gas Pipelines	$ 1,009	$ (680)	$ 629
Products Pipelines	21	—	(2)
Terminals	(50)	(342)	54
CO_2	950	77	79
Kinder Morgan Canada	—	2	(596)
Corporate	—	(2)	—
Total consolidated other expense (income)	$ 1,930	$ (945)	$ 164

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
DD&A			
Natural Gas Pipelines	$ 1,062	$ 1,005	$ 955
Products Pipelines	347	338	326
Terminals	438	494	489
CO_2	291	548	473
Kinder Morgan Canada	—	—	29
Corporate	26	26	25
Total consolidated DD&A	$ 2,164	$ 2,411	$ 2,297

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Earnings (loss) from equity investments and amortization of excess cost of equity investments, including loss on impairments of equity investments			
Natural Gas Pipelines	$ 551	$ (101)	$ 410
Products Pipelines	45	63	56
Terminals	22	23	22
CO_2	22	33	34
Total consolidated equity earnings	$ 640	$ 18	$ 522

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Other, net-income (expense)			
Natural Gas Pipelines	$ 11	$ 53	$ 39
Products Pipelines	1	6	2
Terminals	13	(5)	3
Kinder Morgan Canada	—	—	26
Corporate	31	21	37
Total consolidated other, net-income (expense)	$ 56	$ 75	$ 107

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Segment EBDA(c)			
Natural Gas Pipelines	$ 3,483	$ 4,661	$ 3,540
Products Pipelines	977	1,225	1,209
Terminals	1,045	1,506	1,175
CO_2	(292)	681	759
Kinder Morgan Canada	—	(2)	720
Total Segment EBDA	5,213	8,071	7,403
DD&A	(2,164)	(2,411)	(2,297)
Amortization of excess cost of equity investments	(140)	(83)	(95)
General and administrative and corporate charges	(653)	(611)	(588)
Interest, net	(1,595)	(1,801)	(1,917)
Income tax expense	(481)	(926)	(587)
Total consolidated net income	$ 180	$ 2,239	$ 1,919

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Capital expenditures			
Natural Gas Pipelines	$ 945	$ 1,377	$ 1,565
Products Pipelines	122	175	199
Terminals	433	347	386
CO_2	186	349	397
Kinder Morgan Canada	—	—	332
Corporate	21	22	25
Total consolidated capital expenditures	$ 1,707	$ 2,270	$ 2,904

	December 31,	
	2020	2019
	(In millions)	
Investments		
Natural Gas Pipelines	$ 7,262	$ 6,991
Products Pipelines	494	491
Terminals	136	251
CO_2	25	26
Total consolidated investments	$ 7,917	$ 7,759

	December 31,	
	2020	2019
	(In millions)	
Assets		
Natural Gas Pipelines	$ 48,597	$ 50,310
Products Pipelines	9,182	9,468
Terminals	8,639	8,890
CO_2	2,478	3,523
Corporate assets(d)	3,077	1,966
Total consolidated assets	$ 71,973	$ 74,157

(a) Includes costs of sales, operations and maintenance expenses, and taxes, other than income taxes.
(b) Includes loss (gain) on impairments and divestitures, net and other income, net.
(c) Includes revenues, earnings from equity investments, and other, net, less operating expenses, loss (gain) on impairments and divestitures, net and other income, net.
(d) Includes cash and cash equivalents, margin and restricted deposits, certain prepaid assets and deferred charges, including income tax related assets, risk management assets related to debt fair value adjustments, corporate headquarters in Houston, Texas and miscellaneous corporate assets (such as information technology, telecommunications equipment and legacy balances) not allocated to our reportable segments.

We do not attribute interest and debt expense to any of our reportable business segments.

Following is geographic information regarding the revenues and long-lived assets of our business:

	Year Ended December 31,		
	2020	2019	2018
	(In millions)		
Revenues from external customers			
U.S.	$ 11,625	$ 12,833	$ 13,596
Canada	—	300	447
Mexico and other foreign	75	76	101
Total consolidated revenues from external customers	$ 11,700	$ 13,209	$ 14,144

	December 31,		
	2020	2019	2018
	(In millions)		
Long-term assets, excluding goodwill and other intangibles			
U.S.	$ 46,384	$ 46,709	$ 47,468
Canada	1	1	748
Mexico and other foreign	81	82	83
Total consolidated long-lived assets	$ 46,466	$ 46,792	$ 48,299

17. Leases

Lessee

Following are components of our lease cost:

	Year Ended December 31,	
	2020	2019
	(In millions)	
Operating leases	$ 55	$ 136
Short-term and variable leases	101	92
Total lease cost(a)	$ 156	$ 228

(a) 2020 and 2019 amounts include $25 million and $46 million of capitalized lease costs.

Other information related to our operating leases are as follows:

	Year Ended December 31,	
	2020	2019
	(In millions, except lease term and discount rate)	
Operating cash flows from operating leases	$ (131)	$ (182)
Investing cash flows from operating leases	(25)	(46)
ROU assets obtained in exchange for operating lease obligations, net of retirements adjusted for currency conversion	20	102
Amortization of ROU assets	46	75
Removal of ROU assets and liabilities associated with the KML and U.S. Cochin Sale	—	(394)
Weighted average remaining lease term	11.56 years	13.40 years
Weighted average discount rate	4.27 %	4.31 %

Amounts recognized in the accompanying consolidated balance sheet are as follows:

Lease Activity	Balance sheet location	December 31, 2020	2019
		(In millions)	
ROU assets	Deferred charges and other assets	$ 303	$ 329
Short-term lease liability	Other current liabilities	40	40
Long-term lease liability	Other long-term liabilities and deferred credits	263	289
Finance lease assets	Property, plant and equipment, net	1	2
Finance lease liabilities	Long-term debt—Outstanding	1	2

Operating lease liabilities under non-cancellable leases (excluding short-term leases) as of December 31, 2020 are as follows:

Year	Commitment
	(In millions)
2021	$ 53
2022	46
2023	38
2024	34
2025	30
Thereafter	211
Total lease payments	412
Less: Interest	(109)
Present value of lease liabilities	$ 303

Short-term lease costs are not material to us and are anticipated to be similar to the current year short-term lease expense outlined in this disclosure.

18. Litigation and Environmental

We and our subsidiaries are parties to various legal, regulatory and other matters arising from the day-to-day operations of our businesses or certain predecessor operations that may result in claims against the Company. Although no assurance can be given, we believe, based on our experiences to date and taking into account established reserves and insurance, that the ultimate resolution of such items will not have a material adverse impact to our business. We believe we have meritorious defenses to the matters to which we are a party and intend to vigorously defend the Company. When we determine a loss is probable of occurring and is reasonably estimable, we accrue an undiscounted liability for such contingencies based on our best estimate using information available at that time. If the estimated loss is a range of potential outcomes and there is no better estimate within the range, we accrue the amount at the low end of the range. We disclose contingencies where an adverse outcome may be material or, in the judgment of management, we conclude the matter should otherwise be disclosed.

FERC Inquiry Regarding the Commission's Policy for Determining Return on Equity

On March 21, 2019, the FERC issued a notice of inquiry (NOI) seeking comments regarding whether the FERC should revise its policies for determining the base return on equity (ROE) used in setting cost of service rates charged by jurisdictional public utilities and interstate natural gas and liquids pipelines. The NOI sought comment on whether any aspects of the existing methodologies used by the FERC to set an ROE for a regulated entity should be changed, whether the ROE methodology should be the same across all three industries, and whether alternative methodologies should be considered. Comments were filed by industry groups, pipeline companies and shippers for review and evaluation by the FERC. On May 21, 2020, the FERC issued its Policy Statement on Determining Return on Equity for Natural Gas and Oil Pipelines (Policy Statement). As it applies to natural gas and oil pipelines, the Policy Statement requires averaging the results of the discounted cash flow model and capital asset pricing model, giving equal weight to each model, retains its existing two-thirds/one-third weighting of short and long-term growth projections in the discounted cash flow model, and excludes the risk premium or expected earnings models. On other matters raised in this proceeding, the FERC declined to adopt rigid policy changes, and will address issues, such as the appropriate sources for data sets and the specific companies to use for a given proxy group, as those issues arise in future rate proceedings on a pipeline-by-pipeline, case-by-case basis. The Policy Statement does not result in any immediate changes to any existing rates or ROEs for any of our pipelines, and any future changes to rates or ROEs for a pipeline will depend on a variety of factors that remain to be determined when they are raised and argued in connection with future or existing rate proceedings.

SFPP FERC Proceedings

The FERC approved the SFPP East Line Settlement in Docket No. IS21-138 (“EL Settlement”) on December 31, 2020 and it became final and effective on February 2, 2021. The EL Settlement resolved certain dockets in their entirety (IS09-437 and OR16-6) and resolved the SFPP East Line related disputes in other dockets which remain ongoing (OR14-35/36 and OR19-21/33/37). The amounts SFPP agreed to pay pursuant to the EL Settlement were fully accrued on or before December 31, 2020.

The tariffs and rates charged by SFPP which were not fully resolved by the EL Settlement are subject to a number of ongoing shipper-initiated proceedings at the FERC. In general, these complaints and protests allege the rates and tariffs charged by SFPP are not just and reasonable under the Interstate Commerce Act (ICA). In some of these proceedings shippers have challenged the overall rate being charged by SFPP, and in others the shippers have challenged SFPP’s index-based rate increases. The issues involved in these proceedings include, among others, whether indexed rate increases are justified, and the appropriate level of return and income tax allowance SFPP may include in its rates. If the shippers prevail on their arguments or claims, they would be entitled to seek reparations for the two-year period preceding the filing date of their complaints and/or prospective refunds in protest cases from the date of protest, and SFPP may be required to reduce its rates going forward. With respect to the ongoing shipper-initiated proceedings at the FERC that were not fully resolved by the EL Settlement, the shippers pleaded claims to at least $50 million in rate refunds and unspecified rate reductions as of the date of their complaints in 2014 and 2018. These proceedings tend to be protracted, with decisions of the FERC often appealed to the federal courts. Management believes SFPP has meritorious arguments supporting SFPP’s rates and intends to vigorously defend SFPP against these complaints and protests. We do not believe the ultimate resolution of the shipper complaints and protests seeking rate reductions or refunds in the ongoing proceedings will have a material adverse impact on our business.

EPNG FERC Proceedings

The tariffs and rates charged by EPNG were subject to two FERC proceedings (the “2008 rate case” and the “2010 rate case”). With respect to the 2008 rate case, the FERC issued its decision (Opinion 517-A) in July 2015. The FERC generally upheld its prior determinations, ordered refunds to be paid within 60 days, and stated that its findings in Opinion 517-A would apply to the same issues in the 2010 rate case. All refund obligations related to the 2008 rate case were satisfied in 2015. EPNG sought federal appellate review of Opinion 517-A. With respect to the 2010 rate case, the FERC issued its decision (Opinion 528-A) on February 18, 2016. The FERC generally upheld its prior determinations, affirmed prior findings of an Administrative Law Judge that certain shippers qualify for lower rates, and required EPNG to file revised pro forma recalculated rates consistent with Opinions 517-A and 528-A. On May 3, 2018, the FERC issued Opinion 528-B upholding its decisions in Opinion 528-A and requiring EPNG to implement the rates required by its rulings and provide refunds within 60 days. On July 2, 2018, EPNG reported to the FERC that the refunds had been provided as ordered. Also on July 2, 2018, EPNG initiated appellate review of Opinions 528, 528-A and 528-B. EPNG’s appeals in the 2008 and 2010 rate cases as well as the intervenors’ appeal in the 2010 rate case were consolidated. The U.S. Court of Appeals for the D.C. Circuit denied all petitions for review on July 24, 2020, which concludes these rate proceedings.

Gulf LNG Facility Disputes

On March 1, 2016, Gulf LNG Energy, LLC and Gulf LNG Pipeline, LLC (GLNG) received a Notice of Arbitration from Eni USA Gas Marketing LLC (Eni USA), one of two companies that entered into a terminal use agreement for capacity of the Gulf LNG Facility in Mississippi for an initial term that was not scheduled to expire until the year 2031. Eni USA is an indirect subsidiary of Eni S.p.A., a multi-national integrated energy company headquartered in Milan, Italy. Pursuant to its Notice of Arbitration, Eni USA sought declaratory and monetary relief based upon its assertion that (i) the terminal use agreement should be terminated because changes in the U.S. natural gas market since the execution of the agreement in December 2007 have “frustrated the essential purpose” of the agreement and (ii) activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC “in connection with a plan to convert the LNG Facility into a liquefaction/export facility have given rise to a contractual right on the part of Eni USA to terminate” the agreement. On June 29, 2018, the arbitration panel delivered its Award, and the panel's ruling called for the termination of the agreement and Eni USA's payment of compensation to GLNG. The Award resulted in our recording a net loss in the second quarter of 2018 of our equity investment in GLNG due to a non-cash impairment of our investment in GLNG partially offset by our share of earnings recognized by GLNG. On February 1, 2019, the Delaware Court of Chancery issued a Final Order and Judgment confirming the Award, which was paid by Eni USA on February 20, 2019.

On September 28, 2018, GLNG filed a lawsuit against Eni S.p.A. in the Supreme Court of the State of New York in New York County to enforce a Guarantee Agreement entered into by Eni S.p.A. in connection with the terminal use agreement. On December 12, 2018, Eni S.p.A. filed a counterclaim seeking unspecified damages from GLNG. This lawsuit remains pending.

On June 3, 2019, Eni USA filed a second Notice of Arbitration against GLNG asserting the same breach of contract claims that had been asserted in the first arbitration and alleging that GLNG negligently misrepresented certain facts or contentions in the first arbitration. By its second Notice of Arbitration, Eni USA sought to recover as damages some or all of the payments made by Eni USA to satisfy the Final Order and Judgment of the Court of Chancery. In response to the second Notice of Arbitration, GLNG filed a complaint with the Court of Chancery together with a motion seeking to permanently enjoin the arbitration. On January 10, 2020, the Court of Chancery entered an Order and Final Judgment granting GLNG's motion to enjoin arbitration of the negligent misrepresentation claim, but denying the motion to enjoin arbitration of the breach of contract claims. The parties filed cross appeals of the Final Judgment. On November 17, 2020, the Delaware Supreme Court ruled in favor of GLNG and a permanent injunction was entered prohibiting Eni USA from re-arbitrating both the breach of contract and negligent misrepresentation claims.

On December 20, 2019, GLNG's remaining customer, Angola LNG Supply Services LLC (ALSS), filed a Notice of Arbitration seeking a declaration that its terminal use agreement should be deemed terminated as of March 1, 2016 on substantially the same terms and conditions as set forth in the arbitration award pertaining to Eni USA. ALSS also seeks a declaration that activities allegedly undertaken by affiliates of Gulf LNG Holdings Group LLC in connection with the pursuit of an LNG liquefaction export project have given rise to a contractual right on the part of ALSS to terminate the agreement. ALSS also seeks a monetary award directing GLNG to reimburse ALSS for all reservation charges and operating fees paid by ALSS after December 31, 2016 plus interest. A final decision in this arbitration is expected before the end of the third quarter of 2021.

GLNG intends to continue to vigorously prosecute and defend all of the foregoing proceedings.

Continental Resources, Inc. v. Hiland Partners Holdings, LLC

On December 8, 2017, Continental Resources, Inc. (CLR) filed an action in Garfield County, Oklahoma state court alleging that Hiland Partners Holdings, LLC (Hiland Partners) breached a Gas Purchase Agreement, dated November 12, 2010, as amended (GPA), by failing to receive and purchase all of CLR's dedicated gas under the GPA (produced in three North Dakota counties). CLR also alleged fraud, maintaining that Hiland Partners promised the construction of several additional facilities to process the gas without an intention to build the facilities. Hiland Partners denied these allegations, but the parties entered into a settlement agreement in June 2018, under which CLR agreed to release all of its claims in exchange for Hiland Partners' construction of 10 infrastructure projects by November 1, 2020. CLR has filed an amended petition in which it asserts that Hiland Partners' failure to construct certain facilities by specific dates nullifies the release contained in the settlement agreement. CLR's amended petition makes additional claims under both the GPA and a May 8, 2008 gas purchase contract covering additional North Dakota counties, including CLR's contention that Hiland Partners is not allowed to deduct third-party processing fees from the gas purchase price. CLR seeks damages in excess of $225 million. Hiland Partners denies and will vigorously defend against these claims.

