INVESTOR PRESENTATION

November 2021

KINDER MORGAN

Disclosure

Forward-looking statements / non-GAAP financial measures / industry & market data

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Forward-Looking Statements – This presentation includes forward-looking statements within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act"). Forward-looking statements include any statement that does not relate strictly to historical or current facts and include statements accompanied by or using words such as "anticipate," "believe," "intend," "plan," "projection," "forecast," "strategy," "outlook," "continue," "estimate," "expect," "may," "will," "shall," and "long- term". In particular, statements, express or implied, concerning future actions, conditions or events, including long-term demand for our assets and services, energy transition-related opportunities, including opportunities related to alternative energy sources, future operating results, expected leverage or the ability to generate revenues, income or cash flow or to pay dividends; the prospects for RNG; and the anticipated timing and benefits to KMI's business and stockholders of Kinetrex's planned development projects, are forward-looking statements. Forward-looking statements are not guarantees of performance. They involve risks, uncertainties and assumptions. There is no assurance that any of the actions, events or results of the forward-looking statements will occur, or if any of them do, what impact they will have on our results of operations or financial condition. Because of these uncertainties, you are cautioned not to put undue reliance on any forward- looking statement. 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.

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GAAP – Unless otherwise stated, all historical and estimated future financial and other information included in this presentation have been prepared in accordance with generally accepted accounting principles in the United States ("GAAP").

Non-GAAP – In addition to using financial measures prescribed by GAAP, we use non-generally accepted accounting principles ("non-GAAP") financial measures in this presentation. Descriptions of our non-GAAP financial measures, as well as reconciliations of historical non-GAAP financial measures to their most directly comparable GAAP measures, can be found in this presentation under "Non-GAAP Financial Measures and Reconciliations". These non-GAAP financial measures do not have any standardized meaning under GAAP and may not be comparable to similarly titled measures presented by other issuers. As such, they should not be considered as alternatives to GAAP financial measures.

Industry and Market Data - Certain data included in this presentation has been derived from a variety of sources, including independent industry publications, government publications and other published independent sources. Although we believe that such third-party sources are reliable, we have not independently verified, and take no responsibility for, the accuracy or completeness of such data.

Leader in North American Energy Infrastructure

Unparalleled & irreplaceable asset footprint built over decades

Largest natural gas transmission network

- ~70,000 miles of natural gas pipelines
- ~700 bcf of working storage capacity
- ~1,200 miles of natural gas liquids pipelines

Largest independent transporter of refined products

- Transport ~1.7 mmbbld of refined products
- ~6,800 miles of refined products pipelines
- ~3,100 miles of crude pipelines

Largest independent terminal operator

- 144 terminals & 16 Jones Act vessels

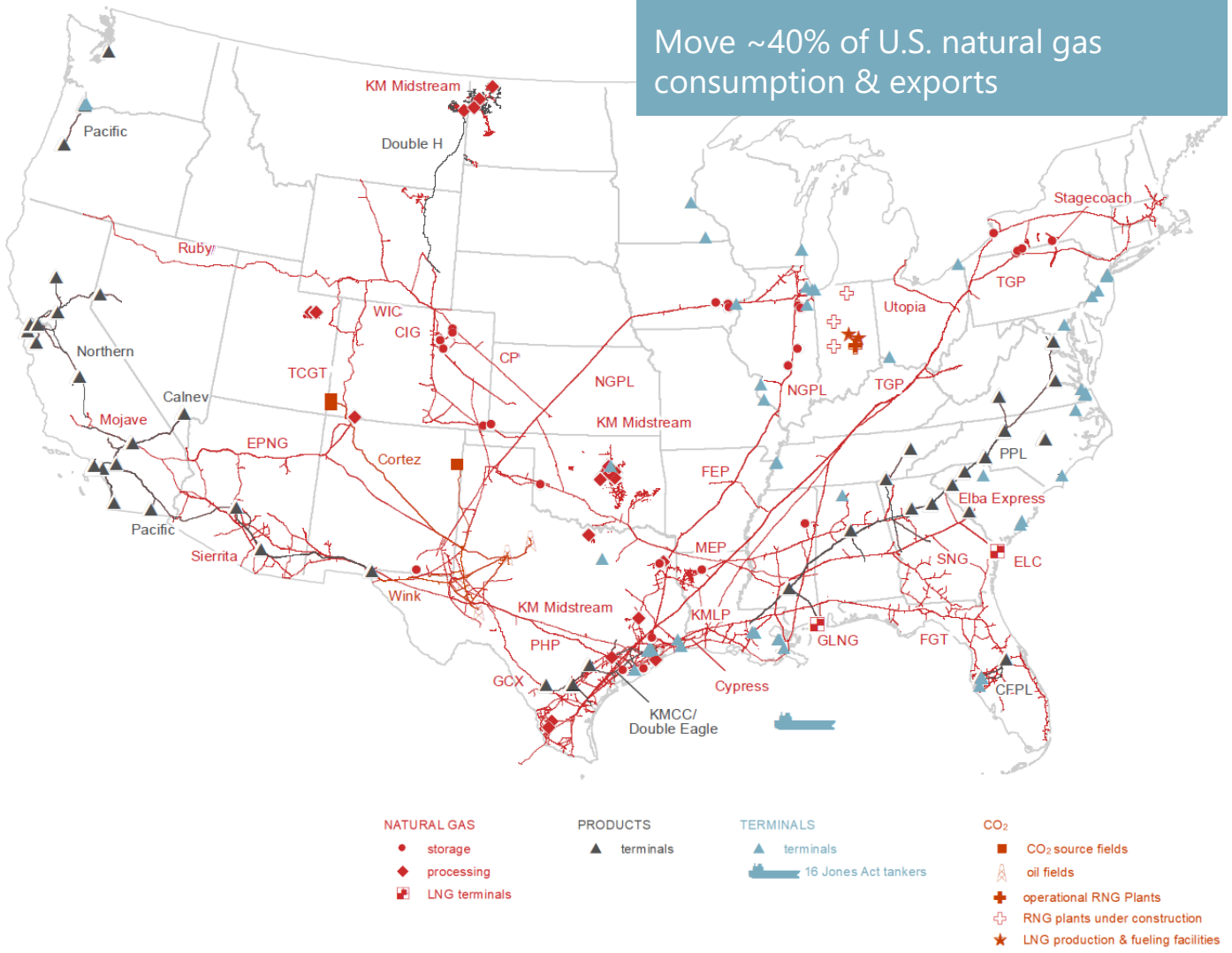
Largest CO_2 transport capacity of ~1.5 bcfd

- ~1,500 miles of CO_2 pipelines

BUSINESS MIX

Connecting major U.S. natural gas resource plays to key demand centers

Move ~40% of U.S. natural gas consumption & exports



Note: Mileage & volumes are company-wide per 2021 budget. Business mix based on 2021 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Core Holding in Any Portfolio

Generating significant cash flow & returning significant value to shareholders

>$35 billion market capitalization	One of the 10 largest energy companies in the S&P500
~13% owned by management	Highly-aligned management with significant equity interests
$7.9 billion 2021 forecast EBITDA	Benefitted by Uri and partial contributions from acquisitions
~6% current dividend yield	Top 10 dividend yield in S&P500 Declared 3% YoY dividend increase for 3Q 2021
$2 billion share buyback program	Over $1.4 billion of program capacity remaining

Strategy

Maximize the value of our assets on behalf of shareholders

Stable, fee-based assets

Core energy infrastructure

Safe & efficient operator

Multi-year contracts

>90% take-or-pay & fee-based cash flows

Invest in a low carbon future

Newly formed Energy Transition Ventures Group

$1.6 billion backlog with 70% allocated to low carbon investments

Investing in natural gas, RNG, and liquid biofuels infrastructure

Financial flexibility

4.0x 2021 expected Net Debt / Adjusted EBITDA[(a)]

Long-term target remains around 4.5x

Low cost of capital

Mid-BBB credit ratings

Ample liquidity

Reduced net debt by >$12 billion since 3Q 2015

Disciplined capital allocation

Conservative assumptions

High return thresholds

Self-funding 100% of capex & dividends for last five years

Enhance shareholder value

Maintain strong balance sheet

Attractive projects

Dividend growth

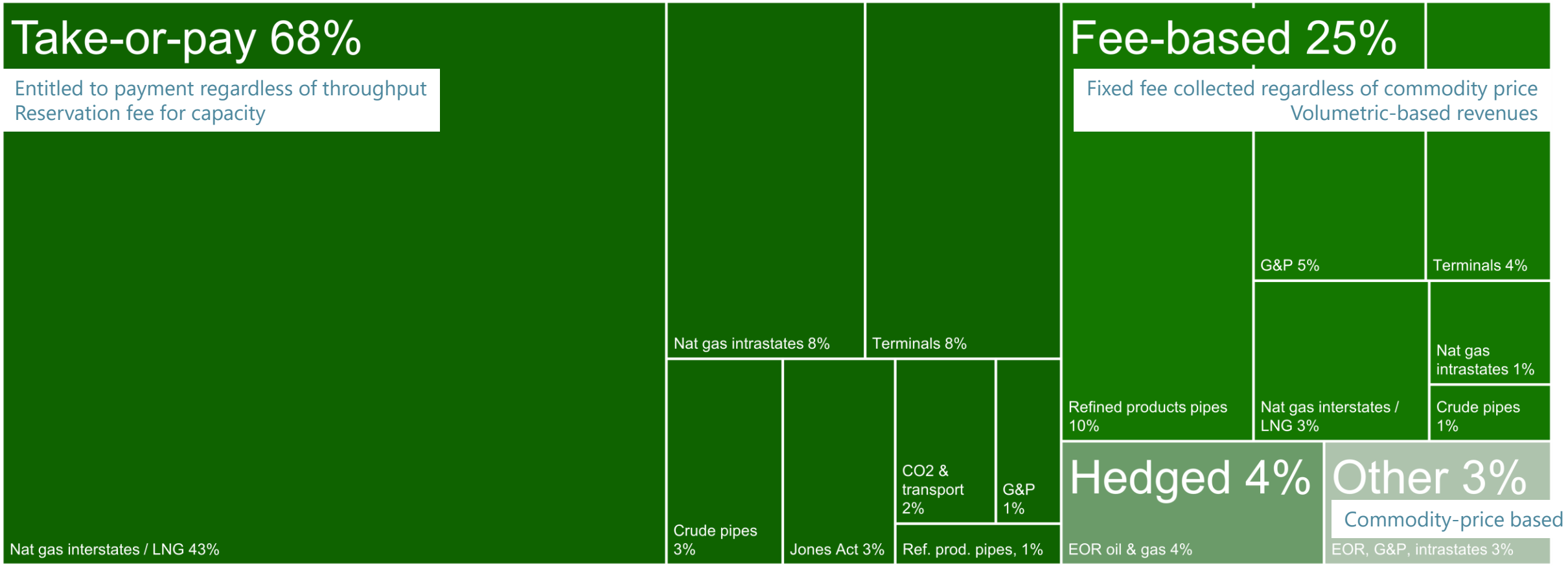
Share repurchases

a) See Non-GAAP Financial Measures & Reconciliations.

Highly-Contracted Cash Flows

Stable cash flows with ~72% take-or-pay or hedged earnings

CONTRACT MIX OF 2021B ADJUSTED SEGMENT EBDA



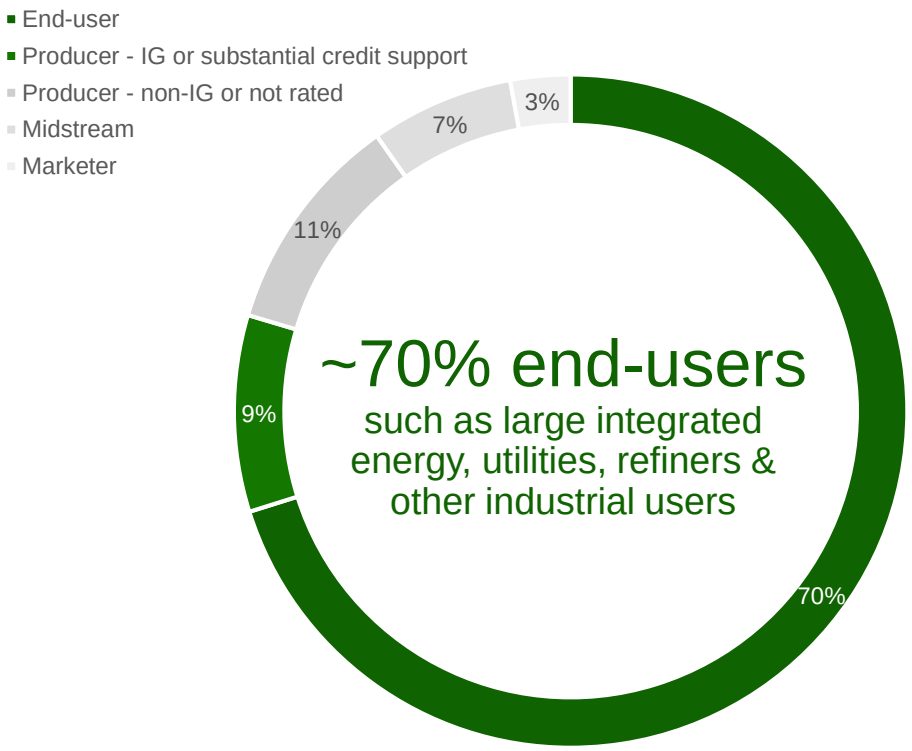
Disciplined approach to managing price volatility
Substantially hedged near-term price exposure

Note: See Non-GAAP Financial Measures & Reconciliations. Intrastates includes term sale portfolio.

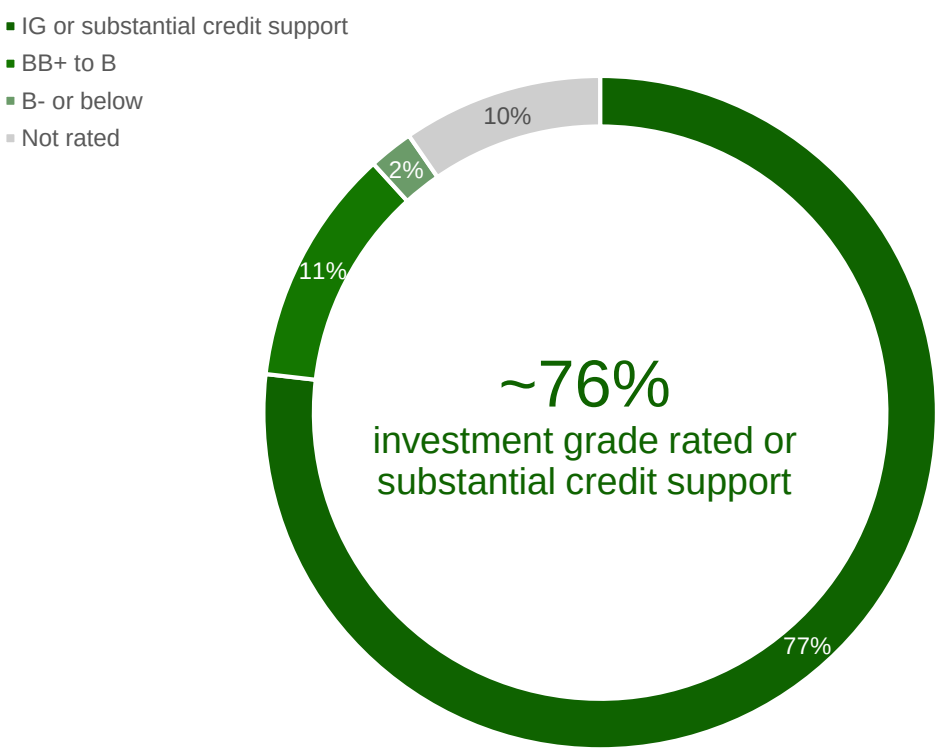
Customers Are Primarily End-Users of the Products We Handle

Net revenues underpinned by investment grade counterparties & credit support | Ratings as of October 11, 2021

CUSTOMER TYPE



CREDIT RATING



Only ~2% of exposure from B- or below rated customers, including non-rated customers in bankruptcy, after collateral & remarketing efforts

Note: Based on 2021 budgeted net revenues, which include our share of unconsolidated joint ventures & net margin for our Texas Intrastate customers & other midstream businesses. Pie charts includes 229 customers >$5mm at their respective company credit ratings per S&P, Moody's & Fitch, shown at the S&P-equivalent rating & utilizing a blended rate for split-rated companies, which represent ~85% of total net revenues.

Our Business is Resilient throughout an Energy Transition

what we do today…

is valuable & will be needed for a long time

"energy transitions take decades"
- Vaclav Smil, Distinguished Professor Emeritus in the Faculty of Environment, Univ. of Manitoba

"whichever way things evolve, fuels of various kinds will be essential to the future of energy"
- International Energy Agency

helps meet environmental goals

infrastructure supporting the displacement of higher emissions energy sources (e.g. coal)

management emphasis on reducing emissions & meeting ESG objectives in our existing business

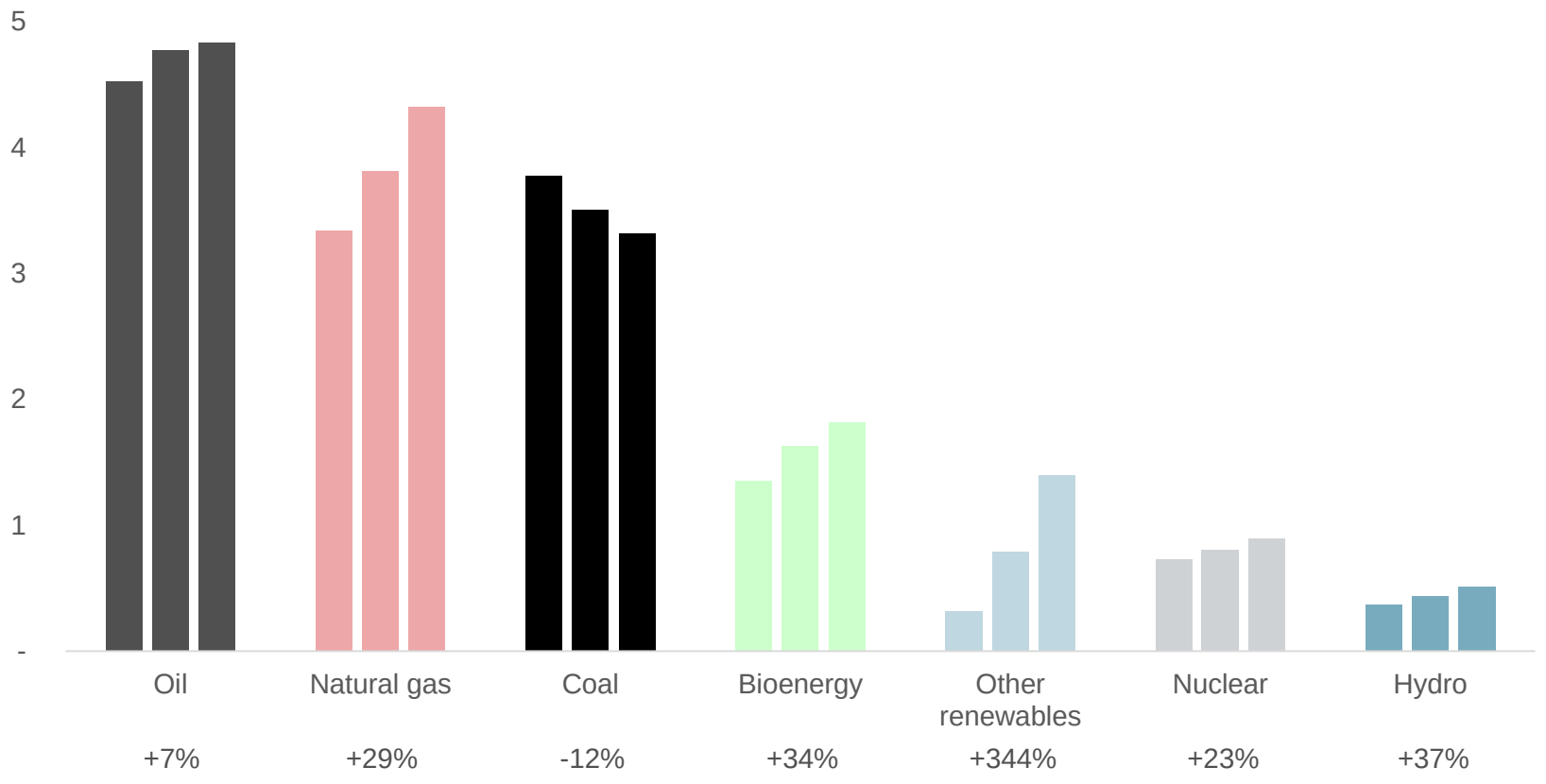
…positions us for the energy business of the future

All Available Sources Required to Meet Demand Outlook

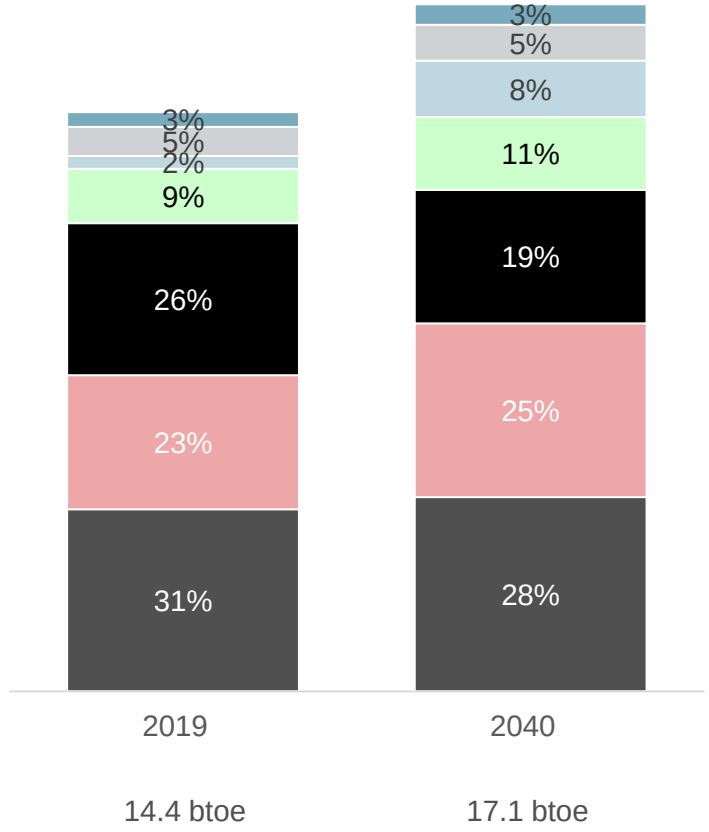
Total energy demand expected to grow nearly 20%

GLOBAL PRIMARY ENERGY DEMAND BY FUEL

billions tons oil equivalent (btoe) | 2019, 2030, 2040



total demand & % mix



Source: International Energy Agency, World Energy Outlook, October 2020 (Total Primary Demand in Stated Policies Scenario).

Note: Other renewables include geothermal, solar photovoltaics (PV), concentrating solar power (CSP), wind & marine (tide & wave) energy for electricity & heat generation.

Substantial Growth Projected for U.S. Natural Gas

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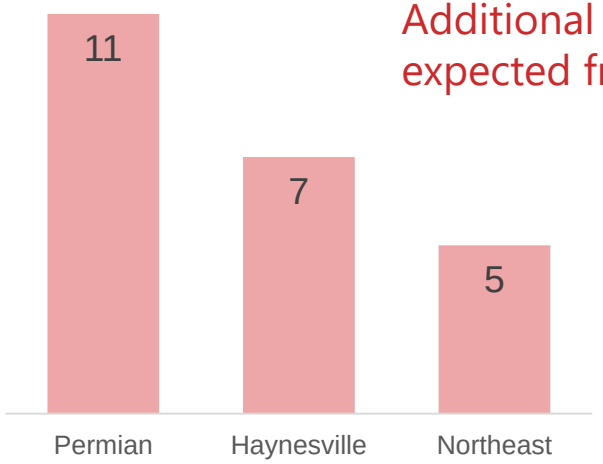
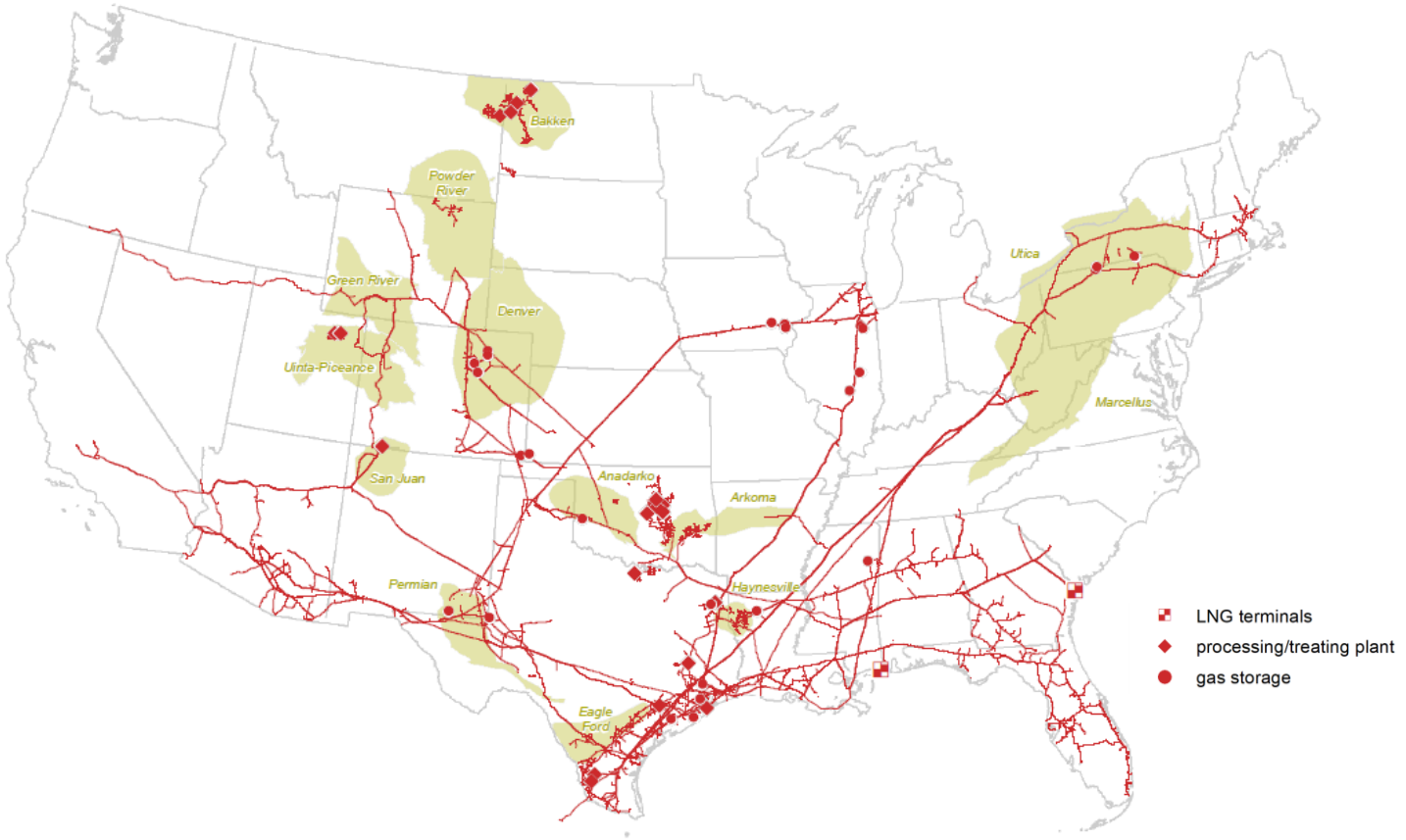
KEY BASINS DRIVING U.S. GROWTH

2020 to 2030 growth in bcfd



Additional 23 bcfd expected from three areas



DEMAND in bcfd

Exports & industrial driving majority of growth

>80% of forecast demand growth is driven by **TX & LA**

Our network connects key supply basins to multiple demand points along the Gulf Coast

Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, June 2021. Growth relative to projected 2020 production at the time of the report. Total U.S. natural gas production to grow by 17 bcfd by 2030; forecast assumes aggregate of other U.S. basins shrinks by 6 bcfd. Industrial sector includes WoodMackenzie's "Other" category, comprised of lease and plant fuel and fuel used for liquefaction at export facilities.