Pipeline Integrity and Releases

From time to time, despite our best efforts, our pipelines experience leaks and ruptures. These leaks and ruptures may cause explosions, fire, and damage to the environment, damage to property and/or personal injury or death. In connection with these incidents, we may be sued for damages caused by an alleged failure to properly mark the locations of our pipelines and/or to properly maintain our pipelines. Depending upon the facts and circumstances of a particular incident, state and federal regulatory authorities may seek civil and/or criminal fines and penalties.

General

As of December 31, 2020 and 2019, our total reserve for legal matters was $273 million and $203 million, respectively.

Environmental Matters

We and our subsidiaries are subject to environmental cleanup and enforcement actions from time to time. In particular, CERCLA generally imposes joint and several liability for cleanup and enforcement costs on current and predecessor owners and operators of a site, among others, without regard to fault or the legality of the original conduct, subject to the right of a liable party to establish a "reasonable basis" for apportionment of costs. Our operations are also subject to local, state and federal laws and regulations relating to protection of the environment. Although we believe our operations are in substantial compliance with applicable environmental laws and regulations, risks of additional costs and liabilities are inherent in pipeline, terminal and CO_2 field and oil field operations, and there can be no assurance that we will not incur significant costs and liabilities. Moreover, it is possible that other developments could result in substantial costs and liabilities to us, such as increasingly stringent environmental laws, regulations and enforcement policies under the terms of authority of those laws, and claims for damages to property or persons resulting from our operations.

We are currently involved in several governmental proceedings involving alleged violations of local, state and federal environmental and safety regulations. As we receive notices of non-compliance, we attempt to negotiate and settle such matters where appropriate. These alleged violations may result in fines and penalties, but we do not believe any such fines and penalties will be material to our business, individually or in the aggregate. We are also currently involved in several governmental proceedings involving groundwater and soil remediation efforts under state or federal administrative orders or related remediation programs. We have established a reserve to address the costs associated with the remediation efforts.

In addition, we are involved with and have been identified as a potentially responsible party (PRP) in several federal and state Superfund sites. Environmental reserves have been established for those sites where our contribution is probable and reasonably estimable. In addition, we are from time to time involved in civil proceedings relating to damages alleged to have occurred as a result of accidental leaks or spills of refined petroleum products, NGL, natural gas or CO_2.

Portland Harbor Superfund Site, Willamette River, Portland, Oregon

On January 6, 2017, the EPA issued a Record of Decision (ROD) that established a final remedy and cleanup plan for an industrialized area on the lower reach of the Willamette River commonly referred to as the Portland Harbor Superfund Site (PHSS). The cost for the final remedy is estimated by the EPA to be approximately $1.1 billion and active cleanup is expected to take as long as 13 years to complete. KMLT, KMBT, and 90 other PRPs identified by the EPA are involved in a non-judicial allocation process to determine each party's respective share of the cleanup costs related to the final remedy set forth by the ROD. We are participating in the allocation process on behalf of KMLT (in connection with its ownership or operation of two facilities acquired from GATX Terminals Corporation) and KMBT (in connection with its ownership or operation of two facilities). Effective January 31, 2020, KMLT entered into separate Administrative Settlement Agreements and Orders on Consent (ASAOC) to complete remedial design for two distinct areas within the PHSS associated with KMLT's facilities. The ASAOC obligates KMLT to pay a share of the remedial design costs for cleanup activities related to these two areas as required by the ROD. Our share of responsibility for the PHSS costs will not be determined until the ongoing non-judicial allocation process is concluded or a lawsuit is filed that results in a judicial decision allocating responsibility. Until the allocation process is completed, we are unable to reasonably estimate the extent of our liability for the costs related to the design of the proposed remedy and cleanup of the PHSS. In addition to CERCLA cleanup costs, we are reviewing and will attempt to settle, if possible, natural resource damage (NRD) claims asserted by state and federal trustees following their natural resource assessment of the PHSS. At this time, we are unable to reasonably estimate the extent of our potential NRD liability.

Uranium Mines in Vicinity of Cameron, Arizona

In the 1950s and 1960s, Rare Metals Inc., a historical subsidiary of EPNG, mined approximately 20 uranium mines in the vicinity of Cameron, Arizona, many of which are located on the Navajo Indian Reservation. The mining activities were in response to numerous incentives provided to industry by the U.S. to locate and produce domestic sources of uranium to support the Cold War-era nuclear weapons program. In May 2012, EPNG received a general notice letter from the EPA notifying EPNG of the EPA's investigation of certain sites and its determination that the EPA considers EPNG to be a PRP within the meaning of CERCLA. In August 2013, EPNG and the EPA entered into an Administrative Order on Consent and Scope of Work pursuant to which EPNG is conducting environmental assessments of the mines and the immediate vicinity. On September 3, 2014, EPNG filed a complaint in the U.S. District Court for the District of Arizona seeking cost recovery and contribution from the applicable federal government agencies toward the cost of environmental activities associated with the mines. The U.S. District Court issued an order on April 16, 2019 that allocated 35% of past and future response costs to the U.S. The decision does not provide or establish the scope of a remedial plan with respect to the sites, nor does it establish the total cost for addressing the sites, all of which remain to be determined in subsequent proceedings and adversarial actions, if necessary, with the EPA. Until such issues are determined, we are unable to reasonably estimate the extent of our potential liability. Because costs associated with any remedial plan approved by the EPA are expected to be spread over at least several years, we do not anticipate that our share of the costs of the remediation will have a material adverse impact to our business.

Lower Passaic River Study Area of the Diamond Alkali Superfund Site, New Jersey

EPEC Polymers, Inc. (EPEC Polymers) and EPEC Oil Company Liquidating Trust (EPEC Oil Trust), former El Paso Corporation entities now owned by KMI, are involved in an administrative action under CERCLA known as the Lower Passaic River Study Area (Site) concerning the lower 17-mile stretch of the Passaic River. It has been alleged that EPEC Polymers and EPEC Oil Trust may be PRPs under CERCLA based on prior ownership and/or operation of properties located along the relevant section of the Passaic River. EPEC Polymers and EPEC Oil Trust entered into two Administrative Orders on Consent (AOCs) with the EPA which obligate them to investigate and characterize contamination at the Site. They are also part of a joint defense group of approximately 44 cooperating parties, referred to as the Cooperating Parties Group (CPG), which is directing and funding the AOC work required by the EPA. Under the first AOC, the CPG submitted draft remedial investigation and feasibility studies (RI/FS) of the Site to the EPA in 2015, and EPA approval remains pending. Under the second AOC, the CPG conducted a CERCLA removal action at the Passaic River Mile 10.9, and is obligated to conduct EPA-directed post-remedy monitoring in the removal area. We have established a reserve for the anticipated cost of compliance with these two AOCs.

On March 4, 2016, the EPA issued its Record of Decision (ROD) for the lower eight miles of the Site. At that time the final cleanup plan in the ROD was estimated by the EPA to cost $1.7 billion. On October 5, 2016, the EPA entered into an AOC with Occidental Chemical Company (OCC), a member of the PRP group requiring OCC to spend an estimated $165 million to perform engineering and design work necessary to begin the cleanup of the lower eight miles of the Site. The design work is underway. Initial expectations were that the design work would take four years to complete. The cleanup is expected to take at least six years to complete once it begins.

In addition, the EPA and numerous PRPs, including EPEC Polymers, are engaged in an allocation process for the implementation of the remedy for the lower eight miles of the Site. That process was completed December 28, 2020. We anticipate the PRPs, including EPEC Polymers, will engage in further discussions with the EPA during 2021. There remains significant uncertainty as to the implementation and associated costs of the remedy set forth in the ROD. There is also uncertainty as to the impact of the EPA FS directive for the upper nine miles of the Site not subject to the lower eight mile ROD. In a letter dated October 10, 2018, the EPA directed the CPG to prepare a streamlined FS for the Site that evaluates interim remedy alternatives for sediments in the upper nine miles of the Site. Until the PRPs engage in discussions with the EPA, the FS is completed, and the RI/FS is finalized, we are unable to reasonably estimate the extent of our potential liability.

Louisiana Governmental Coastal Zone Erosion Litigation

Beginning in 2013, several parishes in Louisiana and the City of New Orleans filed separate lawsuits in state district courts in Louisiana against a number of oil and gas companies, including TGP and SNG. In these cases, the parishes and New Orleans, as Plaintiffs, allege that certain of the defendants' oil and gas exploration, production and transportation operations were conducted in violation of the State and Local Coastal Resources Management Act of 1978, as amended (SLCRMA) and that those operations caused substantial damage to the coastal waters of Louisiana and nearby lands. The Plaintiffs seek, among other relief, unspecified money damages, attorneys' fees, interest, and payment of costs necessary to restore the affected areas. There are more than 40 of these cases pending in Louisiana against oil and gas companies, one of which is against TGP and one of which is against SNG, both described further below.

On November 8, 2013, the Parish of Plaquemines, Louisiana filed a petition for damages in the state district court for Plaquemines Parish, Louisiana against TGP and 17 other energy companies, alleging that the defendants' operations in Plaquemines Parish violated SLCRMA and Louisiana law, and caused substantial damage to the coastal waters and nearby lands. Plaquemines Parish seeks, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to restore the allegedly affected areas. In May 2018, the case was removed to the U.S. District Court for the Eastern District of Louisiana. In May 2019, the case was remanded to the state district court for Plaquemines Parish. At the same time, the U.S. District Court certified a federal jurisdiction issue for review by the U.S. Fifth Circuit Court of Appeals. On August 10, 2020, the Fifth Circuit affirmed remand. The defendants filed a motion for rehearing which is pending. The case remains effectively stayed pending a final ruling by the Court of Appeals. Until these and other issues are determined, we are not able to reasonably estimate the extent of our potential liability, if any. We will continue to vigorously defend this case.

On March 29, 2019, the City of New Orleans and Orleans Parish (collectively, Orleans) filed a petition for damages in the state district court for Orleans Parish, Louisiana against SNG and 10 other energy companies alleging that the defendants' operations in Orleans Parish violated the SLCRMA and Louisiana law, and caused substantial damage to the coastal waters and nearby lands. Orleans seeks, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to restore the allegedly affected areas. In April 2019, the case was removed to the U.S. District Court for the Eastern District of Louisiana. In May 2019, Orleans moved to remand the case to the state district court. In January 2020, the U.S. District Court ordered the case to be stayed and administratively closed pending the resolution of issues in a separate case to which SNG is not a party; *Parish of Cameron vs. Auster Oil & Gas, Inc.*, pending in U.S. District Court for the Western District of Louisiana; after which either party may move to re-open the case. Until these and other issues are determined, we are not able to reasonably estimate the extent of our potential liability, if any. We will continue to vigorously defend this case.

Louisiana Landowner Coastal Erosion Litigation

Beginning in January 2015, several private landowners in Louisiana, as Plaintiffs, filed separate lawsuits in state district courts in Louisiana against a number of oil and gas pipeline companies, including two cases against TGP, two cases against SNG, and two cases against both TGP and SNG. In these cases, the Plaintiffs allege that the defendants failed to properly maintain pipeline canals and canal banks on their property, which caused the canals to erode and widen and resulted in substantial land loss, including significant damage to the ecology and hydrology of the affected property, and damage to timber and wildlife. The Plaintiffs allege the defendants' conduct constitutes a breach of the subject right of way agreements, is inconsistent with prudent operating practices, violates Louisiana law, and that defendants' failure to maintain canals and canal banks constitutes negligence and trespass. The plaintiffs seek, among other relief, unspecified money damages, attorney fees, interest, and payment of costs necessary to return the canals and canal banks to their as-built conditions and restore and remediate the affected property. The Plaintiffs also seek a declaration that the defendants are obligated to take steps to maintain canals and canal banks going forward. One of these cases filed by Vintage Assets, Inc. and several landowners against SNG, TGP, and another defendant was tried in 2017 to the U.S. District Court for the Eastern District of Louisiana. On May 4, 2018, the U.S. District Court entered a judgment ruling in favor of the plaintiffs on certain of their contract claims. The Court stayed the judgment pending appeal. The parties each filed a separate appeal to the U.S. Court of Appeals for the Fifth Circuit. In October 2018, the Court of Appeals dismissed the appeals for lack of subject matter jurisdiction. In April 2019 the case was remanded to the state district court for Plaquemines Parish, Louisiana for further proceedings. On October 2, 2020, the case was settled for an amount which is not material to our business. We will continue to vigorously defend the remaining cases.

General

Although it is not possible to predict the ultimate outcomes, we believe that the resolution of the environmental matters set forth in this note, and other matters to which we and our subsidiaries are a party, will not have a material adverse effect on our business. As of December 31, 2020 and 2019, we have accrued a total reserve for environmental liabilities in the amount of $250 million and $259 million, respectively. In addition, as of December 31, 2020 and 2019, we have recorded a receivable of $12 million and $15 million, respectively, for expected cost recoveries that have been deemed probable.

19. Recent Accounting Pronouncements

Accounting Standards Updates

Reference Rate Reform (Topic 848)

On March 12, 2020, the FASB issued ASU No. 2020-04, "*Reference Rate Reform - Facilitation of the Effects of Reference Rate Reform on Financial Reporting.*" This ASU provides temporary optional expedients and exceptions to GAAP guidance on contract modifications and hedge accounting to ease the financial reporting burdens of the expected market transition from LIBOR and other interbank offered rates to alternative reference rates, such as the SOFR. Entities can elect not to apply certain modification accounting requirements to contracts affected by reference rate reform, if certain criteria are met. An entity that makes this election would not have to remeasure the contracts at the modification date or reassess a previous accounting determination. Entities can also elect various optional expedients that would allow them to continue applying hedge accounting for hedging relationships affected by reference rate reform, if certain criteria are met.

On January 7, 2021, the FASB issued ASU No. 2021-01, "*Reference Rate Reform (Topic 848): Scope.*" This ASU clarifies that all derivative instruments affected by changes to the interest rates used for discounting, margining or contract price alignment ("The Discounting Transition") are in the scope of ASC 848 and therefore qualify for the available temporary optional expedients and exceptions. As such, entities that employ derivatives that are the designated hedged item in a hedge relationship where perfect effectiveness is assumed can continue to apply hedge accounting without de-designating the hedging relationship to the extent such derivatives are impacted by the Discounting Transition.

The guidance is effective upon issuance and generally can be applied through December 31, 2022. We are currently reviewing the effect of Topic 848 to our financial statements.

ASU No. 2020-06

On August 5, 2020, the FASB issued ASU No. 2020-06, "*Debt - Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging - Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity.*" This ASU (i) simplifies an issuer's accounting for convertible instruments by eliminating two of the three models in ASC 470-20 that require separate accounting for embedded conversion features, (ii) amends diluted EPS calculations for convertible instruments by requiring the use of the if-converted method and (iii) simplifies the settlement assessment entities are required to perform on contracts that can potentially settle in an entity's own equity by removing certain requirements. ASU No. 2020-06 will be effective for us for the fiscal year beginning January 1, 2022, and earlier adoption is permitted. We are currently reviewing the effect of this ASU to our financial statements.