Supporting the Buildout of U.S. LNG Exports

Serving significant liquefaction capacity & well-positioned to capture more

Kinder Morgan network advantages

Natural gas transportation leader

~70,000 miles of natural gas pipelines
Move ~40% of U.S. natural gas consumption & exports

Supply diversity

Connected to major U.S. natural gas resource plays

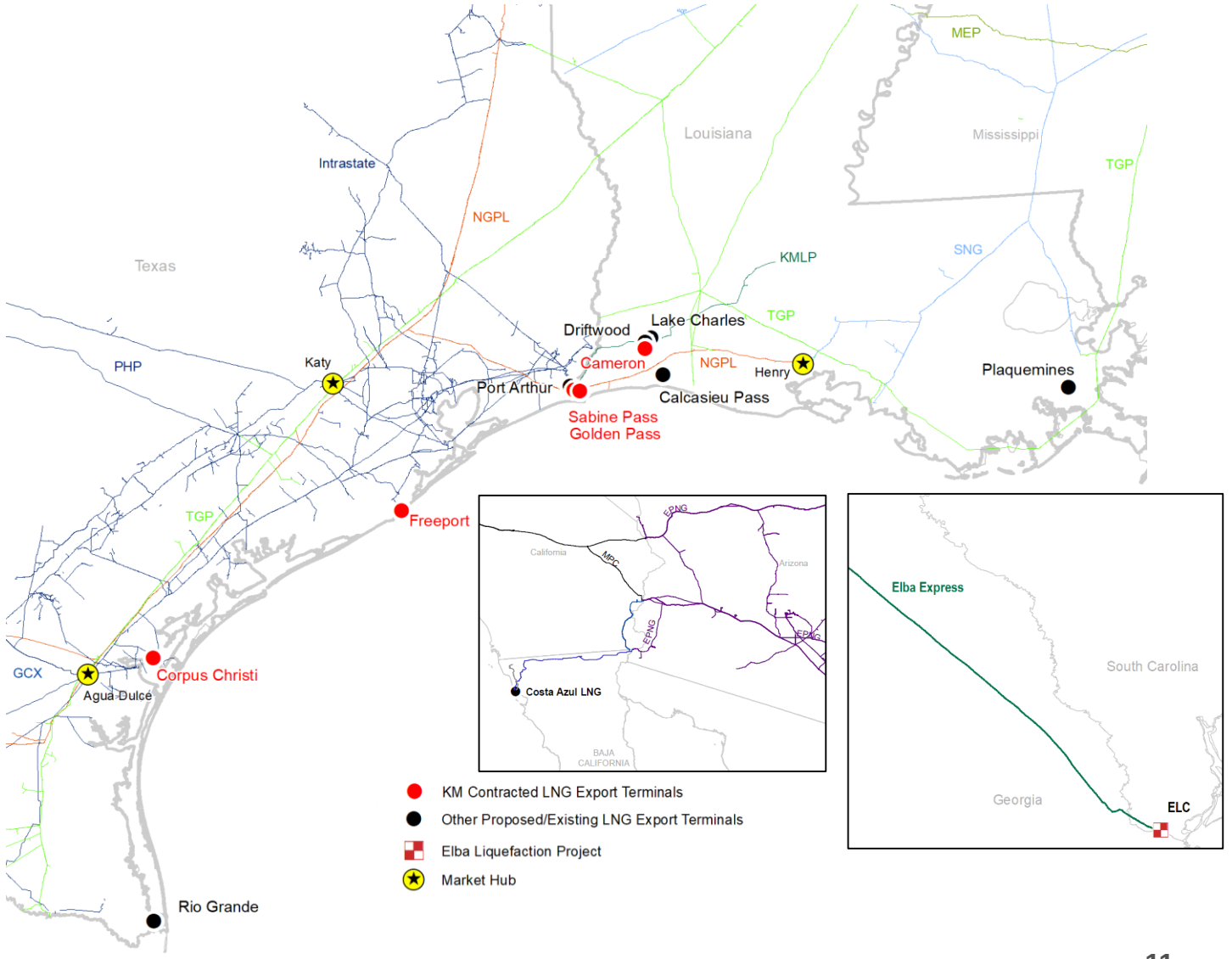
Premier deliverability

700 bcf of working gas storage in production & market areas

Transporter of choice

Contracted capacity online	Contracted capacity to come	Average remaining contract term	In active discussions
~ 4.7 bcfd	1.4 bcfd	16 years	2-5 bcfd

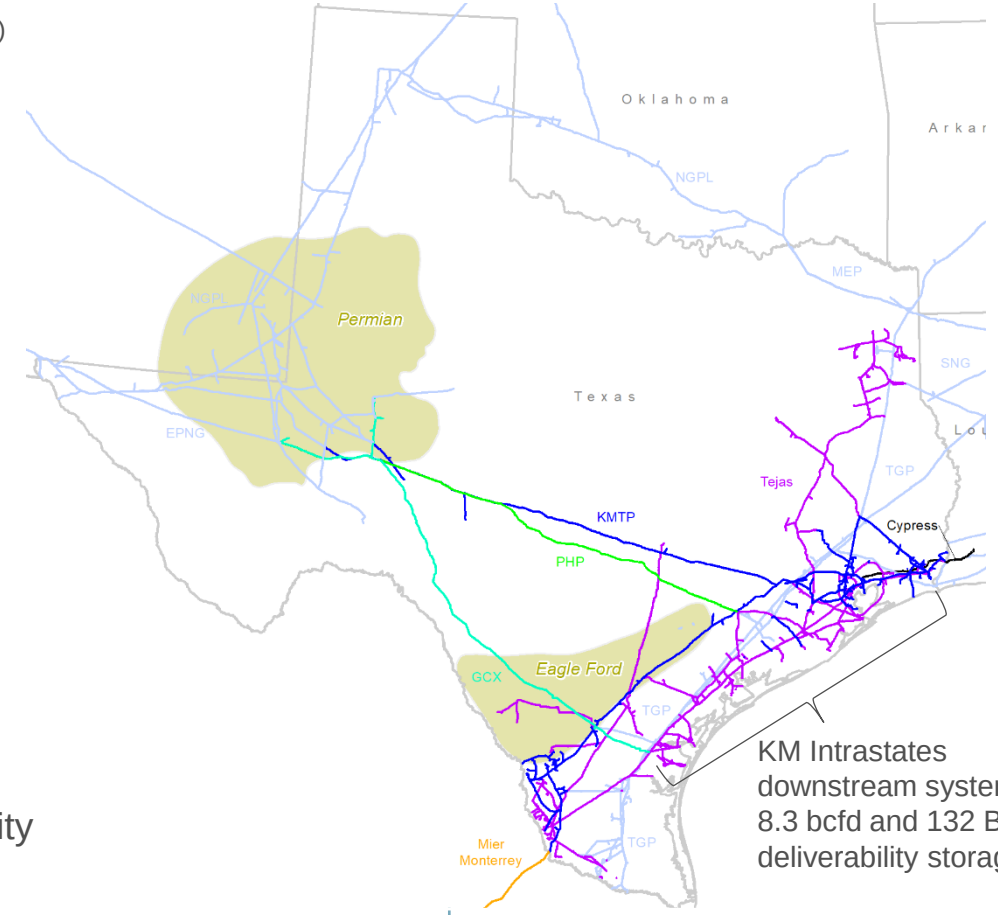
Also deliver ~1 bcfd of producer / marketer supply



Valuable Texas Natural Gas Systems

Winter Storm Uri emphasized the importance of our Texas Natural Gas network

- Texas Intrastates system represents ~10% of total Adjusted Segment EBDA[(a)]
  - Highly contracted with >80% take-or-pay[(a)]
  - Average transportation contract tenor >5 years
- 7,000 mile pipeline network in Texas
  - GCX & PHP connect 4+ bcfd of Permian supply to the Gulf Coast
  - 8.3 bcfd capacity on KMTP / Tejas
  - Footprint along Gulf Coast offers broad end-market optionality (power, petrochemical, industrial, LDC)
  - Serves exports (LNG facilities and Mexico)
- 132 Bcf of high deliverability market area storage
  - Primarily contracted to third-parties, including LDCs and power generators
  - KMI retains a portion of this storage to balance our intrastate pipeline gas system and support seasonal and intraday customer needs; transact at market prices
- Purchase and sales opportunities
  - Match purchases and sales to essentially secure a transportation margin
  - Sales volumes have historically ranged 2.1-2.7 bbtud (2015 – 3Q 2021)
- Contract structure designed to optimize operations for stability and deliverability



KM Intrastates downstream system: 8.3 bcfd and 132 Bcf high deliverability storage

Highly responsive storage is increasingly important:

Critical to supporting human needs during Uri

Helps backstop growing renewable power generation

Supports LNG export facilities

a) Note: Based on Adjusted Segment EBDA per the 2021 budget. See Non-GAAP Financial Measures & Reconciliations.

$1,225 million Acquisition of Northeast Transport & Storage Assets

Enhancing our service to Northeast customers with complementary assets connected to TGP

KMI acquired Stagecoach Gas Services

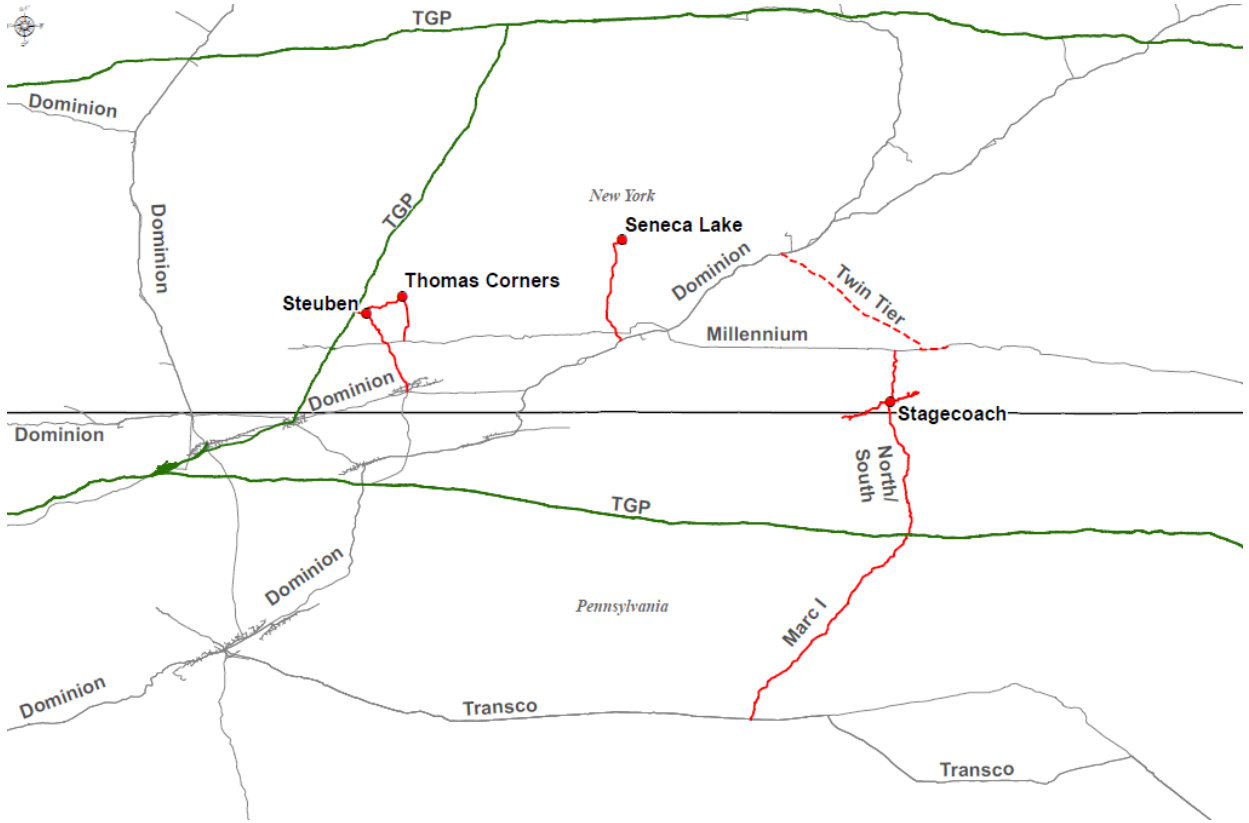
- ~10x 2020 EBITDA before synergies
- Immediately accretive, primarily paid with cash on hand
- Transaction closed in 3Q 2021[a]
- Twin Tier pipeline expected to close in 4Q 2021

FERC-regulated natural gas transport & storage in NY & PA

- ~41 bcf of FERC-certificated capacity across 4 storage facilities
- ~3 bcfd of aggregate capacity across 185 miles of transportation pipelines
- Multiple interconnects to major interstate natural gas pipelines including TGP, Transco, Millennium, Dominion

Stable, fee-based infrastructure

- FERC-regulated assets
- Highly contracted with ~80% take-or-pay[b]
- Average contract tenor ~3 years
- Anchored by major Northeast utilities and Marcellus producers
- Market based rates for storage facilities



Responsive storage is increasingly important:

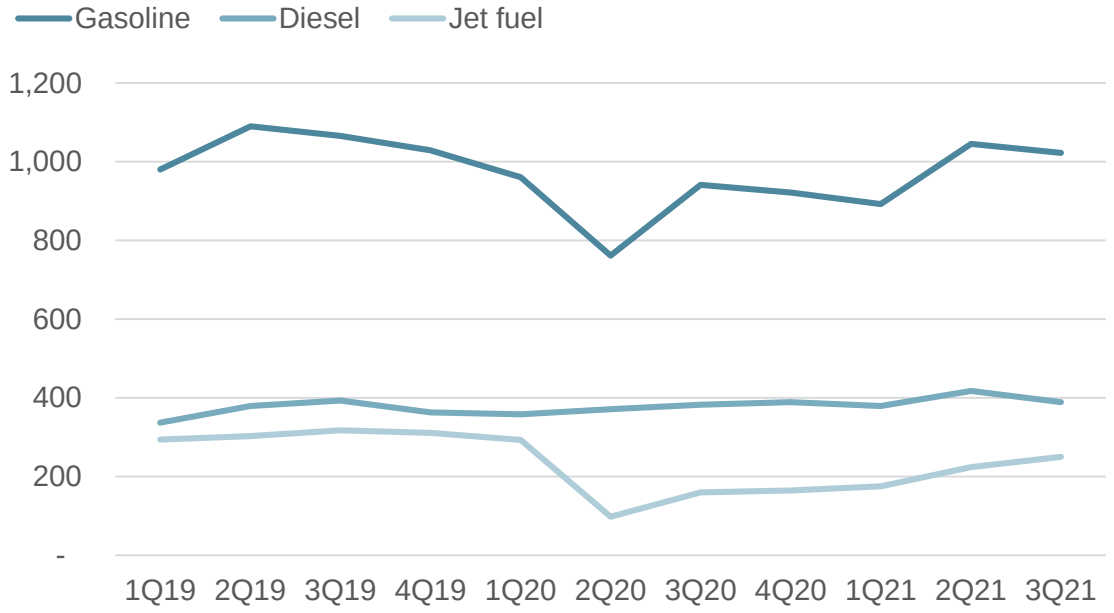
Helps backstop growing renewable power generation

Helps meet critical needs in extreme weather

a) Vast majority of assets closed in 3Q 2021, with remaining Twin Tier pipeline ($30 million) expected to close in 4Q 2021
b) Based on FY 2021 forecast.

Volume Recovery Still Playing Out

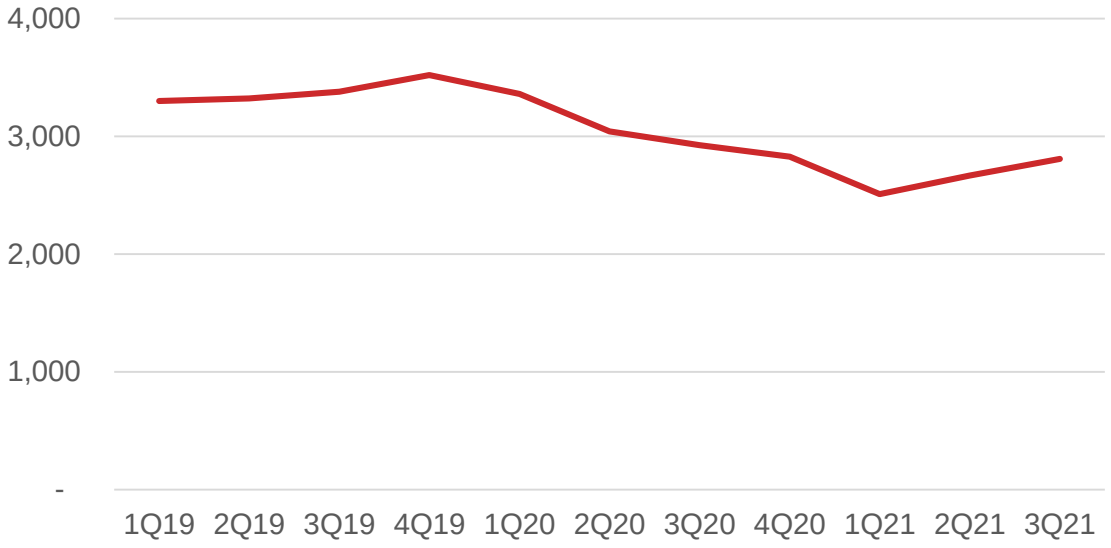
REFINED PRODUCTS VOLUMES mbbld



- Total volumes -1% in 3Q 2021 vs 2Q
  - Delta variant had negative effect on volumes which we expect to diminish in 4Q
  - Road fuel -3% (includes some Hurricane Ida impacts)
  - Jet fuel volumes +12%
- 3Q 2021 vs 3Q 2019 (pre pandemic)
  - Road fuels -3% and jet fuel -21%

1,599 mbbld YTD | budgeted 1,676 mbbld for 2021

NATURAL GAS G&P VOLUMES mmcfd



- 3Q 2021 volumes +5% vs 2Q, including:
  - +12% Eagle Ford
  - +8% Haynesville
  - Bakken has been a little slower than anticipated in bringing on new wells but our producer customers have indicated that they will continue bringing on new production, with some wells being pushed into next year

2,662 mmcfd YTD | budgeted 2,864 mmcfd for 2021

West Coast Renewable Fuels Projects

Subsidies & state goals for emissions reductions are driving increased RD volumes

- Particularly in California where stacked subsidies currently average >$4.00/gal (RIN+LCFS+BTC)

Added Bradshaw RD rail hub project to backlog

- Expect 1Q23 in-service
- Accommodates 15 mbbld of blended diesel at the truck rack

Potential to also construct a new RD terminal in Southern CA

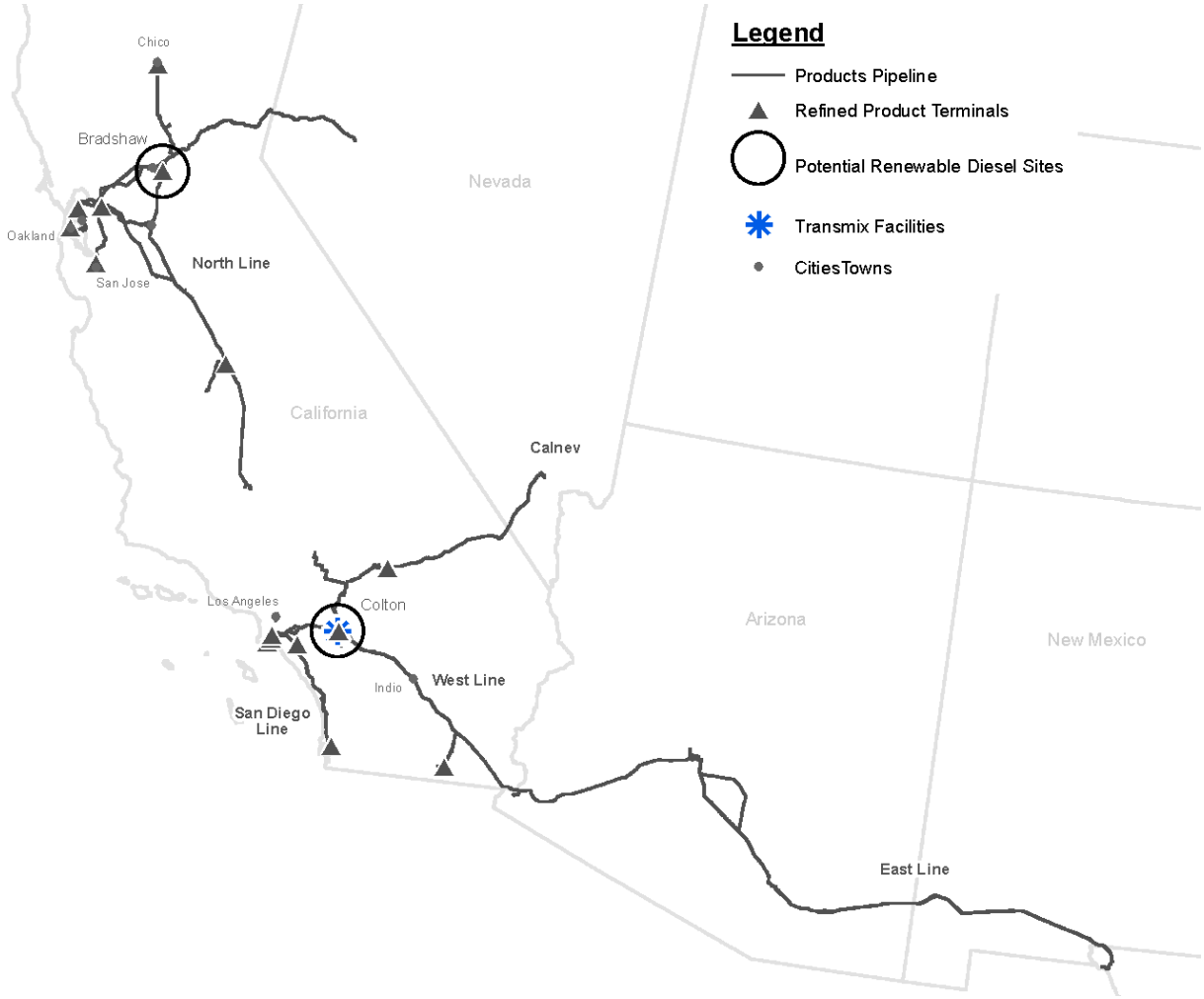
- Connect marine RD supplies in the LA harbor hub to nearby growth areas via SFPP
- Would be the first movement of pure RD by pipeline in the U.S.

Scope of RD hub projects

- Allows customers to deliver RD for blending with regular diesel & biodiesel for multiple concentrations of renewable fuel at our truck racks
- Segregated storage for renewable products (RD and biodiesel)
- Further expansion opportunities possible
- Biodiesel blend capabilities will increase from existing 5% limit to 20%

Carson truck rack project in the backlog

- Expect 2Q22 in-service
- Connects marine RD supplies in the LA harbor hub to Carson Terminal truck rack for delivery of unblended RD to the local markets

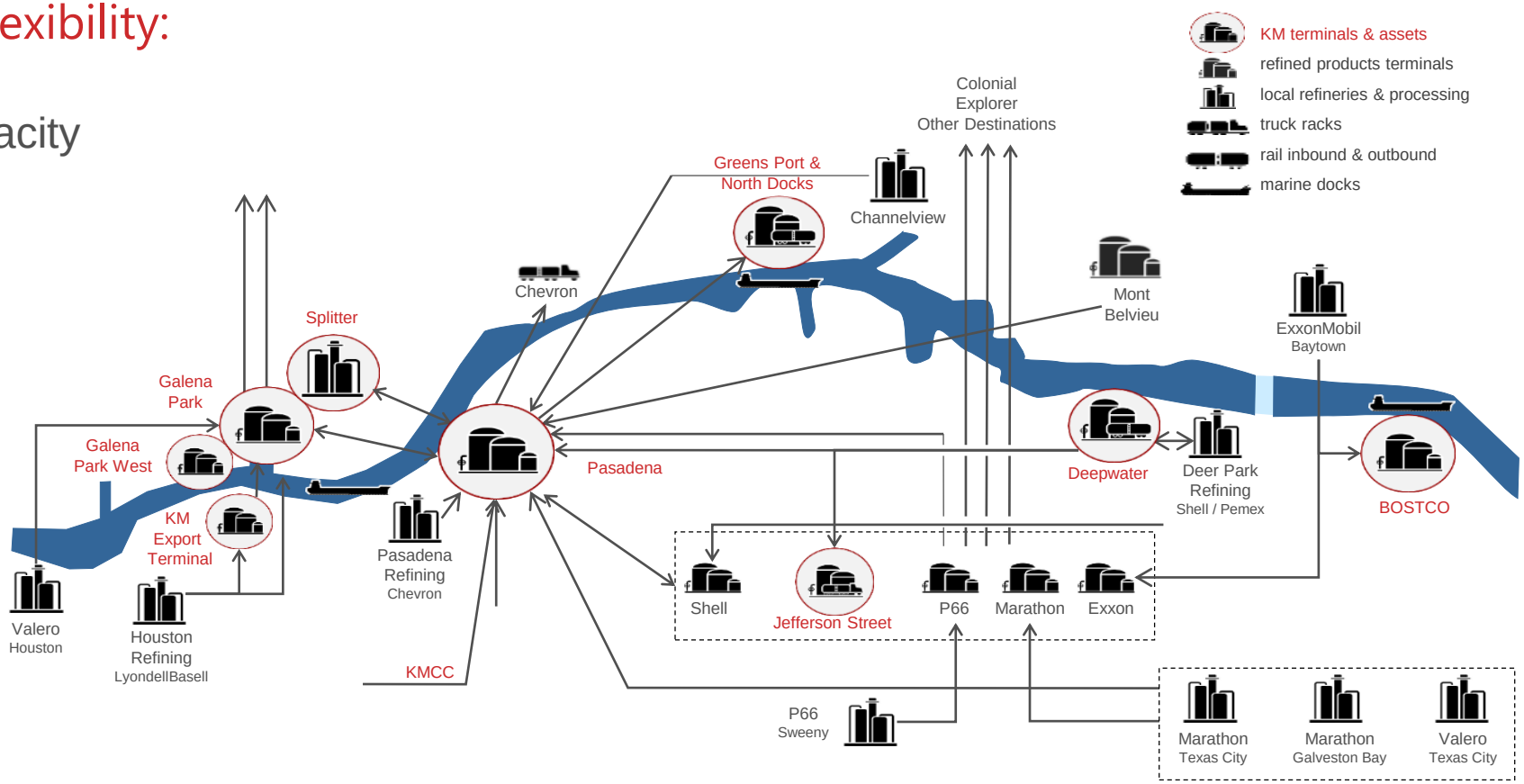


Our Integrated Terminal Network on Houston Ship Channel

Refined products focused with an irreplaceable collection of assets, capabilities & market-making connectivity

Our unmatched scale & flexibility:

- **43** million barrels total capacity
- **29** inbound pipelines
- **18** outbound pipelines
- **16** cross-channel pipelines
- **11** ship docks
- **39** barge spots
- **35** truck bays
- **3** unit train facilities



Over $2.1 billion invested since 2010

Note: Asset metrics include projects currently under construction.

Partnered with NESTE on Renewable Fuels Logistics

Leading position in fast growing market

Modifying 30 tanks & enhancing rail, truck, and marine capabilities at Harvey for renewable feedstock movements

$65 million capex

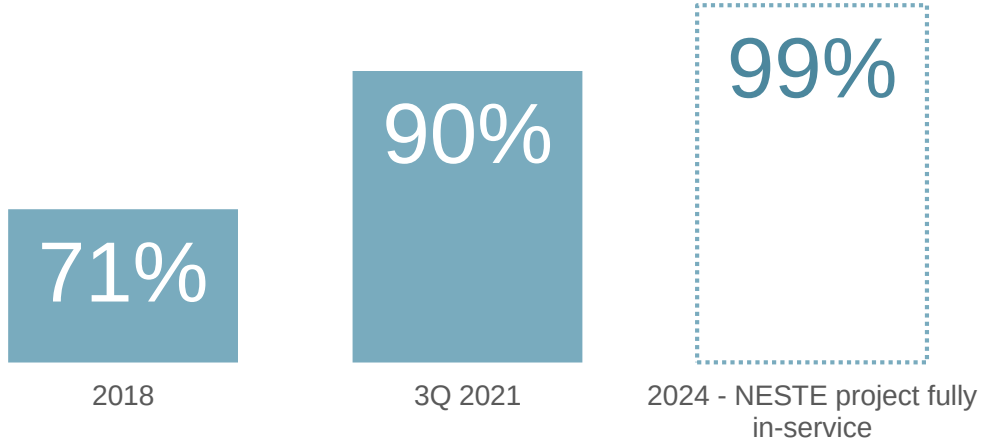
1Q 2023
operational

657 mbbl capacity
can expand further

Preferred partner for NESTE

- Our flexible terminaling network improves efficiency & sustainability of NESTE supply chain
- Network scale can keep pace with NESTE's RD feedstock growth
- Handle other renewable volumes for NESTE including
  - Feedstock in Midwest & Northeast
  - SAF at Galena Park
  - SAF to SFO airport

LOWER RIVER UTILIZATION

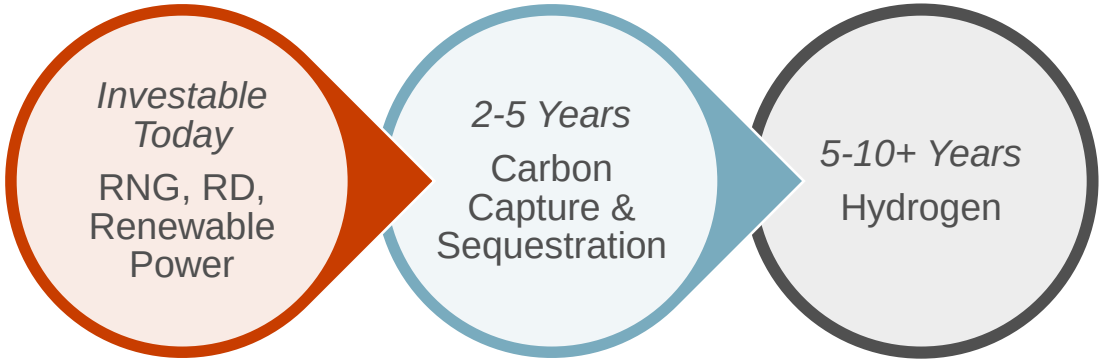


Benefitting from New Orleans' large veg oil market

- 3 mmbbl Harvey Terminal is part of our 5 mmbbl diversified chemical & vegetable oil Lower River hub
- Increasingly serving growing RD & RD feedstock market in Louisiana as well as international import/export
- Veg oils & other feedstocks often require heated storage, commanding premium rates

Newly-Formed Energy Transition Ventures (ETV) Group

The group will evaluate commercial opportunities emerging from the low-carbon energy transition