Supplemental Quarterly Financial Data (Unaudited)

	Quarters Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(In millions, except per share amounts)			
2020				
Revenues	$ 3,106	$ 2,560	$ 2,919	$ 3,115
Operating Income (Loss)	43	(282)	819	980
Net (Loss) Income	(291)	(624)	472	623
Net (Loss) Income Attributable to Kinder Morgan, Inc. and Common Stockholders	(306)	(637)	455	607
Basic and Diluted (Loss) Earnings Per Common Share	(0.14)	(0.28)	0.20	0.27
2019				
Revenues	$ 3,429	$ 3,214	$ 3,214	$ 3,352
Operating Income	1,018	973	951	1,931
Net Income	567	528	517	627
Net Income Attributable to Kinder Morgan, Inc. and Common Stockholders	556	518	506	610
Basic and Diluted Earnings Per Common Share	0.24	0.23	0.22	0.27

Item 16. ***Form 10-K Summary.***

Not Applicable.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

KINDER MORGAN, INC.
Registrant

/s/ David P. Michels

David P. Michels
Vice President and Chief Financial Officer

Date: February 5, 2021

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/s/ DAVID P. MICHELS David P. Michels	Vice President and Chief Financial Officer (principal financial officer and principal accounting officer)	February 5, 2021
/s/ STEVEN J. KEAN Steven J. Kean	Chief Executive Officer (principal executive officer); Director	February 5, 2021
/s/ RICHARD D. KINDER Richard D. Kinder	Executive Chairman	February 5, 2021
/s/ KIMBERLY A. DANG Kimberly A. Dang	President; Director	February 5, 2021
/s/ TED A. GARDNER Ted A. Gardner	Director	February 5, 2021
/s/ ANTHONY W. HALL, JR. Anthony W. Hall, Jr.	Director	February 5, 2021
/s/ GARY L. HULTQUIST Gary L. Hultquist	Director	February 5, 2021
/s/ RONALD L. KUEHN, JR. Ronald L. Kuehn, Jr.	Director	February 5, 2021
/s/ DEBORAH A. MACDONALD Deborah A. Macdonald	Director	February 5, 2021
/s/ MICHAEL C. MORGAN Michael C. Morgan	Director	February 5, 2021
/s/ ARTHUR C. REICHSTETTER Arthur C. Reichstetter	Director	February 5, 2021
/s/ C. PARK SHAPER C. Park Shaper	Director	February 5, 2021
/s/ WILLIAM A. SMITH William A. Smith	Director	February 5, 2021
/s/ JOEL V. STAFF Joel V. Staff	Director	February 5, 2021
/s/ ROBERT F. VAGT Robert F. Vagt	Director	February 5, 2021
/s/ PERRY M. WAUGHTAL Perry M. Waughtal	Director	February 5, 2021

Exhibit 10.14

CROSS GUARANTEE AGREEMENT

This CROSS GUARANTEE AGREEMENT is dated as of November 26, 2014 (as amended, restated, supplemented or otherwise modified from time to time, this "Agreement"), by each of the signatories listed on the signature pages hereto and each of the other entities that becomes a party hereto pursuant to Section 19 (the "Guarantors" and individually, a "Guarantor"), for the benefit of the Guaranteed Parties (as defined below).

W I T N E S S E T H:

WHEREAS, Kinder Morgan, Inc., a Delaware corporation ("KMI"), and certain of its direct and indirect Subsidiaries have outstanding senior, unsecured Indebtedness and may from time to time issue additional senior, unsecured Indebtedness;

WHEREAS, each Guarantor, other than KMI, is a direct or indirect Subsidiary of KMI;

WHEREAS, each Guarantor desires to provide the guarantee set forth herein with respect to the Indebtedness of such Guarantors that constitutes the Guaranteed Obligations; and

WHEREAS, each Guarantor acknowledges that it will derive substantial direct and indirect benefit from the making of the guarantees hereby;

NOW, THEREFORE, in consideration of the premises, the Guarantors hereby agree with each other for the benefit of the Guaranteed Parties as follows:

1. Defined Terms.

(a) As used in this Agreement, the following terms have the meanings specified below:

"Agreement" has the meaning provided in the preamble hereto.

"Bankruptcy Code" means Title 11 of the United States Code, as now or hereafter in effect, or any successor thereto.

"Capital Stock" means, with respect to any Person, any and all shares, interests, rights to purchase, warrants, options, participations or other equivalents (however designated) of such Person's equity, including (i) all common stock and preferred stock, any limited or general partnership interest and any limited liability company member interest, (ii) beneficial interests in trusts, and (iii) any other interest or participation that confers upon a Person the right to receive a share of the profits and losses of, or distribution of assets of, the issuing Person.

"CFC" means a Person that is a "controlled foreign corporation" within the meaning of Section 957 of the Internal Revenue Code of 1986, as amended.

"Commodity Exchange Act" means the Commodity Exchange Act (7 U.S.C. § 1 et seq.), as amended from time to time, and any successor statute.

"Consolidated Assets" means, at the date of any determination thereof, the total assets of KMI and its Subsidiaries as set forth on a consolidated balance sheet of KMI and its Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Consolidated Tangible Assets" means, at the date of any determination thereof, Consolidated Assets after deducting therefrom the value, net of any applicable reserves and accumulated amortization, of all goodwill, trade names, trademarks, patents and other like intangible assets, all as set forth, or on a pro forma basis would be set forth, on a consolidated balance sheet of KMI and its Subsidiaries for their most recently completed fiscal quarter, prepared in accordance with GAAP.

"Domestic Subsidiary" means any Subsidiary of KMI organized under the laws of any jurisdiction within the United States.

"Excluded Subsidiary" means (i) any Subsidiary that is not a Wholly-owned Domestic Operating Subsidiary, (ii) any Domestic Subsidiary that is a Subsidiary of a CFC or any Domestic Subsidiary (including a disregarded entity for U.S. federal income tax purposes) substantially all of whose assets (held directly or through Subsidiaries) consist of Capital Stock of one or more CFCs or Indebtedness of such CFCs, (iii) any Immaterial Subsidiary, (iv) any Subsidiary listed on Schedule III, (v) each of Calnev Pipe Line LLC, SFPP, L.P., Kinder Morgan G.P., Inc. and EPEC Realty, Inc. and each of its Subsidiaries, (vi) any other Subsidiary that is not a Guarantor under the Revolving Credit Agreement Guarantee, (vii) any not-for-profit Subsidiary, (viii) any Subsidiary that is prohibited by a Requirement of Law from guaranteeing the Guaranteed Obligations, and (ix) any Subsidiary acquired by KMI or its Subsidiaries after the date of this Agreement to the extent, and so long as, the financing documentation governing any existing Indebtedness of such Subsidiary that survives such acquisition prohibits such Subsidiary from guaranteeing the Guaranteed Obligations; *provided*, that notwithstanding the foregoing, any Subsidiary that is party to the Revolving Credit Agreement Guarantee or that Guarantees any senior notes or senior debt securities issued by KMI (other than pursuant to this Agreement) shall not constitute an Excluded Subsidiary for so long as such Guarantee is in effect.

"Excluded Swap Obligation" means, with respect to any Guarantor, any Swap Obligation if, and to the extent that, all or a portion of the Guarantee of such Guarantor of such Swap Obligation (or any Guarantee thereof) is or becomes illegal under the Commodity Exchange Act or any rule, regulation or order of the Commodity Futures Trading Commission (or the application or official interpretation of any thereof) by virtue of such Guarantor's failure for any reason to constitute an "eligible contract participant" as defined in the Commodity Exchange Act and the regulations thereunder at the time the Guarantee of such Guarantor becomes effective with respect to such Swap Obligation. If a Swap Obligation arises under a master agreement governing more than one swap, such exclusion shall apply only to the portion of such Swap Obligation that is attributable to swaps for which such Guarantee is or becomes illegal.

"GAAP" means generally accepted accounting principles in the United States of America from time to time, including as set forth in the opinions, statements and pronouncements of the Accounting Principles Board of the American Institute of Certified Public Accountants and the Financial Accounting Standards Board.

"Governmental Authority" means the government of the United States of America or any other nation, or of any political subdivision thereof, whether state or local, and any agency, authority, instrumentality, regulatory body, court, central bank or other entity exercising executive, legislative, judicial, taxing, regulatory or administrative powers or functions of or pertaining to government (including any supra national bodies such as the European Union or the European Central Bank).

"Guarantee" of or by any Person (the "guarantor") means any obligation, contingent or otherwise, of the guarantor guaranteeing or having the economic effect of guaranteeing any Indebtedness or other obligation of any other Person (the "primary obligor") in any manner, whether directly or indirectly, and including any obligation of the guarantor, direct or indirect, (i) to purchase or pay (or advance or supply funds for the purchase or payment of) such Indebtedness or other obligation or to purchase (or to advance or supply funds for the purchase of) any security for the payment thereof, (ii) to purchase or lease property, securities or services for the purpose of assuring the owner of such Indebtedness or other obligation of the payment thereof, (iii) to maintain working capital, equity capital or any other financial statement condition or liquidity of the primary obligor so as to enable the primary obligor to pay such Indebtedness or other obligation or (iv) as an account party in respect of any letter of credit or letter of guaranty issued to support such Indebtedness or obligation; *provided* that the term Guarantee shall not include endorsements for collection or deposit in the ordinary course of business.

"Guarantee Termination Date" has the meaning set forth in Section 2(d).

"Guaranteed Obligations" means the Indebtedness set forth on Schedule I hereto, as such schedule may be amended from time to time in accordance with the terms of this Agreement; *provided* that the term "Guaranteed Obligations" shall exclude any Excluded Swap Obligations.

"Guaranteed Parties" means, collectively, (i) in the case of Guaranteed Obligations that are governed by trust indentures, the holders (as that term is defined in the applicable trust indenture) of such Guaranteed Obligations, (ii) in the case of Guaranteed Obligations that are governed by loan agreements, credit agreements, or similar agreements, the lenders providing such loans or credit, and (iii) in the case of Guaranteed Obligations with respect to Hedging Agreements, the counterparties under such agreements.

"Guarantor" has the meaning provided in the preamble hereto. Schedule II hereto, as such schedule may be amended from time to time in accordance with the terms of this Agreement, sets forth the name of each Guarantor.

"Hedging Agreement" means a financial instrument, agreement or security which hedges or is used to hedge or manage the risk associated with a change in interest rates, foreign currency exchange rates or commodity prices (but excluding any purchase, swap, derivative contract or similar agreement relating to power, electricity or any related commodity product).

"Immaterial Subsidiary" means any Subsidiary that is not a Material Subsidiary.

"Indebtedness" means, collectively, (i) any senior, unsecured obligation created or assumed by any Person for borrowed money, including all obligations of such Person evidenced by bonds, debentures, notes or similar instruments (other than surety, performance and guaranty bonds), and (ii) all payment obligations of any Person with respect to obligations under Hedging Agreements.

"Investment Grade Rating" means a rating equal to or higher than Baa3 by Moody's and BBB- by S&P; *provided, however,* that if (i) either of Moody's or S&P changes its rating system, such ratings shall be the equivalent ratings after such changes or (ii) Moody's or S&P shall not make a rating of a Guaranteed Obligation publicly available, the references above to Moody's or S&P or both of them, as the case may be, shall be to a nationally recognized U.S. rating agency or agencies, as the case may be, selected by KMI and the references to the ratings categories above shall be to the corresponding rating categories of such rating agency or rating agencies, as the case may be.

"Issuer" means the issuer, borrower, or other applicable primary obligor of a Guaranteed Obligation.

"KMI" has the meaning provided in the recitals hereto.

"Lien" means, with respect to any asset (i) any mortgage, deed of trust, lien, pledge, hypothecation, encumbrance, charge or security interest in, on or of such asset, and (ii) the interest of a vendor or a lessor under any conditional sale agreement, capital lease or title retention agreement (or any financing lease having substantially the same economic effect as any of the foregoing) relating to such asset.

"Material Subsidiary" means, as at any date of determination, any Subsidiary of KMI whose total tangible assets (for purposes of the below, when combined with the tangible assets of such Subsidiary's Subsidiaries, after eliminating intercompany obligations) as at such date of determination are greater than or equal to 5% of Consolidated Tangible Assets as of the last day of the fiscal quarter most recently ended for which financial statements of KMI have been filed with the SEC.

"Moody's" means Moody's Investors Service, Inc. and its successors.

"Operating Subsidiary" means any operating company that is a Subsidiary of KMI.

"Person" means any natural person, corporation, limited liability company, trust, joint venture, association, company, partnership, Governmental Authority or other entity.

"Qualified ECP Guarantor" means, in respect of any Swap Obligation, each Guarantor that has total assets exceeding $10,000,000 at the time the relevant Guarantee becomes effective with respect to such Swap Obligation or such other person as constitutes an "eligible contract participant" under the Commodity Exchange Act or any regulations promulgated thereunder and can cause another person to qualify as an "eligible contract participant" at such time by entering into a keepwell under Section 1a(18)(A)(v)(II) of the Commodity Exchange Act.

"Rating Agencies" means Moody's and S&P; *provided* that, if at the relevant time neither Moody's nor S&P shall be rating the relevant Guaranteed Obligation, then "Rating Agencies" shall mean another nationally recognized rating service that rates such Guaranteed Obligation.

"Rating Date" means the date immediately prior to the earlier of (i) the occurrence of a Release Event and (ii) public notice of the intention to effect a Release Event.

"Rating Decline" means, with respect to a Guaranteed Obligation, the occurrence of the following on, or within 90 days after, the date of the occurrence of a Release Event or of public notice of the intention to effect a Release Event (which period may be extended so long as the rating of such Guaranteed Obligation is under publicly announced consideration for possible downgrade by either of the Rating Agencies): (i) in the event such Guaranteed Obligation is assigned an Investment Grade Rating by both Rating Agencies on the Rating Date, the rating of such Guaranteed Obligation by one or both of the Rating Agencies shall be below an Investment Grade Rating; or (ii) in the event such Guaranteed Obligation is rated below an Investment Grade Rating by either of the Rating Agencies on the Rating Date, any such below-Investment Grade Rating of such Guaranteed Obligation shall be decreased by one or more gradations (including gradations within rating categories as well as between rating categories).

"Release Event" has the meaning set forth in Section 6(b).

"Requirement of Law" means any law, statute, code, ordinance, order, determination, rule, regulation, judgment, decree, injunction, franchise, permit, certificate, license, authorization or other directive or requirement (whether or not having the force of law), including environmental laws, energy regulations and occupational, safety and health standards or controls, of any Governmental Authority.

Revolving Credit Agreement" means the Revolving Credit Agreement, dated as of September 19, 2014, among KMI, the lenders party thereto and Barclays Bank PLC, as administrative agent, as such credit agreement may be amended, modified, supplemented or restated from time to time, or refunded, refinanced, restructured, replaced, renewed, repaid or extended from time to time (whether with the original agents and lenders or other agents or lenders or trustee or otherwise, and whether provided under the original credit agreement or other credit agreements or note indentures or otherwise), including, without limitation, increasing the amount of available borrowings or other Indebtedness thereunder.

"Revolving Credit Agreement Guarantee" means the Guarantee Agreement, dated as of November 26, 2014, made by the Subsidiaries of KMI party thereto in favor of Barclays Bank PLC, as administrative agent, for the benefit of the lenders and the issuing banks under the Revolving Credit Agreement, as such guarantee agreement may be amended, modified, supplemented or restated from time to time, and as it may be replaced or renewed from time to time in connection with any amendment, modification, supplement, restatement, refunding, refinancing, restructuring, replacement, renewal, repayment, or extension of any Revolving Credit Agreement from time to time.

"S&P" means Standard & Poor's Rating Services, a division of The McGraw-Hill Companies, Inc., and its successors.

"SEC" means the United States Securities and Exchange Commission.

"Subsidiary" means, with respect to any Person (the "parent") at any date, any corporation, limited liability company, partnership, association or other entity the accounts of which would be consolidated with those of the parent in the parent's consolidated financial statements if such financial statements were prepared in accordance with GAAP as of such date, as well as any other corporation, limited liability company, partnership, association or other entity (a) of which securities or other ownership interests representing more than 50% of the equity or more than 50% of the ordinary voting power or, in the case of a partnership, more than 50% of the general partner interests are, as of such date, owned, controlled or held, or (b) that is, as of such date, otherwise controlled, by the parent or one or more Subsidiaries of the parent or by the parent and one or more Subsidiaries of the parent. Unless the context otherwise clearly requires, references in this Agreement to a "Subsidiary" or the "Subsidiaries" refer to a Subsidiary or the Subsidiaries of KMI. Notwithstanding the foregoing, Plantation Pipe Line Company, a Delaware and Virginia corporation, shall not be a Subsidiary of KMI until such time as its assets and liabilities, profit or loss and cash flow are required under GAAP to be consolidated with those of KMI.