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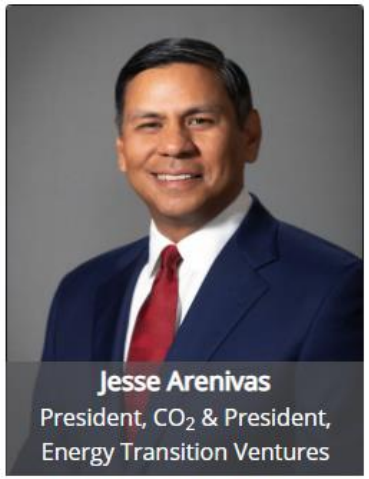
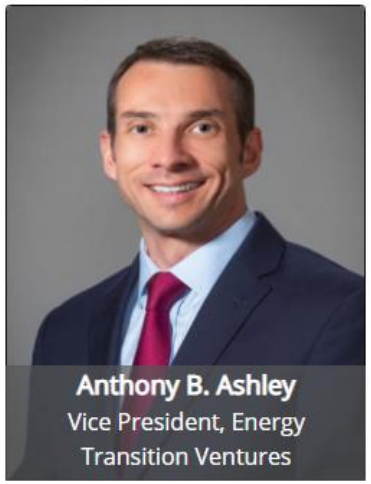




Opportunities for ETV group are outside of our existing asset base

Business segments will continue to pursue their own energy transition opportunities on existing assets

Most attractive opportunities likely to be synergistic with our existing infrastructure and expertise

Projects will have to compete for capital

Remain disciplined and focused on attractive returns exceeding cost of capital

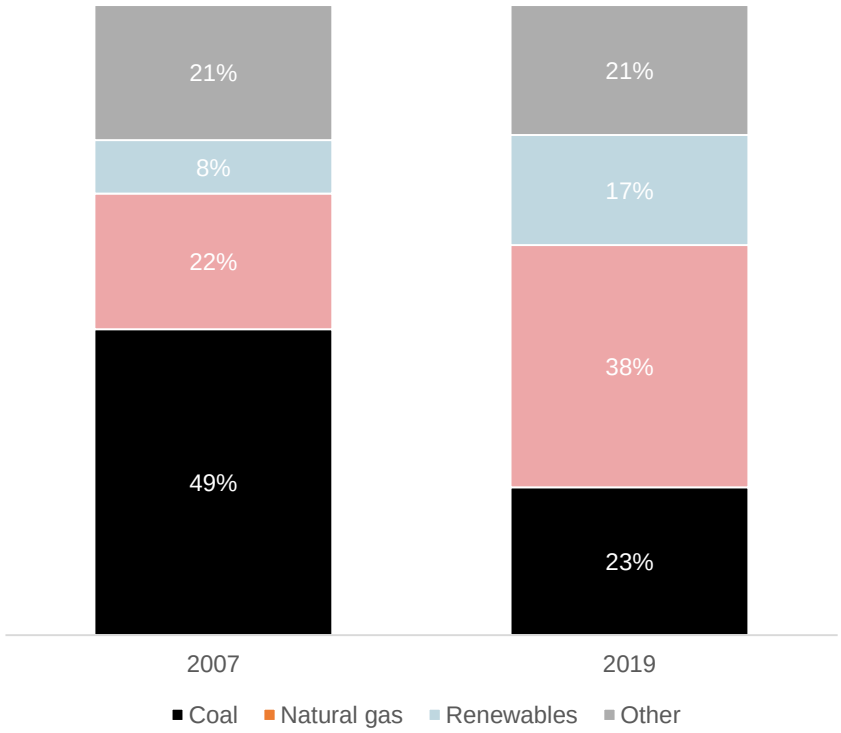
Acquired RNG developer Kinetrex Energy in 3Q 2021

U.S. CO_2 Emissions Declined Since 2007 while GDP grew ~50%

Primarily due to converting coal power generation to natural gas generation

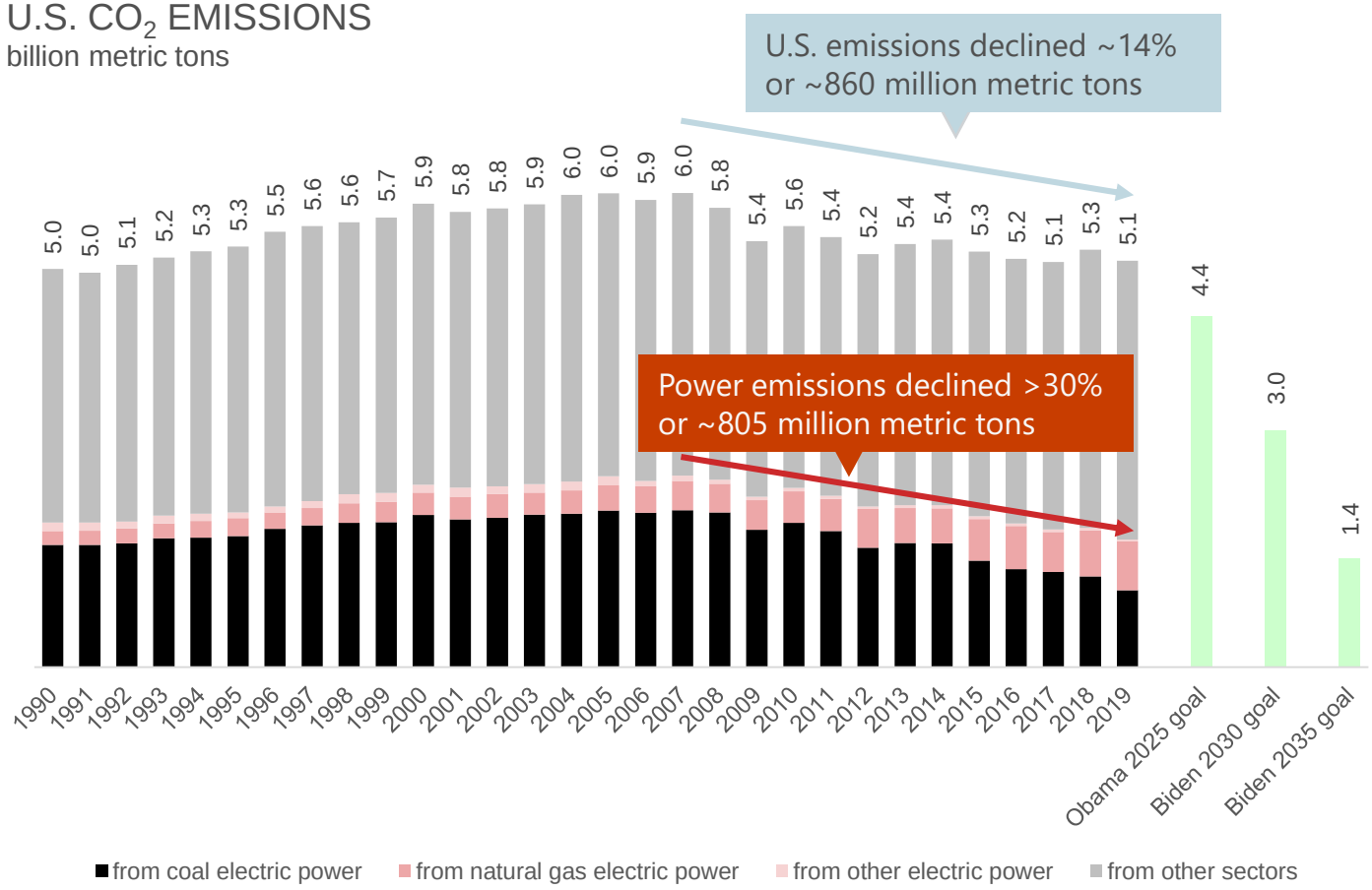
U.S. ELECTRICITY GENERATION MIX

% of total generation



U.S. CO_2 EMISSIONS

billion metric tons



Under the original Paris Agreement, U.S. was to reduce 2005-level CO_2 emissions 26-28% by 2025
By 2019, over half of that reduction goal was already achieved

Source: U.S. EIA Electricity Data Browser (net generation) & Monthly Energy Review (Dec-2020); World Bank, Development Indicators, GDP, U.S.$ current (12/16/2020).

RNG Provides an Immediate Low-Carbon Solution

Proven & cost-effective means of decarbonization

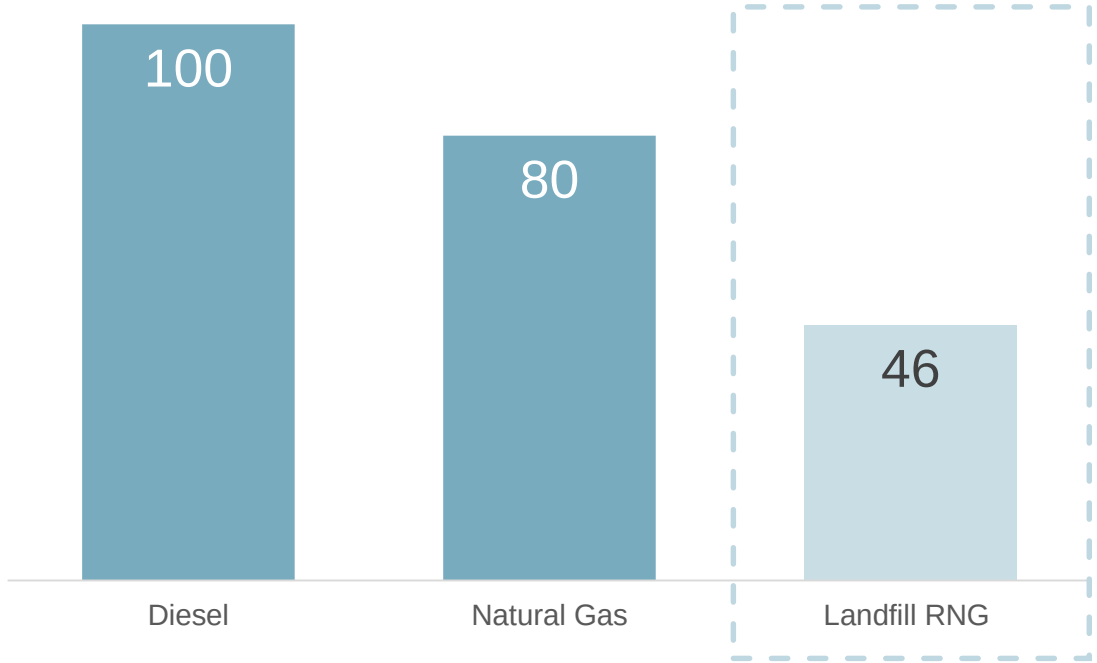
- Leverages existing natural gas infrastructure
- Utilizes reliable, low-cost feedstock
- Provides dispatchable and sustainable power
- Reduces fugitive emissions
- Promotes better waste management practices

U.S. Landfill RNG Projects Avoid Annual Emissions Equivalent to:

~2 billion	~218 million	~234 thousand
pounds of coal burned	gallons of gasoline consumed	homes' annual energy use

AVERAGE CARBON INTENSITY

gCO2e/MJ



RNG is a lower carbon alternative to natural gas

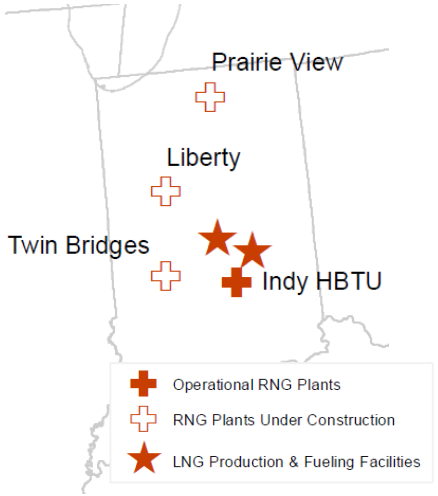
Source: EPA Landfill and LFG Energy Project Database, September 2021. Equivalencies based on the EPA greenhouse gas equivalencies calculator. Average carbon intensities per the RNG Coalition.

$310 million Acquisition of Kinetrex Energy

Platform acquisition provides multi-year head start to participate in emerging RNG market

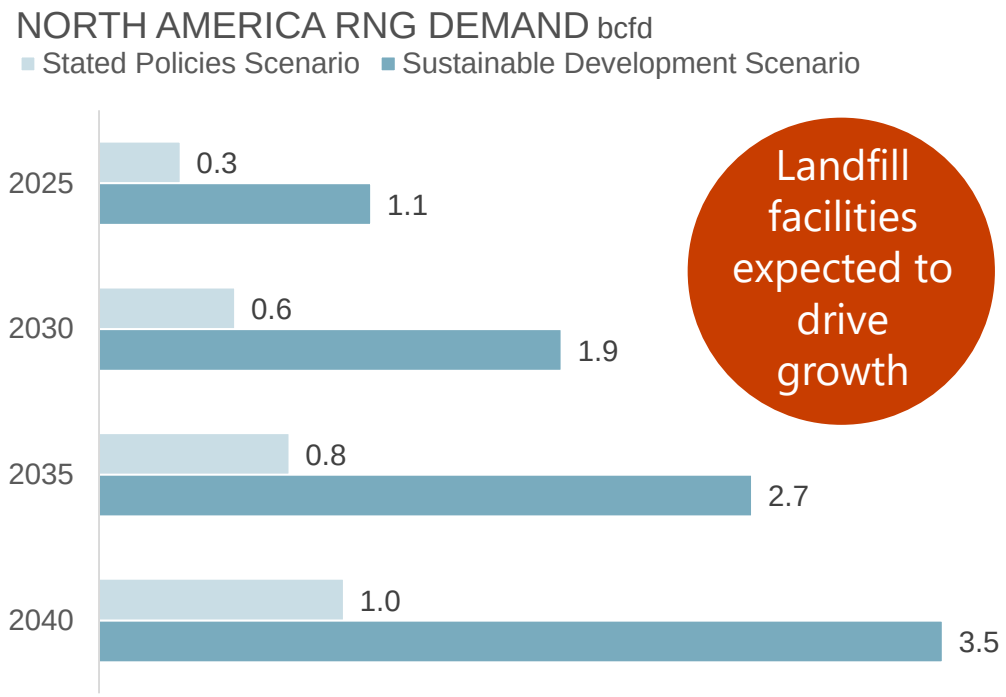
ASSETS & VALUATION

- 2 small-scale LNG facilities
- 1 operational landfill-RNG facility with ~0.4 bcf[(a)] capacity
- 3 landfill-RNG facilities operational by 2022 end with total capacity of 3.5 bcf
- Offtake is commercially contracted with high quality counterparty
- Expect <6x 2023 EBITDA based on $310mm purchase price and $146mm development capex
- Conservative RINs assumptions vs current spot RINs prices
- Transaction closed Aug 20, 2021



FUTURE RNG DEVELOPMENTS

- Retained Kinetrex management team to pursue new projects and expand RNG platform
- Mitigate exposure to RIN volatility through fixed price contracts in voluntary market



Hundreds of landfills across the US are candidates for RNG
<100 sites operational or in development today

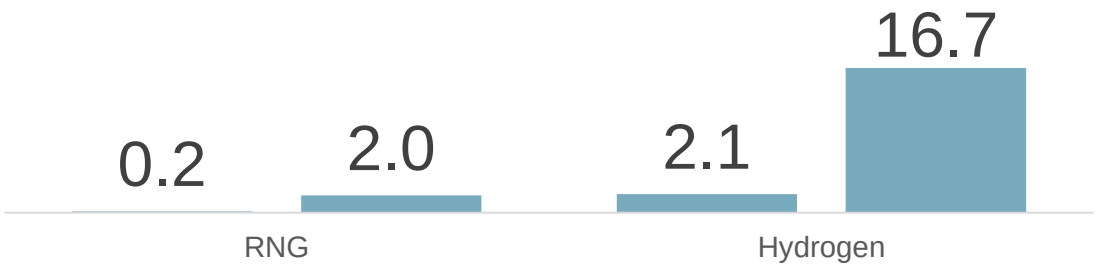
Sources: North America RNG Demand per IEA "Outlook for biogas and biomethane" report (March 2020).

a) KM share. 50% interest in Indy HBTU. 3 facilities in development are 100% owned.

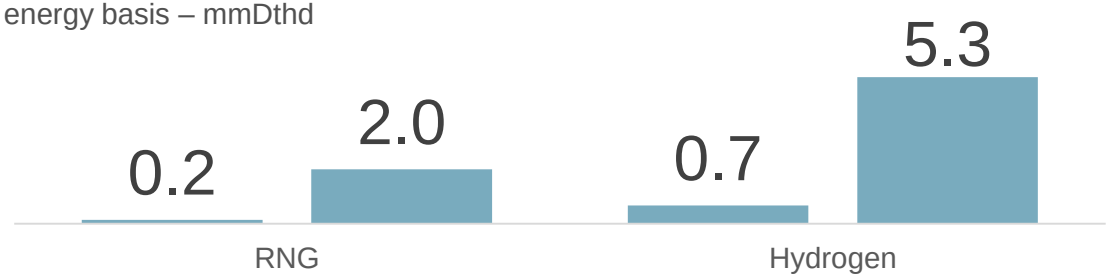
Attractive Potential for Renewable Fuels

U.S. RNG & HYDROGEN SUPPLY OUTLOOK 2020 & 2050 potential

volumetric basis – bcfd



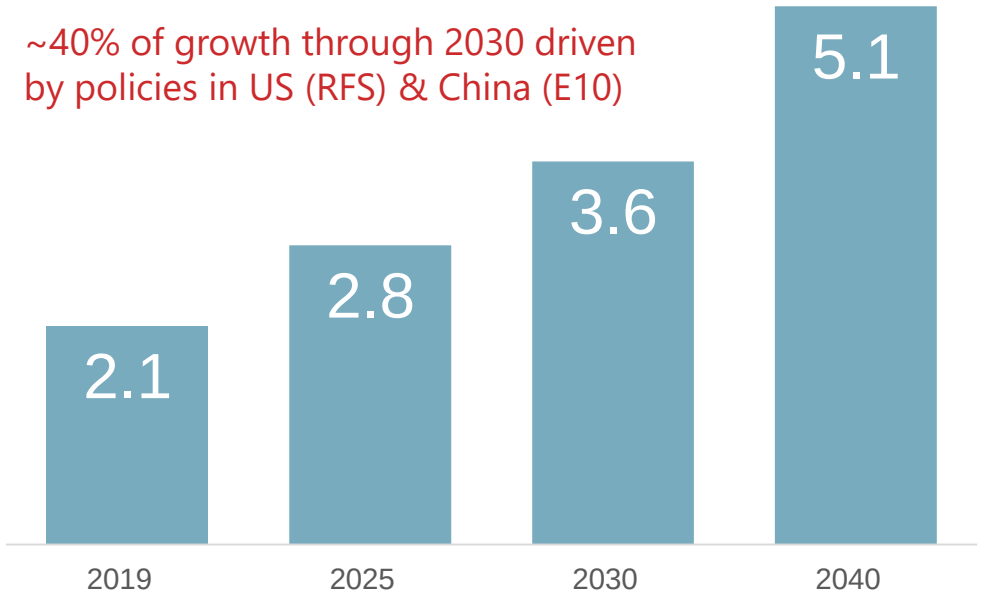
energy basis – mmDthd



The volumetric vs energy conversion illustrates that RNG is 3x more energy dense than hydrogen

Acquired RNG platform Kinetrex Energy

GLOBAL BIOFUELS DEMAND OUTLOOK mmbbld



Handled nearly 260 mbbld of ethanol, biodiesel, & renewable diesel in 2020, compared to 1 mmbld U.S. production

Evaluating opportunities to establish hubs for renewable feedstocks & biofuels

Source: U.S. RNG supply per WoodMackenzie Summer 2021 Long Term Outlook. 2020 U.S. hydrogen supply estimated from EIA. 2050 U.S. hydrogen supply potential from Hydrogen Council. "Hydrogen scaling up: A sustainable pathway for the global energy transition." November 2017.

Demand outlook per International Energy Agency, World Energy Outlook, October 2020 (Stated Policies Scenario). U.S. production from EIA Weekly U.S. Oxygenate Plant Production of Fuel Ethanol (1/6/2021) & Monthly Biodiesel Report (2/26/2021); RD production estimated based on EPA RIN data.

ESG Strategy

Provide energy services in a safe, efficient, and environmentally responsible manner for the benefit of people, communities, and businesses

environmental

Invest in low carbon future

- Grow natural gas business
- Invest in renewable fuels
- Leverage CCUS expertise & capabilities
- Energy Transition Ventures explores opportunities beyond our core business

Minimize environmental impact from our operations

- Reduce emissions
- Restore & protect biodiversity
- Safety-focused culture

social

Build & maintain relationships with stakeholders where we operate

Foster a diverse, inclusive, and respectful workplace

Support employee career development

Expect employees & representatives to adhere to our Code of Business Conduct and Ethics and Supplier Code of Conduct

governance

Risks & opportunities are continually monitored and communicated to leadership

Board evaluates long-term business strategy for resilience & adaptability

Board committees include EHS (including ESG), Audit, Compensation, and Nominating & Governance

Image of right-of-way on carbon-neutral Ruby pipeline

Recognized as an ESG Leader

Highly rated by multiple agencies

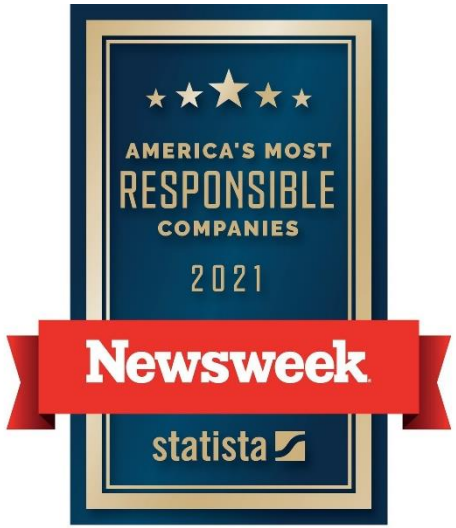
Sustainalytics #1
of 187 Refiners & Pipelines
of 101 Oil & Gas Storage & Transportation

FTSE #2
tied for #2 in
Oil & Gas Pipelines subsector

Refinitiv #7
of 202 Oil & Gas Related Equipment
and Services Companies

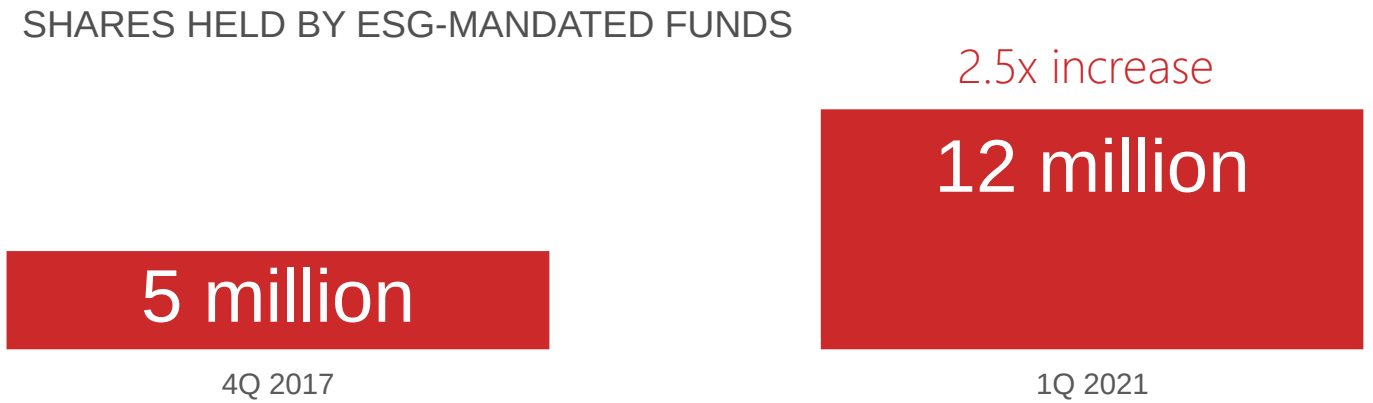
MSCI BBB
Oil & Gas Refining, Marketing, Transportation & Storage Industry

SSGA top 10%
R-Factor in
Oil & Gas – Midstream sector



Featured in several ESG indices FTSE4Good, MSCI USA ESG Leaders, S&P 500 ESG

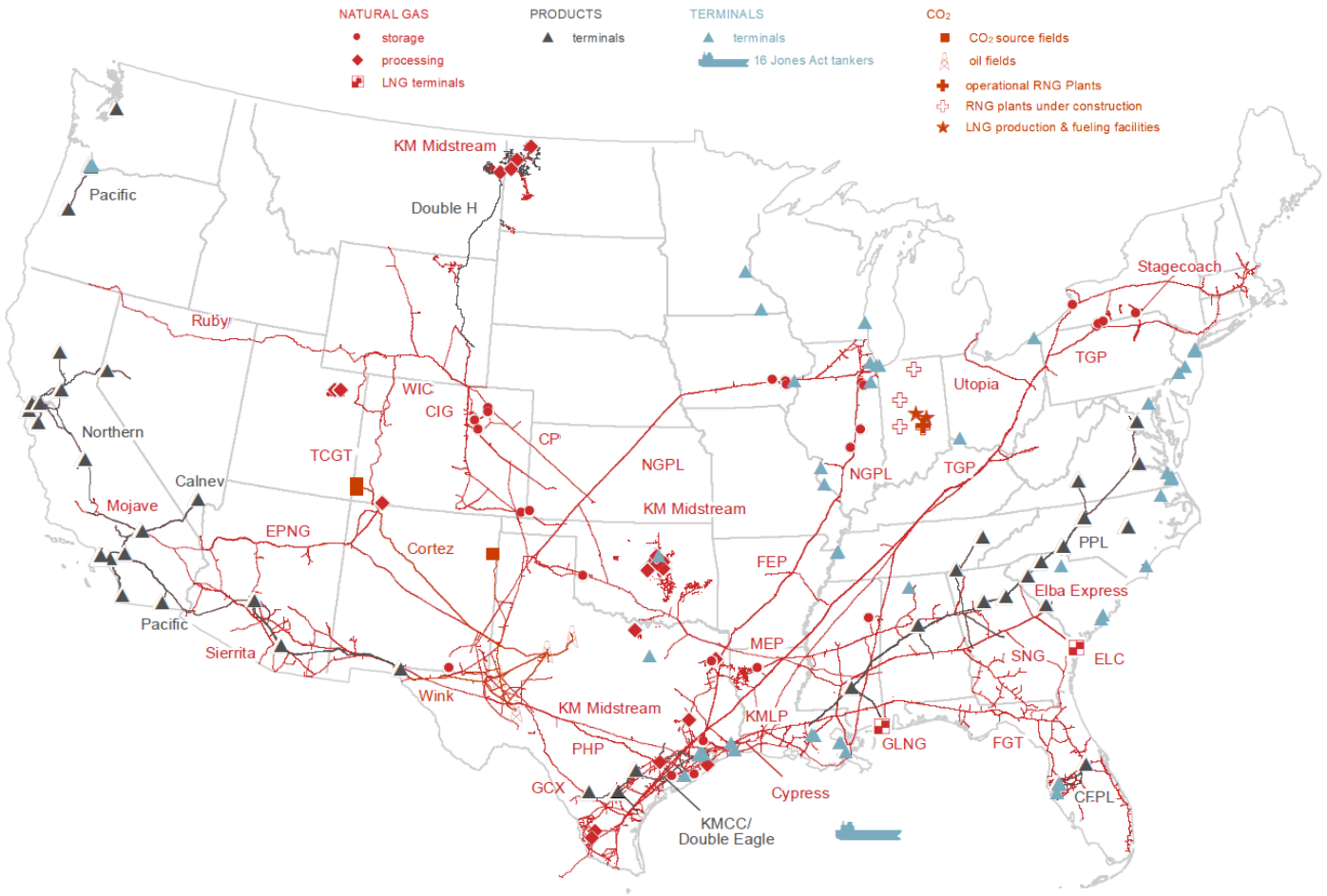
SHARES HELD BY ESG-MANDATED FUNDS



Note: Sustainalytics ESG risk rating as of 9/21/2021. FTSE ESG rating rank as of 7/27/2021. Refinitiv ESG score rank as of March 2021, scores to be updated later in 2021 to reflect RY2020. MSCI ESG rating as of December 2020. SSGA R-Factor as of 09/01/2021.

Compelling Investment Opportunity

Strategically-positioned assets generating substantial cash flow with attractive investment opportunities



- Stable cash flows with ~72% take-or-pay or hedged earnings[a]
- ~6% current yield & healthy dividend coverage
- Top 10 dividend yield in S&P500
- Dividends & capex funded with operating cash flow since 2016
- $1.4 billion of repurchase program remaining
- Highly-aligned management with ~13% share ownership

Positioned for energy future with a vast network of critical assets & low-carbon focus

a) Based on Adjusted Segment EBDA per 2021 budget. See Non-GAAP Financial Measures & Reconciliations.

APPENDIX

Energy Toll Road

Cash flow security with >90% from take-or-pay & other fee-based contracts

2021B EBDA %[a]	Natural Gas 62%			Products 16%		Terminals 15%			CO_2 7%	
	Interstate / LNG	Intrastate	G&P	Refined products	Crude	Liquids terminals	Jones Act tankers	Bulk terminals	EOR Oil & Gas	CO_2 & Transport
Asset Mix[a]	46%	10%	6%	11%	4% & 1% transport & G&P	9%	3%	3%	5%	2%
Volume Security[a]	93% take-or-pay	83% take-or-pay[b]	81% fee-based with minimum volume requirements and/or acreage dedications	primarily volume-based	transport: 69% take-or-pay G&P: 98% fee-based	74% take-or-pay	100% take-or-pay	primarily minimum volume guarantee or requirements	volume-based	effectively 84% minimum volume committed
Average Remaining Contract Life[c]	6.4 / 19.7 years	5.7 years[b]	2.5 years	generally not applicable	3.3 years	2.5 years	0.6 years	4.6 years	7.9 years	
Pricing Security	primarily fixed based on contract	primarily fixed margin	primarily fixed price	annual FERC tariff escalator (PPI-FG + 0.78%)	primarily fixed based on contract	based on contract; typically fixed or tied to PPI			volumes 81% hedged[d]	>95% protected by contractual price floors[a]
Regulatory Security	regulated return	essentially market-based	market-based	Pipelines: regulated return Terminals & transmix: not price regulated[e]		not price regulated			primarily unregulated	
Commodity Price Exposure	no direct exposure	limited exposure	limited exposure	limited exposure		no direct exposure			hedged / limited exposure	

a) Based on Adjusted Segment EBDA per the 2021 budget. See Non-GAAP Financial Measures & Reconciliations. Amounts have been rounded.
b) Includes term sale portfolio.
c) As of 1/1/2021
d) Percentage of 4Q 2021 forecasted oil & NGL net equity production.
e) Products terminals not FERC regulated, except portion of CALNEV.