"Swap Obligation" means, with respect to any Guarantor, any obligation to pay or perform under any agreement, contract or transaction that constitutes a "swap" within the meaning of Section 1a(47) of the Commodity Exchange Act.

"Wholly-owned Domestic Operating Subsidiary" means any Wholly-owned Subsidiary that constitutes (i) a Domestic Subsidiary and (ii) an Operating Subsidiary.

"Wholly-owned Subsidiary" means a Subsidiary of which all issued and outstanding Capital Stock (excluding in the case of a corporation, directors' qualifying shares) is directly or indirectly owned by KMI.

(b) The words "hereof", "herein" and "hereunder" and words of similar import when used in this Agreement shall refer to this Agreement as a whole and not to any particular provision of this Agreement, and Section references are to Sections of this Agreement unless otherwise specified. The words "include", "includes" and "including" shall be deemed to be followed by the phrase "without limitation".

(c) The meanings given to terms defined herein shall be equally applicable to both the singular and plural forms of such terms.

2. Guarantee.

(a) Subject to the provisions of Section 2(b), each of the Guarantors hereby, jointly and severally, unconditionally and irrevocably, guarantees, as primary obligor and not merely as surety, for the benefit of the Guaranteed Parties, the prompt and complete payment when due (whether at the stated maturity, by acceleration or otherwise) of the Guaranteed Obligations; *provided* that each Guarantor shall be released from its respective guarantee obligations under this Agreement as provided in Section 6(b). Upon the failure of an Issuer to punctually pay any Guaranteed Obligation, each Guarantor shall, upon written demand by the applicable Guaranteed Party to such Guarantor, pay or cause to be paid such amounts.

(b) Anything herein to the contrary notwithstanding, the maximum liability of each Guarantor hereunder shall in no event exceed the amount that can be guaranteed by such Guarantor under the Bankruptcy Code or any applicable laws relating to fraudulent conveyances, fraudulent transfers or the insolvency of debtors after giving full effect to the liability under this Agreement and its related contribution rights set forth in this Section 2, but before taking into account any liabilities under any other Guarantees.

(c) Each Guarantor agrees that the Guaranteed Obligations may at any time and from time to time exceed the amount of the liability of such Guarantor hereunder (as a result of the limitations set forth in Section 2(b) or elsewhere in this Agreement) without impairing this Agreement or affecting the rights and remedies of any Guaranteed Party hereunder.

(d) No payment or payments made by any Issuer, any of the Guarantors, any other guarantor or any other Person or received or collected by any Guaranteed Party from any Issuer, any of the Guarantors, any other guarantor or any other Person by virtue of any action or proceeding or any set-off or appropriation or application at any time or from time to time in reduction of or in payment of any Guaranteed Obligation shall be deemed to modify, reduce, release or otherwise affect the liability of any Guarantor hereunder, which shall, notwithstanding any such payment or payments, other than payments made by such Guarantor in respect of such Guaranteed Obligation or payments received or collected from such Guarantor in respect of such Guaranteed Obligation, remain liable for the Guaranteed Obligations up to the maximum liability of such Guarantor hereunder until all Guaranteed Obligations (other than any contingent indemnity obligations not then due and any letters of credit that remain outstanding which have been fully cash collateralized or otherwise back-stopped to the reasonable satisfaction of the applicable issuing bank) shall have been discharged by payment in full or shall have been deemed paid and discharged by defeasance pursuant to the terms of the instruments governing such Guaranteed Obligations (the "Guarantee Termination Date").

(e) If and to the extent required in order for the obligations of any Guarantor hereunder to be enforceable under applicable federal, state and other laws relating to the insolvency of debtors, the maximum liability of such Guarantor hereunder shall be limited to the greatest amount which can lawfully be guaranteed by such Guarantor under such laws, after giving effect to any rights of contribution, reimbursement and subrogation arising hereunder. Each Guarantor acknowledges and agrees that, to the extent not prohibited by applicable law, (i) such Guarantor (as opposed to its creditors, representatives of creditors or bankruptcy trustee, including such Guarantor in its capacity as debtor in possession exercising any powers of a bankruptcy trustee) has no personal right under such laws to reduce, or request any judicial relief that has the effect of reducing, the amount of its liability under this Agreement, (ii) such Guarantor (as opposed to its creditors, representatives of creditors or bankruptcy trustee, including such Guarantor in its capacity as debtor in possession exercising any powers of a bankruptcy trustee) has no personal right to enforce the limitation set forth in this Section 2(e) or to reduce, or request judicial relief reducing, the amount of its liability under this Agreement, and (iii) the limitation set forth in this Section 2(e) may be enforced only to the extent required under such laws in order for the obligations of such Guarantor under this Agreement to be enforceable under such laws and only by or for the benefit of a creditor, representative of creditors or bankruptcy trustee of such Guarantor or other Person entitled, under such laws, to enforce the provisions hereof.

3. Right of Contribution. Each Guarantor hereby agrees that to the extent that a Guarantor shall have paid more than its proportionate share of any payment made hereunder (including by way of set-off rights being exercised against it), such Guarantor shall be entitled to seek and receive contribution from and against any other Guarantor hereunder who has not paid its proportionate share of such payment as set forth in this Section 3. To the extent that any Guarantor shall be required hereunder to pay any portion of any Guaranteed Obligation guaranteed hereunder exceeding the greater of (a) the amount of the value actually received by such Guarantor and its Subsidiaries from such Guaranteed Obligation and (b) the amount such Guarantor would otherwise have paid if such Guarantor had paid the aggregate amount of such Guaranteed Obligation guaranteed hereunder (excluding the amount thereof repaid by the Issuer of such Guaranteed Obligation) in the same proportion as such Guarantor's net worth on the date enforcement is sought hereunder bears to the aggregate net worth of all the Guarantors on such date, then such Guarantor shall be reimbursed by such other Guarantors for the amount of such excess, pro rata, based on the respective net worth of such other Guarantors on such date; *provided* that any Guarantor's right of reimbursement shall be subject to the terms and conditions of Section 5 hereof. For purposes of determining the net worth of any Guarantor in connection with the foregoing, all Guarantees of such Guarantor other than pursuant to this Agreement will be deemed to be enforceable and payable after its obligations pursuant to this Agreement. The provisions of this Section 3 shall in no respect limit the obligations and liabilities of any Guarantor to the Guaranteed Parties, and each Guarantor shall remain liable to the Guaranteed Parties for the full amount guaranteed by such Guarantor hereunder.

4. No Right of Set-off. No Guaranteed Party shall have, as a result of this Agreement, any right of set-off against any amount owing by such Guaranteed Party to or for the credit or the account of a Guarantor.

5. No Subrogation. Notwithstanding any payment or payments made by any of the Guarantors hereunder, no Guarantor shall be entitled to be subrogated to any of the rights (or if subrogated by operation of law, such Guarantor hereby waives such rights to the extent permitted by applicable law) of any Guaranteed Party against any Issuer or any other Guarantor or any collateral security or guarantee or right of offset held by any Guaranteed Party for the payment of any Guaranteed Obligation, nor shall any Guarantor seek or be entitled to seek any contribution or reimbursement from any Issuer or any other Guarantor in respect of payments made by such Guarantor hereunder, until the Guarantee Termination Date. If any amount shall be paid to any Guarantor on account of such subrogation, contribution or reimbursement rights at any time prior to the Guarantee Termination Date, such amount shall be held by such Guarantor in trust for the applicable Guaranteed Parties, segregated from other funds of such Guarantor, and shall, forthwith upon receipt by such Guarantor, be turned over to the applicable Guaranteed Parties in the exact form received by such Guarantor (duly indorsed by such

Guarantor to the applicable Guaranteed Parties if required), to be applied against the applicable Guaranteed Obligation, whether due or to become due.

6. Amendments, etc. with Respect to the Guaranteed Obligations; Waiver of Rights; Release.

(a) Each Guarantor shall remain obligated hereunder notwithstanding that, without any reservation of rights against any Guarantor and without notice to or further assent by any Guarantor, (i) any demand for payment of any Guaranteed Obligation made by any Guaranteed Party may be rescinded by such party and any Guaranteed Obligation continued, (ii) a Guaranteed Obligation, or the liability of any other party upon or for any part thereof, or any collateral security or guarantee therefor or right of offset with respect thereto, may, from time to time, in whole or in part, be renewed, extended, amended, modified, accelerated, compromised, waived, allowed to lapse, surrendered or released by any Guaranteed Party, (iii) the instruments governing any Guaranteed Obligation may be amended, modified, supplemented or terminated, in whole or in part, and (iv) any collateral security, guarantee or right of offset at any time held by any Guaranteed Party for the payment of any Guaranteed Obligation may be sold, exchanged, waived, allowed to lapse, surrendered or released. No Guaranteed Party shall have any obligation to protect, secure, perfect or insure any Lien at any time held by it as security for the Guaranteed Obligations or for this Agreement or any property subject thereto. When making any demand hereunder against any Guarantor, a Guaranteed Party may, but shall be under no obligation to, make a similar demand on the Issuer of the applicable Guaranteed Obligation or any other Guarantor or any other person, and any failure by a Guaranteed Party to make any such demand or to collect any payments from such Issuer or any other Guarantor or any other person or any release of such Issuer or any other Guarantor or any other person shall not relieve any Guarantor in respect of which a demand or collection is not made or any Guarantor not so released of its several obligations or liabilities hereunder, and shall not impair or affect the rights and remedies, express or implied, or as a matter of law, of any Guaranteed Party against any Guarantor. For the purposes hereof "demand" shall include the commencement and continuance of any legal proceedings.

(b) A Guarantor shall be automatically released from its guarantee hereunder upon release of such Guarantor from the Revolving Credit Agreement Guarantee, including upon consummation of any transaction resulting in such Guarantor ceasing to constitute a Subsidiary or upon any Guarantor becoming an Excluded Subsidiary (such transaction or event, a "Release Event").

(c) Upon the occurrence of a Release Event, each Guaranteed Obligation for which such released Guarantor was the Issuer shall be automatically released from the provisions of this Agreement and shall cease to constitute a Guaranteed Obligation hereunder; *provided* that in the case of any Guaranteed Obligation that has been assigned an Investment Grade Rating by the Rating Agencies, such Guaranteed Obligation shall be so released, effective as of the 91st day after the occurrence of the Release Event, if and only if a Rating Decline with respect to such Guaranteed Obligation does not occur.

7. Guarantee Absolute and Unconditional.

(a) Each Guarantor waives any and all notice of the creation, contraction, incurrence, renewal, extension, amendment, waiver or accrual of any of the Guaranteed Obligations, and notice of or proof of reliance by any Guaranteed Party upon this Agreement or acceptance of this Agreement. To the fullest extent permitted by applicable law, each Guarantor waives diligence, promptness, presentment, protest and notice of protest, demand for payment or performance, notice of default or nonpayment, notice of acceptance and any other notice in respect of the Guaranteed Obligations or any part of them, and any defense arising by reason of any disability or other defense of any Issuer or any of the Guarantors with respect to the Guaranteed Obligations. Each Guarantor understands and agrees that this Agreement shall be construed as a continuing, absolute and unconditional guarantee of payment without regard to (i) the validity, regularity or enforceability of any of the Guaranteed Obligations, the indenture, loan agreement, note or other instrument evidencing or governing any of the Guaranteed Obligations or any collateral security therefor or guarantee or right of offset with respect thereto at any time or from time to time held by any Guaranteed Party, (ii) any defense, set-off or counterclaim (other than a defense of payment or performance) that may at any time be available to or be asserted by any Issuer against any Guaranteed Party or (iii) any other circumstance whatsoever (with or without notice to or knowledge of any Issuer or such Guarantor) that constitutes, or might be construed to constitute, an equitable or legal discharge of any Issuer for any of the Guaranteed Obligations, or of such Guarantor under this Agreement, in bankruptcy or in any other instance. When pursuing its rights and remedies hereunder against any Guarantor, any Guaranteed Party may, but shall be under no obligation to, pursue such rights and remedies as it may have against the Issuer or any other Person or against any collateral security or guarantee for the Guaranteed Obligations or any right of offset with respect thereto, and any failure by any Guaranteed Party to pursue such other rights or remedies or to collect any payments from the Issuer or any such other Person or to realize upon any such collateral security or guarantee or to exercise any such right of offset, or any release of the Issuer or any such other Person or any such collateral security, guarantee or right of offset, shall not relieve such Guarantor of any liability hereunder, and shall not impair or affect the rights and remedies, whether express, implied or available as a matter of law, of the other Guaranteed Parties against such Guarantor.

(b) This Agreement shall remain in full force and effect and be binding in accordance with and to the extent of its terms upon each Guarantor and the successors and assigns thereof and shall inure to the benefit of the Guaranteed Parties and their respective successors, indorsees, transferees and assigns until the Guarantee Termination Date.

8. Reinstatement. This Agreement shall continue to be effective, or be reinstated, as the case may be, if at any time payment, or any part thereof, of any of the Guaranteed Obligations is rescinded or must otherwise be restored or returned by any Guaranteed Party upon the insolvency, bankruptcy, dissolution, liquidation or reorganization of any Issuer or any Guarantor, or upon or as a result of the appointment of a receiver, intervenor or conservator of, or trustee or similar officer for, any Issuer or any Guarantor or any substantial part of its property, or otherwise, all as though such payments had not been made.

9. Payments. Each Guarantor hereby guarantees that payments hereunder will be paid to the applicable Guaranteed Parties without set-off or counterclaim in dollars.

10. Representations and Warranties. Each Guarantor hereby represents and warrants to each Guaranteed Party that the following representations and warranties are true and correct in all material respects as of the date of this Agreement or as of the date such Guarantor became a party to this Agreement, as applicable:

(a) such Guarantor (i) is a corporation, partnership or limited liability company duly organized or formed, validly existing and in good standing under the laws of the state of its incorporation, organization or formation, (ii) has all requisite corporate, partnership, limited liability company or other power and all material governmental licenses, authorizations, consents and approvals required to carry on its business as now conducted and (iii) is duly qualified to do business and is in good standing in every jurisdiction in which the failure to be so qualified would have a material adverse effect on its ability to perform its obligations under this Agreement;

(b) such Guarantor has all requisite corporate (or other organizational) power and authority to execute and deliver and to perform its obligations under this Agreement, and all such actions have been duly authorized by all necessary proceedings on its behalf;

(c) this Agreement has been duly and validly executed and delivered by or on behalf of such Guarantor and constitutes the valid and legally binding agreement of such Guarantor, enforceable against such Guarantor in accordance with its terms, except (i) as may be limited by bankruptcy, insolvency, reorganization, moratorium, fraudulent transfer, fraudulent conveyance or other similar laws relating to or affecting the enforcement of creditors' rights generally, and by general principles of equity (including principles of good faith, reasonableness, materiality and fair dealing) which may, among other things, limit the right to obtain equitable remedies (regardless of whether considered in a proceeding in equity or at law) and (ii) as to the enforceability of provisions for indemnification for violation of applicable securities laws, limitations thereon arising as a matter of law or public policy;

(d) no authorization, consent, approval, license or exemption of or registration, declaration or filing with any Governmental Authority is necessary for the valid execution and delivery of, or the performance by such Guarantor of its obligations hereunder, except those that have been obtained and such matters relating to performance as would ordinarily be done in the ordinary course of business after the date of this Agreement or as of the date such Guarantor became a party to this Agreement, as applicable; and

(e) neither the execution and delivery of, nor the performance by such Guarantor of its obligations under, this Agreement will (i) breach or violate any applicable Requirement of Law, (ii) result in any breach or violation of any of the terms, covenants, conditions or provisions of, or constitute a default under, or result in the creation or imposition of (or the obligation to create or impose) any Lien upon any of its property or assets (other than Liens created or contemplated by this Agreement) pursuant to the terms of, any indenture, mortgage, deed of trust, agreement or other instrument to which it or any of its Subsidiaries is party or by which any of its properties or assets, or those of any of its Subsidiaries is bound or to which it is subject, except for breaches, violations and defaults under clauses (i) and (ii) that neither individually nor in the aggregate could reasonably be expected to result in a material adverse effect on its ability to perform its obligations under this Agreement, or (iii) violate any provision of the organizational documents of such Guarantor.