$1.6 Billion Project Backlog as of 9/30/2021

Expect ~20% of backlog capital in service in 2021, ~40% in 2022, and ~30% in 2023

	DEMAND PULL	SUPPLY PUSH	CAPITAL ($ billion)	PIPELINE CAPACITY
Supply for U.S. power & LDC demand (TGP, FGT, SNG, TX intra)	●		$ 0.5	1.1 bcfd
Supply for LNG export (KMLP & EPNG)	●		0.2	1.4 bcfd
Gathering & processing (primarily Altamont, Hiland, KinderHawk)		●	0.2	various
Other natural gas	●	●	0.0	0.1 bcfd
Natural Gas			$ 0.8	
Products – includes $44 million RD projects		●	0.1	
Terminals – includes $65 million RD feedstock project		●	0.1	
Energy Ventures – $146 million RNG facilities			0.1	
CO_2		●	0.4	
Total backlog			$ 1.6	

Low-carbon investments represent 70% of backlog and expect average 3.6x EBITDA build multiple; investing in natural gas, RNG, and liquid biofuels infrastructure

Note: See Non-GAAP Financial Measures & Reconciliations. EBITDA multiple reflects KM share of estimated capital divided by estimated Project EBITDA.

2021 Forecast as of October 2021

Committed to maintaining a strong balance sheet & returning value to shareholders

Key metrics	2021 Forecast	Variance to 2021 Budget	
Net income	$1.7 billion	-$0.4 billion	Due primarily to 2Q $1.6 billion S Texas G&P impairment, partially offset by 1Q $1.1 billion Uri benefit
Adjusted EBITDA	$7.9 billion	+$1.1 billion	Due primarily to one-time benefit from Winter Storm Uri, as well as partial year contribution from Stagecoach acquisition
Distributable Cash Flow (DCF)	$5.4 billion	+$1.0 billion	
Discretionary capital[(a)]	$2.3 billion	+$1.5 billion	Due primarily to $1.2 billion Stagecoach acquisition and $0.4 billion Kinetrex acquisition & expansion capital
Dividend / share	$1.08	-	
Year-end Net Debt / Adj. EBITDA	4.0x	-0.6x	

Note: See Non-GAAP Financial Measures & Reconciliations.

a) Includes expansion capital, acquisitions, and JV contributions for expansion capital, debt repayments & net of partner contributions for our consolidated JVs.

Our Infrastructure is Important to Fueling the Future

Leveraging our long-term investment in the substantial assets & expertise required to responsibly deliver energy

BENEFITS OF NATURAL GAS

LOW EMISSIONS

Natural gas is the cleanest burning fossil fuel with significantly lower emissions than coal or fuel oil

Switching from coal to natural gas has driven a substantial reduction in U.S. power sector CO_2 emissions

Helps meet environmental targets

ABUNDANT & LOW COST

Cost-effective generation

Uses substantial infrastructure already in-place

Helps maintain affordability for consumers

RELIABLE

Provides energy supply when renewable sources are intermittent

Can be dispatched quickly

ENERGY DENSE & EFFICIENT

Less land area required compared to alternative energy sources

Helps avoid additional land disturbances

Natural gas enables economic growth without sacrificing environmental objectives
Our irreplaceable assets are essential to moving the fuels of today & tomorrow

Responsibly Sourced Natural Gas

Conventional natural gas produced by companies whose operations meet certain ESG standards

Standards typically focus on management practices for

methane emissions | water usage | community relations

25 producers have committed to begin RSG certification process on their production

these producers produce **~35 bcfd**[(a)]

Of the 25, 15 are ONE Future members that have committed to target a methane emission intensity of

0.28% of production by 2025

Currently reporting **0.085%**[(b)]

The 15 member companies produce nearly 20 bcfd[(a)]

>15% of our 2020 Natural Gas billings were to ONE Future members[(c)]

The market for responsibly sourced natural gas is expected to grow as consumers may increasingly desire that their natural gas be responsibly produced & transported

In discussions with **utilities & LNG** customers on **opportunities**

Recent partnerships on TGP & CIG with producers to transport their RSG to utilities

a) Based on most recent production data (August 2020 – July 2021)
b) 2019 rates reported in ONE Future 2020 Methane Emission Intensity Report for 10 member companies at the time.
c) Based on ONE Future membership as 2020 year end.

Reducing Methane Emissions for >25 Years

Natural gas is ~95% methane so we are economically incentivized to minimize methane emissions

monitor & repair

manage blow downs

Primary reduction strategies

- Conduct annual methane leak surveys and perform maintenance & repairs as needed
- Monitor performance of compressor components and replace as needed
- Due to occasional repairs or testing, natural gas must be evacuated from the pipeline (blowdown)
- Pumping down the pipeline first reduces natural gas vented during the blowdown
- Use sleeves and composite wraps which allow for external repair, avoiding blowdowns

Leader in methane emission reduction

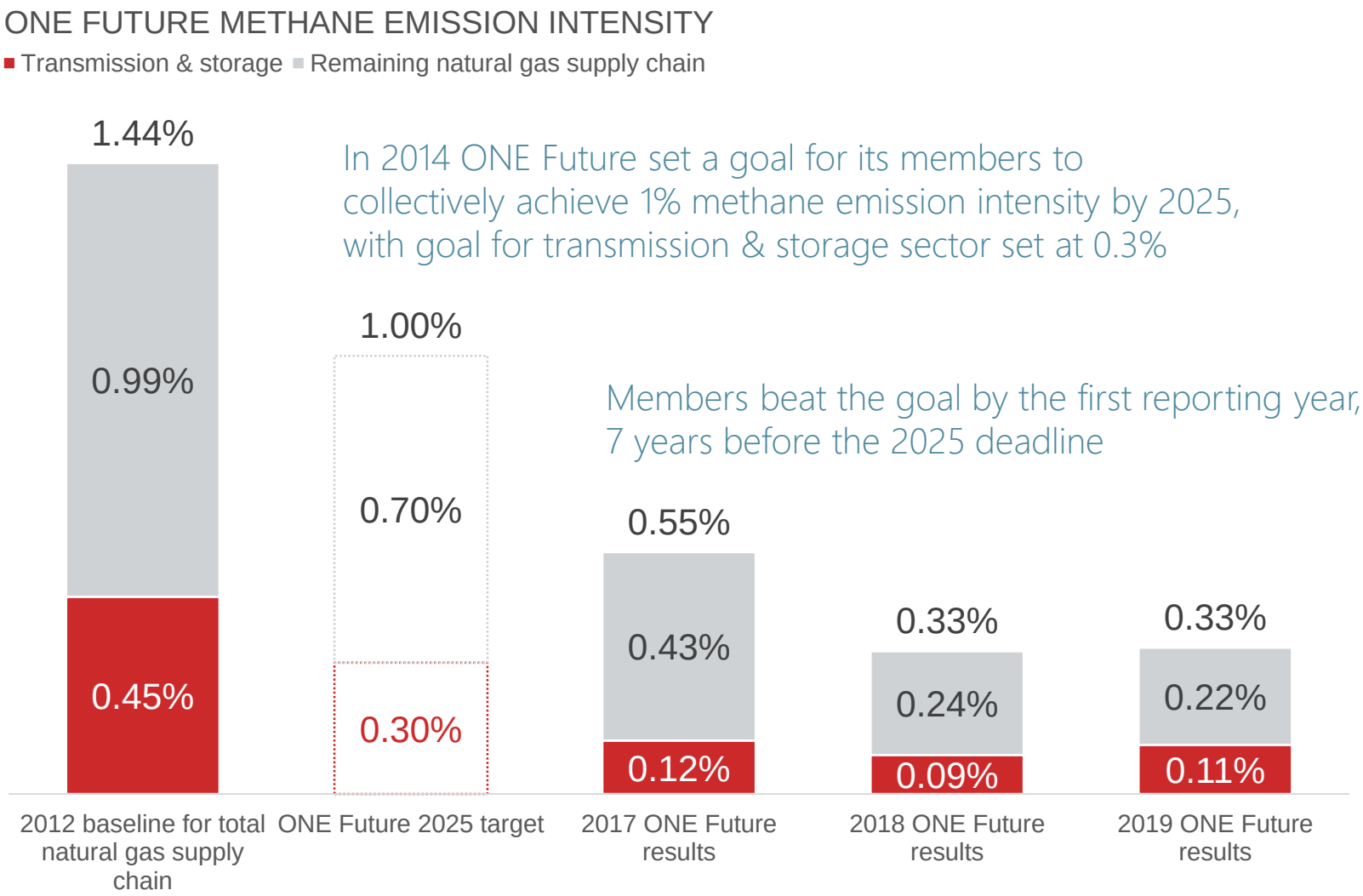
- Work with organizations like DOE, EPA, PRCI on studies & technology evaluations
- Implement detection technology like satellite & aerial methane detection, & laser absorption monitoring
- Active in methane reduction programs, including EPA programs & ONE Future

Technician using Optical Gas Imaging to survey for leaks at one of our KM Tejas compressor stations.

Note: DOE = Department of Energy. EPA = U.S. Environmental Protection Agency. PRCI = Pipeline Research Council International. EDF = Environmental Defense Fund.

ONE Future Proven Results

Beat goal 7 years early

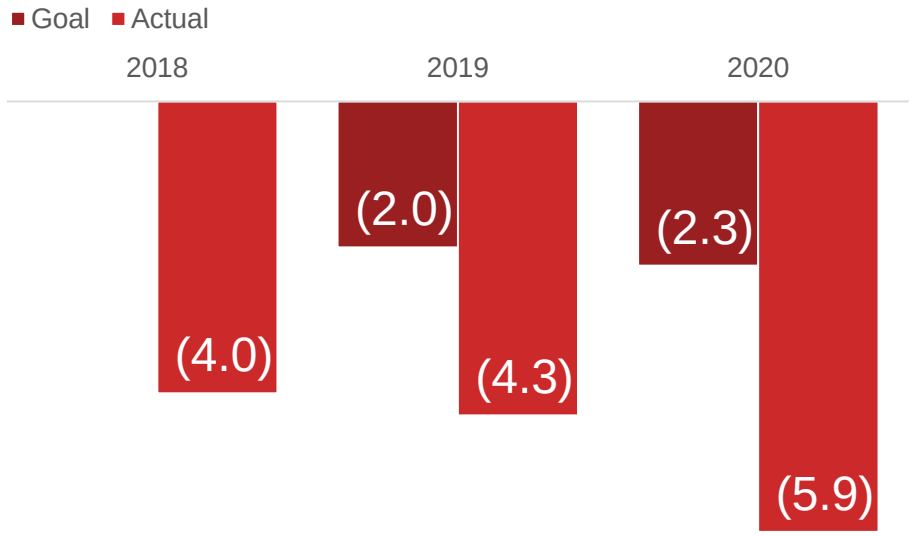


- ONE Future uses science-based technology and methods to reduce emissions across the natural gas supply chain
- Members establish best practices for methane management
- Leadership role alongside EPA to identify the most effective methane emission reduction methods
- Kinder Morgan founded ONE Future alongside 7 other companies in 2014; 50 members today

Note: Methane intensities shown are calculated as total methane emissions divided by gross natural gas production.

Long History of Methane Reduction Efforts

METHANE EMISSIONS REDUCTIONS bcf



Surpassed goals by >2x

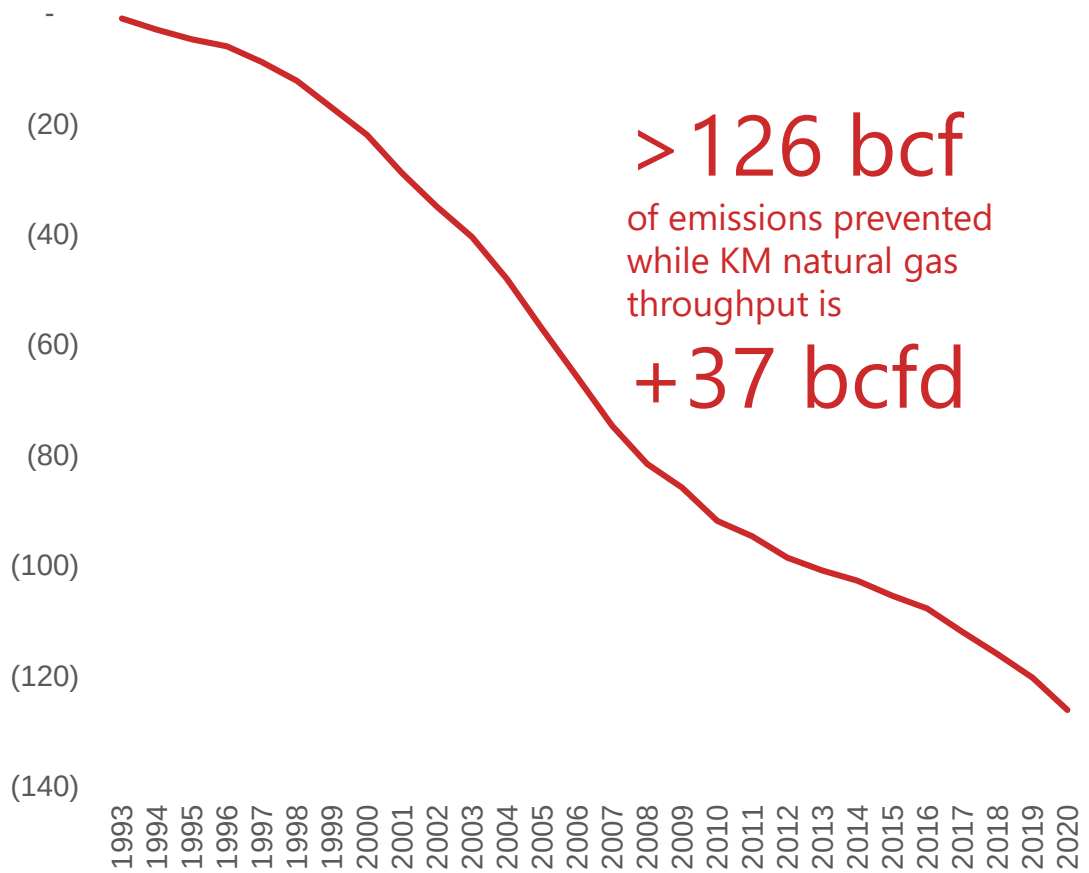
Continue to increase goal each year
2021 goal of 2.35 bcf
2022 goal of 2.50 bcf