11. Rights of Guaranteed Parties. Each Guarantor acknowledges and agrees that any changes in the identity of the Persons from time to time comprising the Guaranteed Parties gives rise to an equivalent change in the Guaranteed Parties, without any further act. Upon such an occurrence, the persons then comprising the Guaranteed Parties are vested with the rights, remedies and discretions of the Guaranteed Parties under this Agreement.

12. Notices.

(a) All notices, requests, demands and other communications to any Guarantor pursuant hereto shall be in writing and mailed, telecopied or delivered to such Guarantor in care of KMI, 1001 Louisiana Street, Suite 1000, Houston, Texas 77002, Attention: Treasurer, Telecopy: (713) 445-8302.

(b) KMI will provide a copy of this Agreement, including the most recently amended schedules and supplements hereto, to any Guaranteed Party upon written request to the address set forth in Section 12(a); *provided, however*, that KMI's obligations under this Section 12(b) shall be deemed satisfied if KMI has filed a copy of this Agreement, including the most recently amended schedules and supplements hereto, with the SEC within three months preceding the date on which KMI receives such written request.

13. Counterparts. This Agreement may be executed by one or more of the parties to this Agreement on any number of separate counterparts (including by facsimile or other electronic transmission), and all of said counterparts taken together shall be deemed to constitute one and the same instrument. A set of the copies of this Agreement signed by all the parties shall be lodged with KMI.

14. Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. The parties hereto shall endeavor in good-faith negotiations to replace the invalid, illegal or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the invalid, illegal or unenforceable provisions.

15. Integration. This Agreement represents the agreement of each Guarantor with respect to the subject matter hereof, and there are no promises, undertakings, representations or warranties by any Guaranteed Party relative to the subject matter hereof not expressly set forth or referred to herein.

16. Amendments; No Waiver; Cumulative Remedies.

(a) None of the terms or provisions of this Agreement may be waived, amended, supplemented or otherwise modified except by a written instrument executed by the affected Guarantors and KMI.

(b) The Guarantors may amend or supplement this Agreement by a written instrument executed by all Guarantors:

(i) to cure any ambiguity, defect or inconsistency;

(ii) to reflect a change in the Guarantors or the Guaranteed Obligations made in accordance with this Agreement;

(iii) to make any change that would provide any additional rights or benefits to the Guaranteed Parties or that would not adversely affect the legal rights hereunder of any Guaranteed Party in any material respect; or

(iv) to conform this Agreement to any change made to the Revolving Credit Agreement or to the Revolving Credit Agreement Guarantee.

Except as set forth in this clause (b) or otherwise provided herein, the Guarantors may not amend, supplement or otherwise modify this Agreement prior to the Guarantee Termination Date without the prior written consent of the holders of the majority of the outstanding principal amount of the Guaranteed Obligations (excluding obligations with respect to Hedging Agreements). Notwithstanding the foregoing, in the case of an amendment that would reasonably be expected to adversely, materially and disproportionately affect Guaranteed Parties with Guaranteed Obligations existing under Hedging Agreements relative to the other Guaranteed Parties, the foregoing exclusion of obligations with respect to Hedging Agreements shall not apply, and the outstanding principal amount attributable to each such Guaranteed Party's Guaranteed Obligations shall be deemed to be equal to the termination payment that would be due to such Guaranteed Party as if the valuation date were an "Early Termination Date" under and calculated in accordance with each applicable Hedging Agreement.

(c) No Guaranteed Party shall by any act, delay, indulgence, omission or otherwise be deemed to have waived any right or remedy hereunder or to have acquiesced in any breach of any of the terms and conditions hereof. No failure to exercise, nor any delay in exercising, on the part of any Guaranteed Party, any right, power or privilege hereunder shall operate as a waiver thereof. No single or partial exercise of any right, power or privilege hereunder shall preclude any other or further exercise thereof or the exercise of any other right, power or privilege. A waiver by a Guaranteed Party of any right or remedy hereunder on any one occasion shall not be construed as a bar to any right or remedy that such Guaranteed Party would otherwise have on any future occasion.

(d) The rights, remedies, powers and privileges herein provided are cumulative, may be exercised singly or concurrently and are not exclusive of any other rights or remedies provided by law.

17. Section Headings. The Section headings used in this Agreement are for convenience of reference only and are not to affect the construction hereof or be taken into consideration in the interpretation hereof.

18. Successors and Assigns. This Agreement shall be binding upon the successors and assigns of each Guarantor and shall inure to the benefit of the Guaranteed Parties and their respective successors and permitted assigns, except that no Guarantor may assign, transfer or delegate any of its rights or obligations under this Agreement except pursuant to a transaction permitted by the Revolving Credit Agreement and in connection with a corresponding assignment under the Revolving Credit Agreement Guarantee.

19. Additional Guarantors.

(a) KMI shall cause each Subsidiary (other than any Excluded Subsidiary) formed or otherwise purchased or acquired after the date of this Agreement (including each Subsidiary that ceases to constitute an Excluded Subsidiary after the date of this Agreement) to execute a supplement to this Agreement and become a Guarantor within 45 days of the occurrence of the applicable event specified in this Section 19(a).

(b) Each Subsidiary of KMI that becomes, at the request of KMI, or that is required pursuant to Section 19(a) to become, a party to this Agreement shall become a Guarantor, with the same force and effect as if originally named as a Guarantor herein, for all purposes of this Agreement upon execution and delivery by such Subsidiary of a written supplement substantially in the form of Annex A hereto. The execution and delivery of any instrument adding an additional Guarantor as a party to this Agreement shall not require the consent of any other Guarantor hereunder. The rights and obligations of each Guarantor hereunder shall remain in full force and effect notwithstanding the addition of any new Guarantor as a party to this Agreement.

20. Additional Guaranteed Obligations. Any Indebtedness issued by a Guarantor or for which a Guarantor otherwise becomes obligated after the date of this Agreement shall become a Guaranteed Obligation upon the execution by all Guarantors of a notation of guarantee substantially in the form of Annex B hereto, which shall be affixed to the instrument or instruments evidencing such Indebtedness. Each such notation of guarantee shall be signed on behalf of each Guarantor by a duly authorized officer prior to the authentication or issuance of such Indebtedness.

21. GOVERNING LAW. **THIS AGREEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.**

22. Keepwell. Each Qualified ECP Guarantor hereby jointly and severally absolutely, unconditionally and irrevocably undertakes to provide such funds or other support as may be needed from time to time by each other Guarantor to honor all of its obligations under this Agreement in respect of Swap Obligations (provided, however, that each Qualified ECP Guarantor shall only be liable under this Section 22 for the maximum amount of such liability that can be hereby incurred without rendering its obligations under this Section 22, or otherwise under this Agreement, voidable under applicable law relating to fraudulent conveyance or fraudulent transfer, and not for any greater amount). The obligations of each Qualified ECP Guarantor under this Section shall remain in full force and effect until the Guarantee Termination Date. Each Qualified ECP Guarantor intends that this Section 22 constitute, and this Section 22 shall be deemed to constitute, a "keepwell, support, or other agreement" for the benefit of each other Guarantor for all purposes of Section 1a(18)(A)(v)(II) of the Commodity Exchange Act.

[Signature pages follow]

IN WITNESS WHEREOF, each of the undersigned has caused this Agreement to be duly executed and delivered by its duly authorized officer or other representative as of the day and year first above written.

GUARANTORS

KINDER MORGAN, INC.

By: /s/ Anthony B. Ashley
Name: Anthony B. Ashley
Title: Treasurer

AGNES B CRANE, LLC
AMERICAN PETROLEUM TANKERS II LLC
AMERICAN PETROLEUM TANKERS III LLC
AMERICAN PETROLEUM TANKERS IV LLC
AMERICAN PETROLEUM TANKERS LLC
AMERICAN PETROLEUM TANKERS PARENT LLC
AMERICAN PETROLEUM TANKERS V LLC
AMERICAN PETROLEUM TANKERS VI LLC
AMERICAN PETROLEUM TANKERS VII LLC
APT FLORIDA LLC
APT INTERMEDIATE HOLDCO LLC
APT NEW INTERMEDIATE HOLDCO LLC
APT PENNSYLVANIA LLC
APT SUNSHINE STATE LLC
AUDREY TUG LLC
BEAR CREEK STORAGE COMPANY, L.L.C.
BETTY LOU LLC
CAMINO REAL GATHERING COMPANY, L.L.C.
CANTERA GAS COMPANY LLC
CDE PIPELINE LLC
CENTRAL FLORIDA PIPELINE LLC
CHEYENNE PLAINS GAS PIPELINE COMPANY, L.L.C.
CIG GAS STORAGE COMPANY LLC
CIG PIPELINE SERVICES COMPANY, L.L.C.
CIMMARRON GATHERING LLC
COLORADO INTERSTATE GAS COMPANY, L.L.C.
COLORADO INTERSTATE ISSUING CORPORATION
COPANO DOUBLE EAGLE LLC
COPANO ENERGY FINANCE CORPORATION
COPANO ENERGY, L.L.C.
COPANO ENERGY SERVICES/UPPER GULF COAST LLC
COPANO FIELD SERVICES GP, L.L.C.
COPANO FIELD SERVICES/NORTH TEXAS, L.L.C.
COPANO FIELD SERVICES/SOUTH TEXAS LLC
COPANO FIELD SERVICES/UPPER GULF COAST LLC
COPANO LIBERTY, LLC
COPANO NGL SERVICES (MARKHAM), L.L.C.
COPANO NGL SERVICES LLC
COPANO PIPELINES GROUP, L.L.C.

COPANO PIPELINES/NORTH TEXAS, L.L.C.
COPANO PIPELINES/ROCKY MOUNTAINS, LLC
COPANO PIPELINES/SOUTH TEXAS LLC
COPANO PIPELINES/UPPER GULF COAST LLC
COPANO PROCESSING LLC
COPANO RISK MANAGEMENT LLC
COPANO/WEBB-DUVAL PIPELINE LLC
CPNO SERVICES LLC
DAKOTA BULK TERMINAL, INC.
DELTA TERMINAL SERVICES LLC
EAGLE FORD GATHERING LLC
EL PASO CHEYENNE HOLDINGS, L.L.C.
EL PASO CITRUS HOLDINGS, INC.
EL PASO CNG COMPANY, L.L.C.
EL PASO ENERGY SERVICE COMPANY, L.L.C.
EL PASO LLC
EL PASO MIDSTREAM GROUP LLC
EL PASO NATURAL GAS COMPANY, L.L.C.
EL PASO NORIC INVESTMENTS III, L.L.C.
EL PASO PIPELINE CORPORATION
EL PASO PIPELINE GP COMPANY, L.L.C.
EL PASO PIPELINE HOLDING COMPANY, L.L.C.
EL PASO PIPELINE LP HOLDINGS, L.L.C.
EL PASO PIPELINE PARTNERS, L.P.
By El Paso Pipeline GP Company, L.L.C., its general partner
EL PASO PIPELINE PARTNERS OPERATING COMPANY, L.L.C.
EL PASO RUBY HOLDING COMPANY, L.L.C.
EL PASO TENNESSEE PIPELINE CO., L.L.C.
ELBA EXPRESS COMPANY, L.L.C.
ELIZABETH RIVER TERMINALS LLC
EMORY B CRANE, LLC
EPBGP CONTRACTING SERVICES LLC
EP ENERGY HOLDING COMPANY
EP RUBY LLC
EPTP ISSUING CORPORATION
FERNANDINA MARINE CONSTRUCTION MANAGEMENT LLC
FRANK L. CRANE, LLC
GENERAL STEVEDORES GP, LLC
GENERAL STEVEDORES HOLDINGS LLC
GLOBAL AMERICAN TERMINALS LLC
HAMPSHIRE LLC
HARRAH MIDSTREAM LLC
HBM ENVIRONMENTAL, INC.
ICPT, L.L.C
J.R. NICHOLLS LLC
JAVELINA TUG LLC
JEANNIE BREWER LLC
JV TANKER CHARTERER LLC
KINDER MORGAN (DELAWARE), INC.
KINDER MORGAN 2-MILE LLC
KINDER MORGAN ADMINISTRATIVE SERVICES TAMPA LLC
KINDER MORGAN ALTAMONT LLC

KINDER MORGAN AMORY LLC
KINDER MORGAN ARROW TERMINALS HOLDINGS, INC.
KINDER MORGAN ARROW TERMINALS, L.P.
By Kinder Morgan River Terminals, LLC, its general partner
KINDER MORGAN BALTIMORE TRANSLOAD TERMINAL LLC
KINDER MORGAN BATTLEGROUND OIL LLC
KINDER MORGAN BORDER PIPELINE LLC
KINDER MORGAN BULK TERMINALS, INC.
KINDER MORGAN CARBON DIOXIDE TRANSPORTATION COMPANY
KINDER MORGAN CO2 COMPANY, L.P.
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN COCHIN LLC
KINDER MORGAN COLUMBUS LLC
KINDER MORGAN COMMERCIAL SERVICES LLC
KINDER MORGAN CRUDE & CONDENSATE LLC
KINDER MORGAN CRUDE OIL PIPELINES LLC
KINDER MORGAN CRUDE TO RAIL LLC
KINDER MORGAN CUSHING LLC
KINDER MORGAN DALLAS FORT WORTH RAIL TERMINAL LLC
KINDER MORGAN ENDEAVOR LLC
KINDER MORGAN ENERGY PARTNERS, L.P.
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN EP MIDSTREAM LLC
KINDER MORGAN FINANCE COMPANY LLC
KINDER MORGAN FLEETING LLC
KINDER MORGAN FREEDOM PIPELINE LLC
KINDER MORGAN KEYSTONE GAS STORAGE LLC
KINDER MORGAN KMAP LLC
KINDER MORGAN LAS VEGAS LLC
KINDER MORGAN LINDEN TRANSLOAD TERMINAL LLC
KINDER MORGAN LIQUIDS TERMINALS LLC
KINDER MORGAN LIQUIDS TERMINALS ST. GABRIEL LLC
KINDER MORGAN MARINE SERVICES LLC
KINDER MORGAN MATERIALS SERVICES, LLC
KINDER MORGAN MID ATLANTIC MARINE SERVICES LLC
KINDER MORGAN NATGAS O&M LLC
KINDER MORGAN NORTH TEXAS PIPELINE LLC
KINDER MORGAN OPERATING L.P. “A”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN OPERATING L.P. “B”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN OPERATING L.P. “C”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN OPERATING L.P. “D”
By Kinder Morgan G.P., Inc., its general partner
KINDER MORGAN PECOS LLC
KINDER MORGAN PECOS VALLEY LLC
KINDER MORGAN PETCOKE GP LLC

KINDER MORGAN PETCOKE, L.P.
By Kinder Morgan Petcoke GP LLC, its general partner
KINDER MORGAN PETCOKE LP LLC
KINDER MORGAN PETROLEUM TANKERS LLC
KINDER MORGAN PIPELINE LLC
KINDER MORGAN PIPELINES (USA) INC.
KINDER MORGAN PORT MANATEE TERMINAL LLC
KINDER MORGAN PORT SUTTON TERMINAL LLC
KINDER MORGAN PORT TERMINALS USA LLC
KINDER MORGAN PRODUCTION COMPANY LLC
KINDER MORGAN RAIL SERVICES LLC
KINDER MORGAN RESOURCES II LLC
KINDER MORGAN RESOURCES III LLC
KINDER MORGAN RESOURCES LLC
KINDER MORGAN RIVER TERMINALS LLC
KINDER MORGAN SERVICES LLC
KINDER MORGAN SEVEN OAKS LLC
KINDER MORGAN SOUTHEAST TERMINALS LLC
KINDER MORGAN TANK STORAGE TERMINALS LLC
KINDER MORGAN TEJAS PIPELINE LLC
KINDER MORGAN TERMINALS, INC.
KINDER MORGAN TEXAS PIPELINE LLC
KINDER MORGAN TEXAS TERMINALS, L.P.
By General Stevedores GP, LLC, its general partner
KINDER MORGAN TRANSMIX COMPANY, LLC
KINDER MORGAN TREATING LP
By KM Treating GP LLC, its general partner
KINDER MORGAN URBAN RENEWAL, L.L.C.
KINDER MORGAN UTICA LLC
KINDER MORGAN VIRGINIA LIQUIDS TERMINALS LLC
KINDER MORGAN WINK PIPELINE LLC
KINDERHAWK FIELD SERVICES LLC
KM CRANE LLC
KM DECATUR, INC.
KM EAGLE GATHERING LLC
KM GATHERING LLC
KM KASKASKIA DOCK LLC
KM LIQUIDS TERMINALS LLC
KM NORTH CAHOKIA LAND LLC
KM NORTH CAHOKIA SPECIAL PROJECT LLC
KM NORTH CAHOKIA TERMINAL PROJECT LLC
KM SHIP CHANNEL SERVICES LLC
KM TREATING GP LLC
KM TREATING PRODUCTION LLC
KMBT LLC
KMGP CONTRACTING SERVICES LLC
KMGP SERVICES COMPANY, INC.
KN TELECOMMUNICATIONS, INC.
KNIGHT POWER COMPANY LLC
LOMITA RAIL TERMINAL LLC
MILWAUKEE BULK TERMINALS LLC
MJR OPERATING LLC
MOJAVE PIPELINE COMPANY, L.L.C.
MOJAVE PIPELINE OPERATING COMPANY, L.L.C.
MR. BENNETT LLC

MR. VANCE LLC
NASSAU TERMINALS LLC
NGPL HOLDCO INC.
NS 307 HOLDINGS INC.
PADDY RYAN CRANE, LLC
PALMETTO PRODUCTS PIPE LINE LLC
PI 2 PELICAN STATE LLC
PINNEY DOCK & TRANSPORT LLC
QUEEN CITY TERMINALS LLC
RAHWAY RIVER LAND LLC
RAZORBACK TUG LLC
RCI HOLDINGS, INC.
RIVER TERMINALS PROPERTIES GP LLC
RIVER TERMINAL PROPERTIES, L.P.
By River Terminals Properties GP LLC, its general partner
SCISSORTAIL ENERGY, LLC
SNG PIPELINE SERVICES COMPANY, L.L.C.
SOUTHERN GULF LNG COMPANY, L.L.C.
SOUTHERN LIQUEFACTION COMPANY LLC
SOUTHERN LNG COMPANY, L.L.C.
SOUTHERN NATURAL GAS COMPANY, L.L.C.
SOUTHERN NATURAL ISSUING CORPORATION
SOUTHTEX TREATERS LLC
SOUTHWEST FLORIDA PIPELINE LLC
SRT VESSELS LLC
STEVEDORE HOLDINGS, L.P.
By Kinder Morgan Petcoke GP LLC, its general partner
TAJON HOLDINGS, INC.
TEJAS GAS, LLC
TEJAS NATURAL GAS, LLC
TENNESSEE GAS PIPELINE COMPANY, L.L.C.
TENNESSEE GAS PIPELINE ISSUING CORPORATION
TEXAN TUG LLC
TGP PIPELINE SERVICES COMPANY, L.L.C.
TRANS MOUNTAIN PIPELINE (PUGET SOUND) LLC
TRANSCOLORADO GAS TRANSMISSION COMPANY LLC
TRANSLOAD SERVICES, LLC
UTICA MARCELLUS TEXAS PIPELINE LLC
WESTERN PLANT SERVICES, INC.
WYOMING INTERSTATE COMPANY, L.L.C.

By: /s/ Anthony B. Ashley
Anthony Ashley
Vice President

Exhibit 10.14

ANNEX A TO
THE CROSS GUARANTEE AGREEMENT

SUPPLEMENT NO. [ ] dated as of [ ] to the CROSS GUARANTEE AGREEMENT dated as of [ ] (the "Agreement"), among each of the Guarantors listed on the signature pages thereto and each of the other entities that becomes a party thereto pursuant to Section 19 of the Agreement (each such entity individually, a "Guarantor" and, collectively, the "Guarantors"). Unless otherwise defined herein, terms defined in the Agreement and used herein shall have the meanings given to them in the Agreement.

A. The Guarantors consist of Kinder Morgan, Inc., a Delaware corporation ("KMI"), and certain of its direct and indirect Subsidiaries, and the Guarantors have entered into the Agreement in order to provide guarantees of certain of the Guarantors' senior, unsecured Indebtedness outstanding from time to time.

B. Section 19 of the Agreement provides that additional Subsidiaries may become Guarantors under the Agreement by execution and delivery of an instrument in the form of this Supplement. Each undersigned Subsidiary (each a "New Guarantor") is executing this Supplement at the request of KMI or in accordance with the requirements of the Agreement to become a Guarantor under the Agreement.

Accordingly, each New Guarantor agrees as follows:

SECTION 1. In accordance with Section 19 of the Agreement, each New Guarantor by its signature below becomes a Guarantor under the Agreement with the same force and effect as if originally named therein as a Guarantor and each New Guarantor hereby (a) agrees to all the terms and provisions of the Agreement applicable to it as a Guarantor thereunder and (b) represents and warrants that the representations and warranties made by it as a Guarantor thereunder are true and correct on and as of the date hereof. Each reference to a Guarantor in the Agreement shall be deemed to include each New Guarantor. The Agreement is hereby incorporated herein by reference.

SECTION 2. Each New Guarantor represents and warrants to the Guaranteed Parties that this Supplement has been duly authorized, executed and delivered by it and constitutes its legal, valid and binding obligation, enforceable against it in accordance with its terms.

SECTION 3. This Supplement may be executed by one or more of the parties to this Supplement on any number of separate counterparts (including by facsimile or other electronic transmission), and all of said counterparts taken together shall be deemed to constitute one and the same instrument. A set of the copies of this Supplement signed by all the parties shall be lodged with KMI. This Supplement shall become effective as to each New Guarantor when KMI shall have received a counterpart of this Supplement that bears the signature of such New Guarantor.

SECTION 4. Except as expressly supplemented hereby, the Agreement shall remain in full force and effect.

SECTION 5. THIS SUPPLEMENT AND THE RIGHTS AND OBLIGATIONS OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY, AND CONSTRUED AND INTERPRETED IN ACCORDANCE WITH, THE LAW OF THE STATE OF NEW YORK.

SECTION 6. Any provision of this Supplement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof and in the Agreement, and any such prohibition or unenforceability in any jurisdiction shall not invalidate or render unenforceable such provision in any other jurisdiction. The parties hereto shall endeavor in good-faith negotiations to replace the invalid, illegal or unenforceable provisions with valid provisions the economic effect of which comes as close as possible to that of the invalid, illegal or unenforceable provisions.

SECTION 7. All notices, requests and demands pursuant hereto shall be made in accordance with Section 12 of the Agreement. All communications and notices hereunder to each New Guarantor shall be given to it in care of KMI at the address set forth in Section 12 of the Agreement.

[Signature Pages Follow]

IN WITNESS WHEREOF, each New Guarantor has duly executed this Supplement to the Agreement as of the day and year first above written.

____
as Guarantor

By:______________________________
Name:
Title:

Exhibit 10.14

ANNEX B TO
THE CROSS GUARANTEE AGREEMENT

FORM OF NOTATION OF GUARANTEE

Subject to the limitations set forth in the Cross Guarantee Agreement, dated as of [•] (the "Guarantee Agreement"), the undersigned Guarantors hereby certify that this [Indebtedness] constitutes a Guaranteed Obligation, entitled to all the rights as such set forth in the Guarantee Agreement. The Guarantors may be released from their guarantees upon the terms and subject to the conditions provided in the Guarantee Agreement. Capitalized terms used but not defined in this notation of guarantee have the meanings assigned such terms in the Guarantee Agreement, a copy of which will be provided to [a holder of this instrument] upon request to [Issuer].

Schedule I of the Guarantee Agreement is hereby deemed to be automatically updated to include this [Indebtedness] thereon as a Guaranteed Obligation.

[GUARANTORS],
as Guarantor

By: ______________________________
Name:
Title:

Exhibit 10.14

SCHEDULE I

Guaranteed Obligations
Current as of: December 31, 2020

Issuer	**Indebtedness**	**Maturity**
Kinder Morgan, Inc.	5.00% notes	February 15, 2021
Kinder Morgan, Inc.	1.500% notes	March 16, 2022
Kinder Morgan, Inc.	3.150% bonds	January 15, 2023
Kinder Morgan, Inc.	Floating rate bonds	January 15, 2023
Kinder Morgan, Inc.	5.625% notes	November 15, 2023
Kinder Morgan, Inc.	4.30% notes	June 1, 2025
Kinder Morgan, Inc.	6.70% bonds (Coastal)	February 15, 2027
Kinder Morgan, Inc.	2.250% notes	March 16, 2027
Kinder Morgan, Inc.	6.67% debentures	November 1, 2027
Kinder Morgan, Inc.	7.25% debentures	March 1, 2028
Kinder Morgan, Inc.	4.30% notes	March 1, 2028
Kinder Morgan, Inc.	6.95% bonds (Coastal)	June 1, 2028
Kinder Morgan, Inc.	8.05% bonds	October 15, 2030
Kinder Morgan, Inc.	2.00% notes	February 15, 2031
Kinder Morgan, Inc.	7.80% bonds	August 1, 2031
Kinder Morgan, Inc.	7.75% bonds	January 15, 2032
Kinder Morgan, Inc.	5.30% notes	December 1, 2034
Kinder Morgan, Inc.	7.75% bonds (Coastal)	October 15, 2035
Kinder Morgan, Inc.	6.40% notes	January 5, 2036
Kinder Morgan, Inc.	7.42% bonds (Coastal)	February 15, 2037
Kinder Morgan, Inc.	5.55% notes	June 1, 2045
Kinder Morgan, Inc.	5.050% notes	February 15, 2046
Kinder Morgan, Inc.	5.20% notes	March 1, 2048
Kinder Morgan, Inc.	3.25% notes	August 1, 2050
Kinder Morgan, Inc.	7.45% debentures	March 1, 2098
Kinder Morgan, Inc.	$100 Million Letter of Credit Facility	November 30, 2020
Kinder Morgan Energy Partners, L.P.	5.80% bonds	March 1, 2021
Kinder Morgan Energy Partners, L.P.	3.50% bonds	March 1, 2021
Kinder Morgan Energy Partners, L.P.	4.15% bonds	March 1, 2022
Kinder Morgan Energy Partners, L.P.	3.95% bonds	September 1, 2022
Kinder Morgan Energy Partners, L.P.	3.45% bonds	February 15, 2023
Kinder Morgan Energy Partners, L.P.	3.50% bonds	September 1, 2023
Kinder Morgan Energy Partners, L.P.	4.15% bonds	February 1, 2024
Kinder Morgan Energy Partners, L.P.	4.25% bonds	September 1, 2024
Kinder Morgan Energy Partners, L.P.	7.40% bonds	March 15, 2031
Kinder Morgan Energy Partners, L.P.	7.75% bonds	March 15, 2032
Kinder Morgan Energy Partners, L.P.	7.30% bonds	August 15, 2033
Kinder Morgan Energy Partners, L.P.	5.80% bonds	March 15, 2035
Kinder Morgan Energy Partners, L.P.	6.50% bonds	February 1, 2037
Kinder Morgan Energy Partners, L.P.	6.95% bonds	January 15, 2038
Kinder Morgan Energy Partners, L.P.	6.50% bonds	September 1, 2039

Schedule I
(Guaranteed Obligations)
Current as of: December 31, 2020

Issuer	Indebtedness	Maturity
Kinder Morgan Energy Partners, L.P.	6.55% bonds	September 15, 2040
Kinder Morgan Energy Partners, L.P.	6.375% bonds	March 1, 2041
Kinder Morgan Energy Partners, L.P.	5.625% bonds	September 1, 2041
Kinder Morgan Energy Partners, L.P.	5.00% bonds	August 15, 2042
Kinder Morgan Energy Partners, L.P.	5.00% bonds	March 1, 2043
Kinder Morgan Energy Partners, L.P.	5.50% bonds	March 1, 2044
Kinder Morgan Energy Partners, L.P.	5.40% bonds	September 1, 2044
Kinder Morgan Energy Partners, L.P.(1)	5.00% bonds	October 1, 2021
Kinder Morgan Energy Partners, L.P.(1)	4.30% bonds	May 1, 2024
Kinder Morgan Energy Partners, L.P.(1)	7.50% bonds	November 15, 2040
Kinder Morgan Energy Partners, L.P.(1)	4.70% bonds	November 1, 2042
Tennessee Gas Pipeline Company, L.L.C.	7.00% bonds	March 15, 2027
Tennessee Gas Pipeline Company, L.L.C.	7.00% bonds	October 15, 2028
Tennessee Gas Pipeline Company, L.L.C.	2.90% bonds	March 1, 2030
Tennessee Gas Pipeline Company, L.L.C.	8.375% bonds	June 15, 2032
Tennessee Gas Pipeline Company, L.L.C.	7.625% bonds	April 1, 2037
El Paso Natural Gas Company, L.L.C.	8.625% bonds	January 15, 2022
El Paso Natural Gas Company, L.L.C.	7.50% bonds	November 15, 2026
El Paso Natural Gas Company, L.L.C.	8.375% bonds	June 15, 2032
Colorado Interstate Gas Company, L.L.C.	4.15% notes	August 15, 2026
Colorado Interstate Gas Company, L.L.C.	6.85% bonds	June 15, 2037
El Paso Tennessee Pipeline Co. L.L.C.	7.25% bonds	December 15, 2025
Other	Cora industrial revenue bonds	April 1, 2024

(1) The original issuer, El Paso Pipeline Partners, L.P. merged with and into Kinder Morgan Energy Partners, L.P. effective January 1, 2015.

Schedule I
(Guaranteed Obligations)
Current as of: December 31, 2020

Hedging Agreements[1]

Issuer	Guaranteed Party	Date
Kinder Morgan, Inc.	Bank of America, N.A.	January 4, 2018
Kinder Morgan, Inc.	BNP Paribas	September 15, 2016
Kinder Morgan, Inc.	Citibank, N.A.	March 16, 2017
Kinder Morgan, Inc.	J. Aron & Company	December 23, 2011
Kinder Morgan, Inc.	SunTrust Bank	August 29, 2001
Kinder Morgan, Inc.	Barclays Bank PLC	November 26, 2014
Kinder Morgan, Inc.	Bank of Montreal	April 25, 2019
Kinder Morgan, Inc.	Bank of Tokyo-Mitsubishi, Ltd., New York Branch	November 26, 2014
Kinder Morgan, Inc.	Canadian Imperial Bank of Commerce	November 26, 2014
Kinder Morgan, Inc.	Commerzbank AG	August 22, 2019
Kinder Morgan, Inc.	Compass Bank	March 24, 2015
Kinder Morgan, Inc.	Credit Agricole Corporate and Investment Bank	November 26, 2014
Kinder Morgan, Inc.	Credit Suisse International	November 26, 2014
Kinder Morgan, Inc.	Deutsche Bank AG	November 26, 2014
Kinder Morgan, Inc.	ING Capital Markets LLC	November 26, 2014
Kinder Morgan, Inc.	Intesa Sanpaolo S.p.A.	July 1, 2019
Kinder Morgan, Inc.	JPMorgan Chase Bank, N.A.	February 19, 2015
Kinder Morgan, Inc.	Mizuho Capital Markets Corporation	November 26, 2014
Kinder Morgan, Inc.	Morgan Stanley Capital Services LLC	July 9, 2018
Kinder Morgan, Inc.	PNC Bank National Association	February 4, 2019
Kinder Morgan, Inc.	Royal Bank of Canada	November 26, 2014
Kinder Morgan, Inc.	SMBC Capital Markets, Inc.	April 26, 2017
Kinder Morgan, Inc.	The Bank of Nova Scotia	November 26, 2014
Kinder Morgan, Inc.	The Royal Bank of Scotland PLC	November 26, 2014
Kinder Morgan, Inc.	Societe Generale	November 26, 2014
Kinder Morgan, Inc.	The Toronto-Dominion Bank	October 2, 2017
Kinder Morgan, Inc.	UBS AG	November 26, 2014
Kinder Morgan, Inc.	Wells Fargo Bank, N.A.	November 26, 2014
Kinder Morgan Energy Partners, L.P.	Bank of America, N.A.	April 14, 1999
Kinder Morgan Energy Partners, L.P.	Bank of Tokyo-Mitsubishi, Ltd., New York Branch	November 23, 2004
Kinder Morgan Energy Partners, L.P.	Barclays Bank PLC	November 18, 2003
Kinder Morgan Energy Partners, L.P.	Canadian Imperial Bank of Commerce	August 4, 2011
Kinder Morgan Energy Partners, L.P.	Citibank, N.A.	March 14, 2002
Kinder Morgan Energy Partners, L.P.	Credit Agricole Corporate and Investment Bank	June 20, 2014
Kinder Morgan Energy Partners, L.P.	Credit Suisse International	May 14, 2010

[1] Guaranteed Obligations with respect to Hedging Agreements include International Swaps and Derivatives Association Master Agreements (“ISDAs”) and all transactions entered into pursuant to any ISDA listed on this Schedule I.

Exhibit 10.14

Schedule I
(Guaranteed Obligations)
Current as of: December 31, 2020

Hedging Agreements[1]

Issuer	Guaranteed Party	Date
Kinder Morgan Energy Partners, L.P.	Deutsche Bank AG	April 2, 2009
Kinder Morgan Energy Partners, L.P.	ING Capital Markets LLC	September 21, 2011
Kinder Morgan Energy Partners, L.P.	J. Aron & Company	November 11, 2004
Kinder Morgan Energy Partners, L.P.	JPMorgan Chase Bank	August 29, 2001
Kinder Morgan Energy Partners, L.P.	Mizuho Capital Markets Corporation	July 11, 2014
Kinder Morgan Energy Partners, L.P.	Morgan Stanley Capital Services Inc.	March 10, 2010
Kinder Morgan Energy Partners, L.P.	Royal Bank of Canada	March 12, 2009
Kinder Morgan Energy Partners, L.P.	The Royal Bank of Scotland PLC	March 20, 2009
Kinder Morgan Energy Partners, L.P.	The Bank of Nova Scotia	August 14, 2003
Kinder Morgan Energy Partners, L.P.	Societe Generale	July 18, 2014
Kinder Morgan Energy Partners, L.P.	SunTrust Bank	March 14, 2002
Kinder Morgan Energy Partners, L.P.	UBS AG	February 23, 2011
Kinder Morgan Energy Partners, L.P.	Wells Fargo Bank, N.A.	July 31, 2007
Kinder Morgan Texas Pipeline LLC	Bank of Montreal	April 25, 2019
Kinder Morgan Texas Pipeline LLC	Barclays Bank PLC	January 10, 2003
Kinder Morgan Texas Pipeline LLC	BNP Paribas	March 2, 2005
Kinder Morgan Texas Pipeline LLC	Canadian Imperial Bank of Commerce	December 18, 2006
Kinder Morgan Texas Pipeline LLC	Citibank, N.A.	February 22, 2005
Kinder Morgan Texas Pipeline LLC	Credit Suisse International	August 31, 2012
Kinder Morgan Texas Pipeline LLC	Deutsche Bank AG	June 13, 2007
Kinder Morgan Texas Pipeline LLC	ING Capital Markets LLC	April 17, 2014
Kinder Morgan Production LLC	J. Aron & Company	June 12, 2006
Kinder Morgan Texas Pipeline LLC	J. Aron & Company	June 8, 2000
Kinder Morgan Texas Pipeline LLC	JPMorgan Chase Bank, N.A.	September 7, 2006
Kinder Morgan Texas Pipeline LLC	Macquarie Bank Limited	September 20, 2010
Kinder Morgan Texas Pipeline LLC	Merrill Lynch Commodities, Inc.	October 24, 2001
Kinder Morgan Texas Pipeline LLC	Natixis	June 13, 2011
Kinder Morgan Texas Pipeline LLC	Phillips 66 Company	March 30, 2015
Kinder Morgan Texas Pipeline LLC	PNC Bank, National Association	July 11, 2018
Kinder Morgan Texas Pipeline LLC	Royal Bank of Canada	October 18, 2018
Kinder Morgan Texas Pipeline LLC	The Bank of Nova Scotia	May 8, 2014
Kinder Morgan Texas Pipeline LLC	Societe Generale	January 14, 2003
Kinder Morgan Texas Pipeline LLC	Wells Fargo Bank, N.A.	June 1, 2013
Copano Risk Management, LLC	Citibank, N.A.	July 21, 2008
Copano Risk Management, LLC	J. Aron & Company	December 12, 2005
Copano Risk Management, LLC	Morgan Stanley Capital Group Inc.	May 4, 2007

[1] Guaranteed Obligations with respect to Hedging Agreements include International Swaps and Derivatives Association Master Agreements (“ISDAs”) and all transactions entered into pursuant to any ISDA listed on this Schedule I.

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SCHEDULE II

Guarantors
Current as of: December 31, 2020

Agnes B Crane, LLC
American Petroleum Tankers II LLC
American Petroleum Tankers III LLC
American Petroleum Tankers IV LLC
American Petroleum Tankers LLC
American Petroleum Tankers Parent LLC
American Petroleum Tankers V LLC
American Petroleum Tankers VI LLC
American Petroleum Tankers VII LLC
American Petroleum Tankers VIII LLC
American Petroleum Tankers IX LLC
American Petroleum Tankers X LLC
American Petroleum Tankers XI LLC
APT Florida LLC
APT Intermediate Holdco LLC
APT New Intermediate Holdco LLC
APT Pennsylvania LLC
APT Sunshine State LLC
Betty Lou LLC
Camino Real Gas Gathering Company LLC
Camino Real Gathering Company, L.L.C.
Cantera Gas Company LLC
CDE Pipeline LLC
Central Florida Pipeline LLC
Cheyenne Plains Gas Pipeline Company, L.L.C.
CIG Gas Storage Company LLC
CIG Pipeline Services Company, L.L.C.
Colorado Interstate Gas Company, L.L.C.
Colorado Interstate Issuing Corporation
Copano Double Eagle LLC
Copano Energy Finance Corporation
Copano Energy Services/Upper Gulf Coast LLC
Copano Energy, L.L.C.
Copano Field Services GP, L.L.C.
Copano Field Services/North Texas, L.L.C.
Copano Field Services/South Texas LLC
Copano Field Services/Upper Gulf Coast LLC
Copano Liberty, LLC
Copano Liquids Marketing LLC
Copano NGL Services (Markham), L.L.C.
Copano NGL Services LLC
Copano Pipelines Group, L.L.C.
Copano Pipelines/North Texas, L.L.C.
Copano Pipelines/Rocky Mountains, LLC
Copano Pipelines/South Texas LLC
Copano Pipelines/Upper Gulf Coast LLC
Copano Processing LLC
Copano Risk Management LLC
Copano Terminals LLC
Copano/Webb-Duval Pipeline LLC
CPNO Services LLC
Dakota Bulk Terminal LLC
Delta Terminal Services LLC
Eagle Ford Gathering LLC
El Paso Cheyenne Holdings, L.L.C.
El Paso Citrus Holdings, Inc.
El Paso CNG Company, L.L.C.
El Paso Energy Service Company, L.L.C.
El Paso LLC
El Paso Midstream Group LLC
El Paso Natural Gas Company, L.L.C.
El Paso Noric Investments III, L.L.C.
El Paso Ruby Holding Company, L.L.C.
El Paso Tennessee Pipeline Co., L.L.C.
Elba Express Company, L.L.C.
Elizabeth River Terminals LLC
Emory B Crane, LLC
EP Ruby LLC
EPBGP Contracting Services LLC
EPTP Issuing Corporation
Frank L. Crane, LLC
General Stevedores GP, LLC
General Stevedores Holdings LLC
Harrah Midstream LLC
HBM Environmental LLC
Hiland Crude, LLC
Hiland Partners Holdings LLC
HPH Oklahoma Gathering LLC
ICPT, L.L.C
Independent Trading & Transportation Company I, L.L.C.
JV Tanker Charterer LLC
Kinder Morgan 2-Mile LLC
Kinder Morgan Administrative Services Tampa LLC
Kinder Morgan Altamont LLC
Kinder Morgan Baltimore Transload Terminal LLC
Kinder Morgan Battleground Oil LLC
Kinder Morgan Border Pipeline LLC
Kinder Morgan Bulk Terminals LLC
Kinder Morgan Carbon Dioxide Transportation Company
Kinder Morgan CO2 Company LLC
Kinder Morgan Commercial Services LLC

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Schedule II
(Guarantors)
Current as of: December 31, 2020

Kinder Morgan Contracting Services LLC
Kinder Morgan Crude & Condensate LLC
Kinder Morgan Crude Marketing LLC
Kinder Morgan Crude Oil Pipelines LLC
Kinder Morgan Crude to Rail LLC
Kinder Morgan Cushing LLC
Kinder Morgan Dallas Fort Worth Rail Terminal LLC
Kinder Morgan Deeprock North Holdco LLC
Kinder Morgan Endeavor LLC
Kinder Morgan Energy Partners, L.P.
Kinder Morgan EP Midstream LLC
Kinder Morgan Finance Company LLC
Kinder Morgan Freedom Pipeline LLC
Kinder Morgan Galena Park West LLC
Kinder Morgan IMT Holdco LLC
Kinder Morgan, Inc.
Kinder Morgan Keystone Gas Storage LLC
Kinder Morgan KMAP LLC
Kinder Morgan Las Vegas LLC
Kinder Morgan Linden Transload Terminal LLC
Kinder Morgan Liquids Terminals LLC
Kinder Morgan Liquids Terminals St. Gabriel LLC
Kinder Morgan Louisiana Pipeline Holding LLC
Kinder Morgan Louisiana Pipeline LLC
Kinder Morgan Marine Services LLC
Kinder Morgan Materials Services, LLC
Kinder Morgan Mid Atlantic Marine Services LLC
Kinder Morgan NatGas O&M LLC
Kinder Morgan NGPL Holdings LLC
Kinder Morgan North Texas Pipeline LLC
Kinder Morgan Operating LLC “A”
Kinder Morgan Operating LLC “B”
Kinder Morgan Operating LLC “C”
Kinder Morgan Operating LLC “D”
Kinder Morgan Pecos LLC
Kinder Morgan Pecos Valley LLC
Kinder Morgan Petcoke GP LLC
Kinder Morgan Petcoke LP LLC
Kinder Morgan Petcoke, L.P.
Kinder Morgan Petroleum Tankers LLC
Kinder Morgan Pipeline LLC
Kinder Morgan Port Manatee Terminal LLC
Kinder Morgan Port Sutton Terminal LLC
Kinder Morgan Port Terminals USA LLC
Kinder Morgan Portland Jet Line LLC
Kinder Morgan Production Company LLC
Kinder Morgan Products Terminals LLC
Kinder Morgan Rail Services LLC
Kinder Morgan Resources II LLC
Kinder Morgan Resources III LLC
Kinder Morgan Resources LLC
Kinder Morgan Seven Oaks LLC
Kinder Morgan SNG Operator LLC
Kinder Morgan Southeast Terminals LLC
Kinder Morgan Scurry Connector LLC
Kinder Morgan Tank Storage Terminals LLC
Kinder Morgan Tejas Pipeline LLC
Kinder Morgan Terminals, Inc.
Kinder Morgan Terminals Wilmington LLC
Kinder Morgan Texas Pipeline LLC
Kinder Morgan Texas Terminals, L.P.
Kinder Morgan Transmix Company, LLC
Kinder Morgan Treating LP
Kinder Morgan Urban Renewal, L.L.C.
Kinder Morgan Utica LLC
Kinder Morgan Vehicle Services LLC
Kinder Morgan Virginia Liquids Terminals LLC
Kinder Morgan Wink Pipeline LLC
KinderHawk Field Services LLC
KM Crane LLC
KM Decatur LLC
KM Eagle Gathering LLC
KM Gathering LLC
KM Kaskaskia Dock LLC
KM Liquids Terminals LLC
KM North Cahokia Land LLC
KM North Cahokia Special Project LLC
KM North Cahokia Terminal Project LLC
KM Ship Channel Services LLC
KM Treating GP LLC
KM Treating Production LLC
KM Utopia Operator LLC
KMBT Legacy Holdings LLC
KMBT LLC
KMGP Services Company, Inc.
KN Telecommunications, Inc.
Knight Power Company LLC
Lomita Rail Terminal LLC
Milwaukee Bulk Terminals LLC
MJR Operating LLC
Mojave Pipeline Company, L.L.C.
Mojave Pipeline Operating Company, L.L.C.
Paddy Ryan Crane, LLC
Palmetto Products Pipe Line LLC
PI 2 Pelican State LLC
Pinney Dock & Transport LLC
Queen City Terminals LLC
Rahway River Land LLC
River Terminals Properties GP LLC

Schedule II
(Guarantors)
Current as of: December 31, 2020

River Terminal Properties, L.P.
ScissorTail Energy, LLC
SNG Pipeline Services Company, L.L.C.
Southern Dome, LLC
Southern Gulf LNG Company, L.L.C.
Southern Liquefaction Company LLC
Southern LNG Company, L.L.C.
Southern Oklahoma Gathering LLC
SouthTex Treaters LLC
Southwest Florida Pipeline LLC
SRT Vessels LLC
Stevedore Holdings, L.P.
Tejas Gas, LLC
Tejas Natural Gas, LLC
Tennessee Gas Pipeline Company, L.L.C.
Tennessee Gas Pipeline Issuing Corporation
Texan Tug LLC
TGP Pipeline Services Company, L.L.C.
TransColorado Gas Transmission Company LLC
Transload Services, LLC
Utica Marcellus Texas Pipeline LLC
Western Plant Services LLC
Wyoming Interstate Company, L.L.C.

SCHEDULE III

Excluded Subsidiaries

ANR Real Estate Corporation
Coastal Eagle Point Oil Company
Coastal Oil New England, Inc.
Colton Processing Facility
Coscol Petroleum Corporation
El Paso CGP Company, L.L.C.
El Paso Energy Capital Trust I
El Paso Energy E.S.T. Company
El Paso Energy International Company
El Paso Marketing Company, L.L.C.
El Paso Merchant Energy North America Company, L.L.C.
El Paso Merchant Energy-Petroleum Company
El Paso Reata Energy Company, L.L.C.
El Paso Remediation Company
El Paso Services Holding Company
EPEC Corporation
EPEC Oil Company Liquidating Trust
EPEC Polymers, Inc.
EPED Holding Company
KN Capital Trust I
KN Capital Trust III
Mesquite Investors, L.L.C.

Note: The Excluded Subsidiaries listed on this Schedule III may also be Excluded Subsidiaries pursuant to other exceptions set forth in the definition of “Excluded Subsidiary”.

Kinder Morgan, Inc.
Subsidiaries of the Registrant as of December 31, 2020

Entity Name [(a)]	Place of Incorporation
Agnes B Crane, LLC	Louisiana
American Petroleum Tankers II LLC	Delaware
American Petroleum Tankers III LLC	Delaware
American Petroleum Tankers IV LLC	Delaware
American Petroleum Tankers IX LLC	Delaware
American Petroleum Tankers LLC	Delaware
American Petroleum Tankers Parent LLC	Delaware
American Petroleum Tankers V LLC	Delaware
American Petroleum Tankers VI LLC	Delaware
American Petroleum Tankers VII LLC	Delaware
American Petroleum Tankers VIII LLC	Delaware
American Petroleum Tankers X LLC	Delaware
American Petroleum Tankers XI LLC	Delaware
ANR Real Estate Corporation	Delaware
APT Florida LLC	Delaware
APT Intermediate Holdco LLC	Delaware
APT New Intermediate Holdco LLC	Delaware
APT Pennsylvania LLC	Delaware
APT Sunshine State LLC	Delaware
Banquete Hub LLC (50%)	Delaware
Battleground Oil Specialty Terminal Company LLC (55%)	Delaware
Betty Lou LLC	Delaware
Calnev Pipe Line LLC	Delaware
Camino Real Gas Gathering Company LLC	Delaware
Camino Real Gathering Company, L.L.C.	Delaware
Cantera Gas Company LLC	Delaware
CDE Pipeline LLC	Delaware
Cedar Cove Midstream LLC (70%)	Delaware
Central Florida Pipeline LLC	Delaware
Cheyenne Plains Gas Pipeline Company, L.L.C.	Delaware
CIG Gas Storage Company LLC	Delaware
CIG Pipeline Services Company, L.L.C.	Delaware
Coastal Eagle Point Oil Company	Delaware
Coastal Oil New England, Inc.	Massachusetts
Colorado Interstate Gas Company, L.L.C.	Delaware
Colorado Interstate Issuing Corporation	Delaware
Copano Double Eagle LLC	Delaware
Copano Energy Finance Corporation	Delaware
Copano Energy, L.L.C.	Delaware
Copano Energy Services/Upper Gulf Coast LLC	Texas

Entity Name [a]	Place of Incorporation
Copano Field Services GP, L.L.C.	Delaware
Copano Field Services/North Texas, L.L.C.	Delaware
Copano Field Services/South Texas LLC	Texas
Copano Field Services/Upper Gulf Coast LLC	Texas
Copano Liberty, LLC	Delaware
Copano Liquids Marketing LLC	Delaware
Copano NGL Services (Markham), L.L.C.	Delaware
Copano NGL Services LLC	Texas
Copano Pipelines Group, L.L.C.	Delaware
Copano Pipelines/North Texas, L.L.C.	Delaware
Copano Pipelines/Rocky Mountains, LLC	Delaware
Copano Pipelines/South Texas LLC	Texas
Copano Pipelines/Upper Gulf Coast LLC	Texas
Copano Processing LLC	Texas
Copano Risk Management LLC	Texas
Copano Terminals LLC	Delaware
Copano/Webb-Duval Pipeline LLC	Delaware
Coscol Petroleum Corporation	Delaware
CPNO Services LLC	Texas
Dakota Bulk Terminal LLC	Delaware
Delta Terminal Services LLC	Delaware
Eagle Ford Gathering LLC	Delaware
El Paso Amazonas Energia Ltda.	Brazil
El Paso CGP Company, L.L.C.	Delaware
El Paso Cheyenne Holdings, L.L.C.	Delaware
El Paso Citrus Holdings, Inc.	Delaware
El Paso CNG Company, L.L.C.	Delaware
El Paso Energia do Brasil Ltda.	Brazil
El Paso Energy Argentina Service Company	Delaware
El Paso Energy Capital Trust I	Delaware
El Paso Energy E.S.T. Company	Delaware
El Paso Energy International Company	Delaware
El Paso Energy Marketing de Mexico, S. de R.L. de C.V.	Mexico
El Paso Energy Service Company, L.L.C.	Delaware
El Paso LLC	Delaware
El Paso Marketing Company, L.L.C.	Delaware
El Paso Merchant Energy North America Company, L.L.C.	Delaware
El Paso Merchant Energy-Petroleum Company	Delaware
El Paso Mexico Holding B.V.	Netherlands
El Paso Midstream Group LLC	Delaware
El Paso Natural Gas Company, L.L.C.	Delaware
El Paso Noric Investments III, L.L.C.	Delaware
El Paso Reata Energy Company, L.L.C.	Delaware

Entity Name [(a)]	Place of Incorporation
El Paso Remediation Company	Delaware
El Paso Rio Negro Energia Ltda.	Brazil
El Paso Ruby Holding Company, L.L.C.	Delaware
El Paso Services Holding Company	Delaware
El Paso Tennessee Pipeline Co., L.L.C.	Delaware
Elba Express Company, L.L.C.	Delaware
Elba Liquefaction Company, L.L.C. (51%)	Delaware
Elizabeth River Terminals LLC	Delaware
Emory B Crane, LLC	Louisiana
EP Ruby LLC	Delaware
EPBGP Contracting Services LLC	Delaware
EPC Building LLC	Delaware
EPC Property Holdings, Inc.	Delaware
EPEC Corporation	Delaware
EPEC Oil Company Liquidating Trust	Delaware Law
EPEC Polymers, Inc.	Delaware
EPEC Realty, Inc.	Delaware
EPED B Company	Cayman Islands
EPED Holding Company	Delaware
EPTP Issuing Corporation	Delaware
Frank L Crane, LLC	Louisiana
General Stevedores GP, LLC	Texas
General Stevedores Holdings LLC	Delaware
Harrah Midstream LLC	Delaware
HBM Environmental LLC	Delaware
Hiland Crude, LLC	Oklahoma
Hiland Partners Holdings LLC	Delaware
HPH Oklahoma Gathering LLC	Delaware
I.M.T. Land Corp.	Louisiana
ICPT, L.L.C.	Louisiana
Independent Trading & Transportation Company I, L.L.C.	Oklahoma
International Marine Terminals Partnership	Louisiana
JV Tanker Charterer LLC	Delaware
K N Capital Trust I	Delaware
K N Capital Trust II	Delaware
K N Capital Trust III	Delaware
Kinder Morgan 2-Mile LLC	Delaware
Kinder Morgan Administrative Services Tampa LLC	Delaware
Kinder Morgan Altamont LLC	Delaware
Kinder Morgan Baltimore Transload Terminal LLC	Delaware
Kinder Morgan Battleground Oil LLC	Delaware
Kinder Morgan Border Pipeline LLC	Delaware
Kinder Morgan Bulk Terminals LLC	Louisiana

Exhibit 21.1

Entity Name [(a)]	Place of Incorporation
Kinder Morgan Carbon Dioxide Transportation Company	Delaware
Kinder Morgan CO_2 Company LLC	Texas
Kinder Morgan Commercial Services LLC	Delaware
Kinder Morgan Contracting Services LLC	Delaware
Kinder Morgan Crude & Condensate LLC	Delaware
Kinder Morgan Crude Marketing LLC	Delaware
Kinder Morgan Crude Oil Pipelines LLC	Delaware
Kinder Morgan Crude to Rail LLC	Delaware
Kinder Morgan Cushing LLC	Delaware
Kinder Morgan Dallas Fort Worth Rail Terminal LLC	Delaware
Kinder Morgan Deeprock North Holdco LLC	Delaware
Kinder Morgan Endeavor LLC	Delaware
Kinder Morgan Energy Partners, L.P.	Delaware
Kinder Morgan EP Midstream LLC	Delaware
Kinder Morgan Finance Company LLC	Delaware
Kinder Morgan Foundation	Colorado
Kinder Morgan Freedom Pipeline LLC	Delaware
Kinder Morgan Galena Park West LLC	Delaware
Kinder Morgan Gas Natural de Mexico, S. de R.L. de C.V.	Mexico
Kinder Morgan GP LLC	Delaware
Kinder Morgan IMT Holdco LLC	Delaware
Kinder Morgan Keystone Gas Storage LLC	Delaware
Kinder Morgan KMAP LLC	Delaware
Kinder Morgan Las Vegas LLC	Delaware
Kinder Morgan Linden Transload Terminal LLC	Delaware
Kinder Morgan Liquids Terminals LLC	Delaware
Kinder Morgan Liquids Terminals St. Gabriel LLC	Delaware
Kinder Morgan Louisiana Pipeline Holding LLC	Delaware
Kinder Morgan Louisiana Pipeline LLC	Delaware
Kinder Morgan Marine Services LLC	Delaware
Kinder Morgan Materials Services, LLC	Delaware
Kinder Morgan Mexico LLC	Delaware
Kinder Morgan Mid Atlantic Marine Services LLC	Delaware
Kinder Morgan NatGas O&M LLC	Delaware
Kinder Morgan NGPL Holdings LLC	Delaware
Kinder Morgan North Texas Pipeline LLC	Delaware
Kinder Morgan Operating LLC "A"	Delaware
Kinder Morgan Operating LLC "B"	Delaware
Kinder Morgan Operating LLC "C"	Delaware
Kinder Morgan Operating LLC "D"	Delaware
Kinder Morgan Pecos LLC	Delaware
Kinder Morgan Pecos Valley LLC	Delaware
Kinder Morgan Petcoke GP LLC	Delaware

Exhibit 21.1

Entity Name [(a)]	**Place of Incorporation**
Kinder Morgan Petcoke LP LLC	Delaware
Kinder Morgan Petcoke, L.P.	Delaware
Kinder Morgan Petroleum Tankers LLC	Delaware
Kinder Morgan Pipeline LLC	Delaware
Kinder Morgan Pipeline Servicios de Mexico S. de R.L. de C.V.	Mexico
Kinder Morgan Port Manatee Terminal LLC	Delaware
Kinder Morgan Port Sutton Terminal LLC	Delaware
Kinder Morgan Port Terminals USA LLC	Delaware
Kinder Morgan Portland Jet Line LLC	Delaware
Kinder Morgan Production Company LLC	Delaware
Kinder Morgan Products Terminals LLC	Delaware
Kinder Morgan Rail Services LLC	Delaware
Kinder Morgan Resources II LLC	Delaware
Kinder Morgan Resources III LLC	Delaware
Kinder Morgan Resources LLC	Delaware
Kinder Morgan Scurry Connector LLC	Delaware
Kinder Morgan Services International LLC	Delaware
Kinder Morgan Seven Oaks LLC	Delaware
Kinder Morgan SNG Operator LLC	Delaware
Kinder Morgan Southeast Terminals LLC	Delaware
Kinder Morgan Tank Storage Terminals LLC	Delaware
Kinder Morgan Tejas Pipeline GP LLC	Delaware
Kinder Morgan Tejas Pipeline LLC	Delaware
Kinder Morgan Terminals Wilmington LLC	Delaware
Kinder Morgan Terminals, Inc.	Delaware
Kinder Morgan Texas Pipeline LLC	Delaware
Kinder Morgan Texas Terminals, L.P.	Delaware
Kinder Morgan Transmix Company, LLC	Delaware
Kinder Morgan Treating LP	Delaware
Kinder Morgan Urban Renewal II, LLC	New Jersey
Kinder Morgan Urban Renewal, L.L.C.	New Jersey
Kinder Morgan Utica LLC	Delaware
Kinder Morgan Vehicle Services LLC	Delaware
Kinder Morgan Virginia Liquids Terminals LLC	Delaware
Kinder Morgan Wink Pipeline LLC	Delaware
KinderHawk Field Services LLC	Delaware
KM Canada Terminals ULC	Alberta (Canada)
KM Crane LLC	Maryland
KM Decatur LLC	Delaware
KM Eagle Gathering LLC	Delaware
KM Express LLC	Delaware
KM Gathering LLC	Delaware
KM Insurance Texas Inc.	Texas

Exhibit 21.1

Entity Name [(a)]	Place of Incorporation
KM Kaskaskia Dock LLC	Delaware
KM Liquids Terminals LLC	Delaware
KM North Cahokia Land LLC	Delaware
KM North Cahokia Special Project LLC	Delaware
KM North Cahokia Terminal Project LLC	Delaware
KM Phoenix Holdings LLC (75%)	Delaware
KM Ship Channel Services LLC	Delaware
KM Treating GP LLC	Delaware
KM Treating Production LLC	Delaware
KM Utopia Operator Limited	Alberta (Canada)
KM Utopia Operator LLC	Delaware
KMBT Legacy Holdings LLC	Tennessee
KMBT LLC	Delaware
KMGP Services Company, Inc.	Delaware
KN Telecommunications, Inc.	Colorado
Knight Power Company LLC	Delaware
Lomita Rail Terminal LLC	Delaware
Mesquite Investors, L.L.C.	Delaware
Milwaukee Bulk Terminals LLC	Wisconsin
MJR Operating LLC	Maryland
Mojave Pipeline Company, L.L.C.	Delaware
Mojave Pipeline Operating Company, L.L.C.	Texas
Paddy Ryan Crane, LLC	Louisiana
Palmetto Products Pipe Line LLC	Delaware
PI 2 Pelican State LLC	Delaware
Pinney Dock & Transport LLC	Delaware
Queen City Terminals LLC	Delaware
Rahway River Land LLC	Delaware
River Terminals Properties GP LLC	Delaware
River Terminals Properties, L.P.	Tennessee
ScissorTail Energy, LLC	Delaware
SFPP, L.P. (99.5%)	Delaware
SNG Pipeline Services Company, L.L.C.	Delaware
Southern Dome, LLC	Delaware
Southern Gulf LNG Company, L.L.C.	Delaware
Southern Liquefaction Company LLC	Delaware
Southern LNG Company, L.L.C.	Delaware
Southern Oklahoma Gathering LLC	Delaware
SouthTex Treaters LLC	Delaware
Southwest Florida Pipeline LLC	Delaware
SRT Vessels LLC	Delaware
Stevedore Holdings, L.P.	Delaware
Tejas Gas, LLC	Delaware

Exhibit 21.1

Entity Name [a]	**Place of Incorporation**
Tejas Natural Gas, LLC	Delaware
Tennessee Gas Pipeline Company, L.L.C.	Delaware
Tennessee Gas Pipeline Issuing Corporation	Delaware
Texan Tug LLC	Delaware
TGP Pipeline Services Company, L.L.C.	Delaware
The Pecos Carbon Dioxide Pipeline Company (95.28%)	Texas
TransColorado Gas Transmission Company LLC	Delaware
Transload Services, LLC	Illinois
Utica Marcellus Texas Pipeline LLC	Delaware
Webb/Duval Gatherers (91%)	Texas
Western Plant Services LLC	Delaware
Wyoming Interstate Company, L.L.C.	Delaware

[a] Where included, percentages in parentheses represent Kinder Morgan, Inc.’s ownership of less-than-wholly owned subsidiaries.

List of Guarantor Subsidiaries

The Cross Guarantee Agreement furnished as Exhibit 10.14 to this Annual Report on Form 10-K sets forth, as of December 31, 2020, the registrant’s guarantor subsidiaries on Schedule II thereto and the guaranteed securities on Schedule I thereto.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We hereby consent to the incorporation by reference in the Registration Statements on (i) Form S-3 (No. 333-240108) and Form S-8 (Nos. 333-172170, 333-172582, 333-172584, 333-172606, 333-181782 and 333-205430) of Kinder Morgan, Inc. of our report dated February 5, 2021 relating to the financial statements and the effectiveness of internal control over financial reporting, which appears in this Form 10-K.

/s/PricewaterhouseCoopers LLP

Houston, Texas
February 5, 2021

Exhibit 31.1

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Steven J. Kean, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan, Inc.;

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 in the United States;

    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 (or persons performing the equivalent functions):

    a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 5, 2021

/s/ Steven J. Kean
Steven J. Kean
Chief Executive Officer

Exhibit 31.2

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO RULE 13A-14(A) OR 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934,
AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, David P. Michels, certify that:

1. I have reviewed this annual report on Form 10-K of Kinder Morgan, Inc.;

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 in the United States;

    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 (or persons performing the equivalent functions):

    a. all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 5, 2021

/s/ David P. Michels
David P. Michels
Vice President and Chief Financial Officer

Exhibit 32.1

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan, Inc. (the "Company") for the yearly period ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(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 Company.

Date: February 5, 2021

/s/ Steven J. Kean
Steven J. Kean
Chief Executive Officer

Exhibit 32.2

KINDER MORGAN, INC. AND SUBSIDIARIES
CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906
OF THE
SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report on Form 10-K of Kinder Morgan, Inc. (the "Company") for the yearly period ended December 31, 2020, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), the undersigned, in the capacity and on the date indicated below, hereby certifies pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(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 Company.

Date: February 5, 2021

/s/ David P. Michels
David P. Michels
Vice President and Chief Financial Officer