Strong 2020 results due to

More leak repairs
Using more natural gas-fired turbines & electric compressors

CUMULATIVE METHANE EMISSIONS REDUCTIONS bcf

across our operations reported to EPA Natural Gas STAR & Methane Challenge



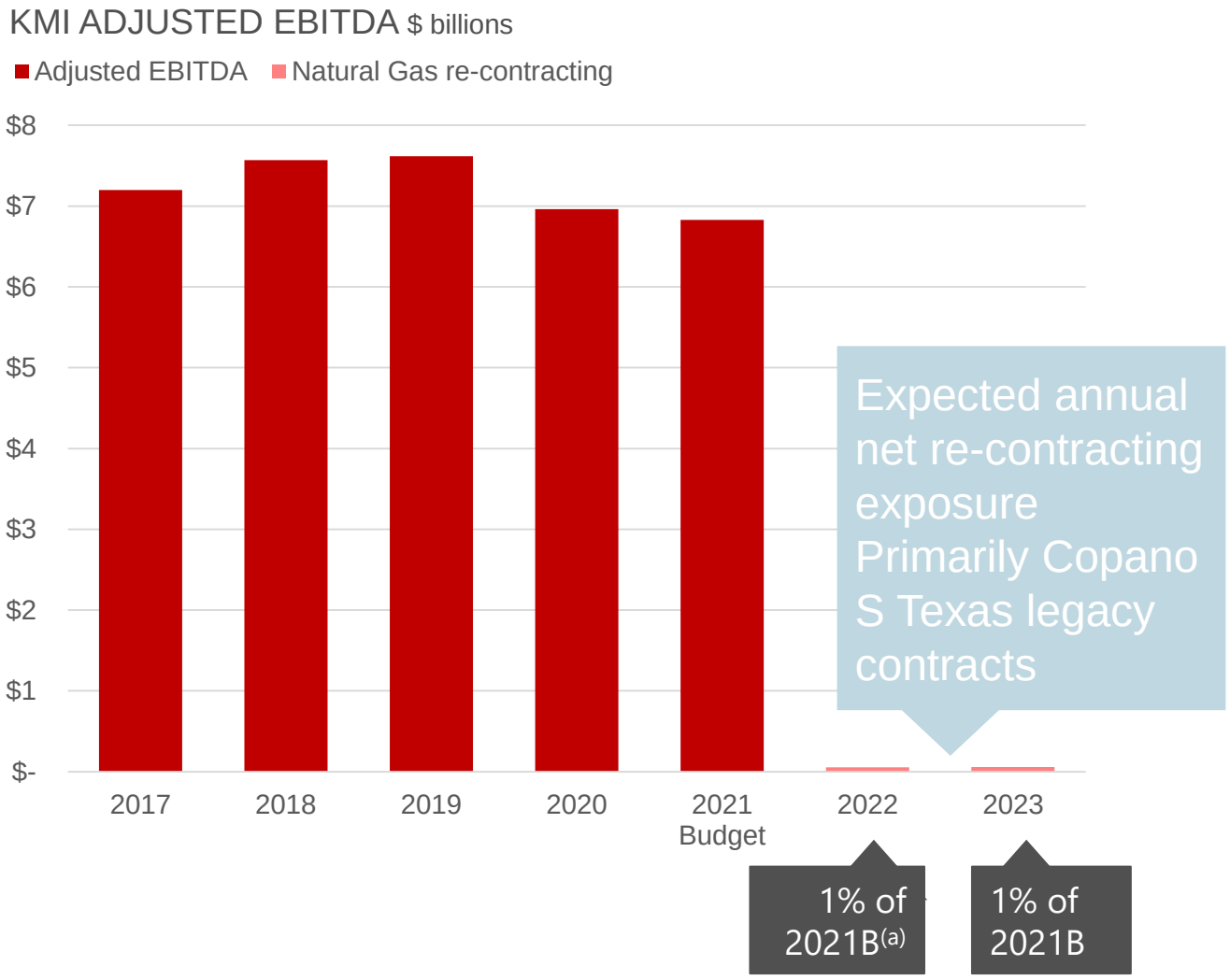
>126 bcf

of emissions prevented while KM natural gas throughput is

+37 bcfd

Manageable Natural Gas Re-Contracting Exposure

Analysis of existing contracts that renew during next two years



Expiring contracts are assessed for volumetric & rate risk based on November 2020 market assumptions (time of budget)(a)

Excludes benefit of new cash flows from growth projects

Excludes potential for re-purposing underutilized assets or otherwise enhancing service offerings

Contracts on natural gas pipelines have average remaining term of 6 years

Expect to more than offset re-contracting headwinds with growth projects underway, increases in usage, opportunities for currently uncontracted capacity & improved value for storage

Note: See Non-GAAP Financial Measures & Reconciliations for reconciliations of Adjusted EBITDA to its closest GAAP measure for 2020 and 2021 budget. For reconciliation of Adjusted EBITDA to its closest GAAP measure for the years 2017 through 2019, see KMI's Annual Reports on Form 10-K for the year-ended December 31, 2019 and 2018 filed with the Securities and Exchange Commission.

a) 2022 re-contracting exposure adjusted lower from previous estimate due to Ruby Pipeline risk that was brought forward to 2021

Gathering & Processing Assets Across Multiple Key Basins

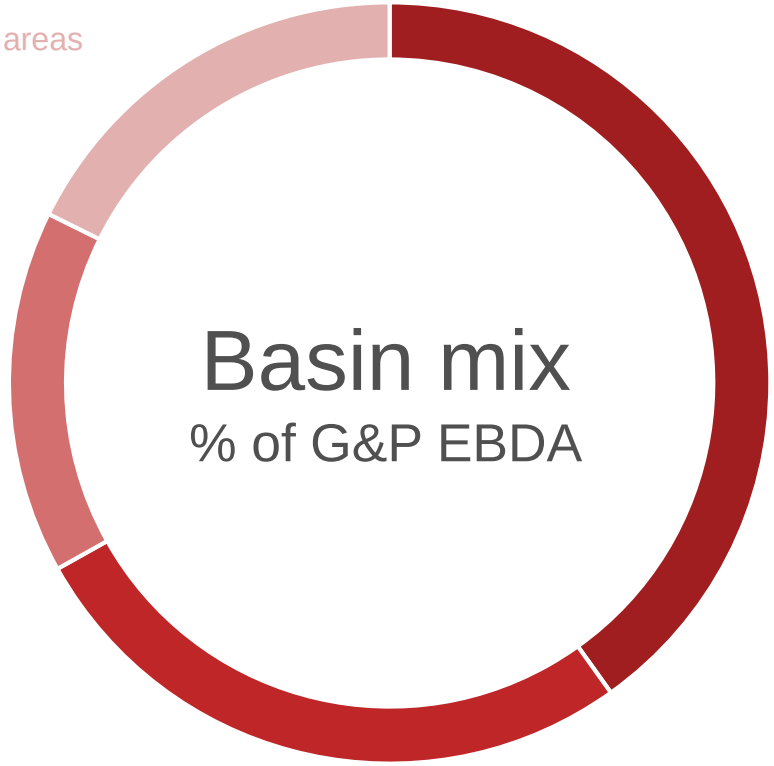
Represents ~7% of KMI EBDA with ~6% in Natural Gas & ~1% in Products (primarily Bakken)

~17% Other
Multiple systems in Uinta, Oklahoma, San Juan & other areas

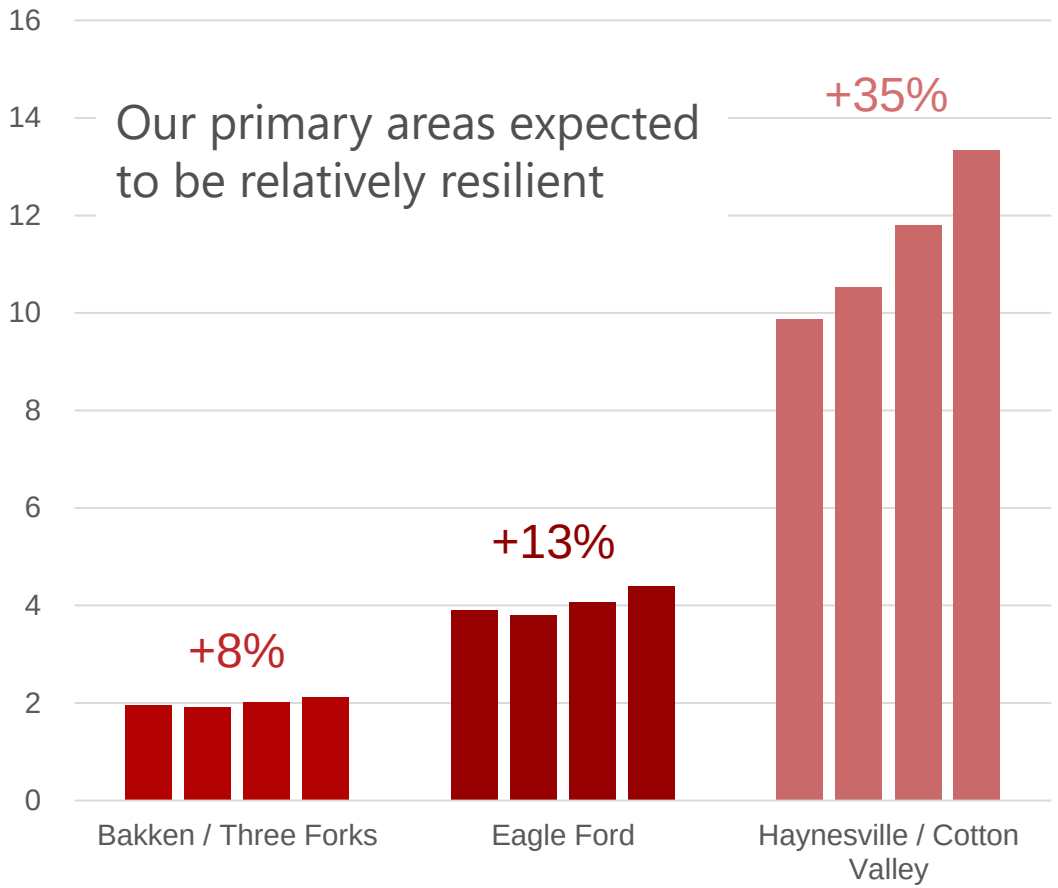
~13% Haynesville
KinderHawk assets with proximity to Gulf Coast industrial & LNG

~30% Bakken
Hiland system in core Williston acreage, including McKenzie County

~40% Eagle Ford
Copano South Texas & EagleHawk JV assets, primarily in LaSalle County



SHORT-TERM DRY GAS PRODUCTION OUTLOOK
bcfd, 2020 – 2023

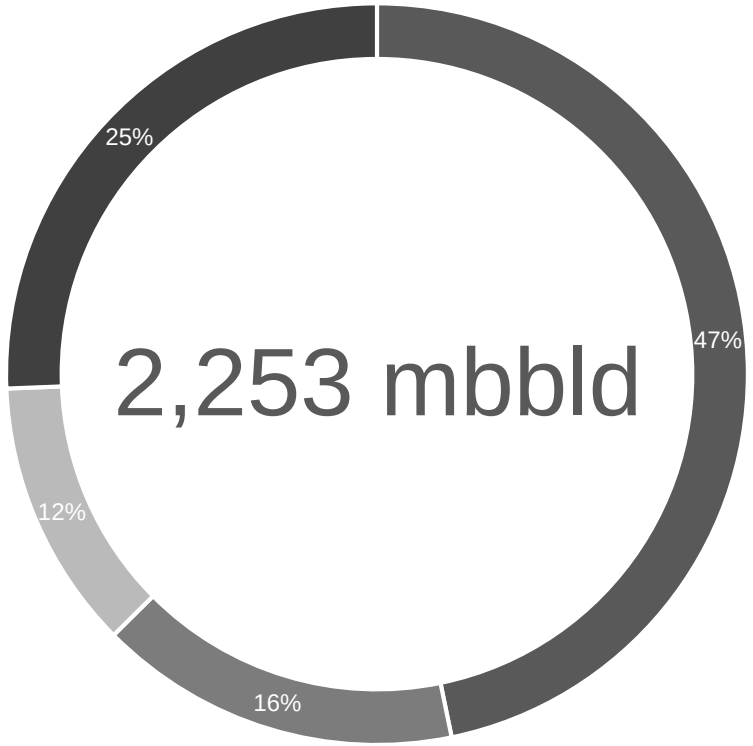


Note: Business mix based on Adjusted Segment EBDA per 2021 company budget. Includes assets in the Natural Gas & Products segments. See Non-GAAP Financial Measures & Reconciliations. Production outlook from Wood Mackenzie's North America Gas Short-Term Outlook (October 2021).

Products Segment Overview

Supplying a diverse mix of feedstock & finished products critical to refining & transportation sectors

2021B DELIVERY VOLUMES[a]



	2021B volumes mbbld	Volume by region[b]	
Gasoline	1,054	West 74% Southeast 26%	– Budget averages 2% below 2019 gasoline volumes & reaches 2019 level by Q4 2021
Diesel fuel	356	West 75% Southeast 25%	– Budget averages 2% below 2019 diesel volumes & reaches 2019 level by Q4 2021
Jet fuel	266	West 82% Southeast 18%	– Budget averages 12% below 2019 jet volumes & approaches 2019 level by Q4 2021 – Supplying airports in Atlanta, Las Vegas, Orlando, San Francisco, Washington D.C.
Crude oil	577	Bakken 51% Texas 49%	– Positioned in premier basins in Texas & North Dakota – KMCC provides access to Houston refining market & exports for Eagle Ford & Permian production – Hiland is one of the Bakken's premier gathering systems – Double H provides takeaway capacity from the Bakken to Cushing via joint tariff

Now forecasting refined products volumes to be slightly below budget for 2021

a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, PPL (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol.
b) Southeast Region Assets include Central Florida & PPL (KM share); West Region includes SFPP & CALNEV. Texas Crude Assets include KMCC, Camino Real, Double Eagle (KM share); Bakken Crude includes Double H & Hiland Crude Gathering.

Demand Markets Provide Diversification

Plan to mitigate exposure to RIN volatility through fixed price contracts in the voluntary market

REVENUE EXAMPLE

$ per mmbtu

revenues must meet or exceed

traditional hurdle rates

transportation market

RNG-based CNG & LNG is advantageous for fleets

- GHG emissions up to 75% less than diesel
- CNG vehicles are more efficient than electric vehicles for heavy & mid duty fleets looking to decarbonize
- Fleets are interested in RNG to meet emission reduction targets

RIN credits can be earned for RNG volumes used in the transportation market

- Drives the margin for RNG producers
- RFS-obligated parties (like refiners) purchase RINs to comply with RFS requirements

EPA considering creating eRINs to incentivize RNG used for electricity that charges electric vehicles

- Could create additional RNG demand and another avenue to capture RIN margin

voluntary market

LDCs, utilities, universities, industrial

- All active in the voluntary market today
- Showing increasing interest in RNG as they look to meet their emission reduction targets

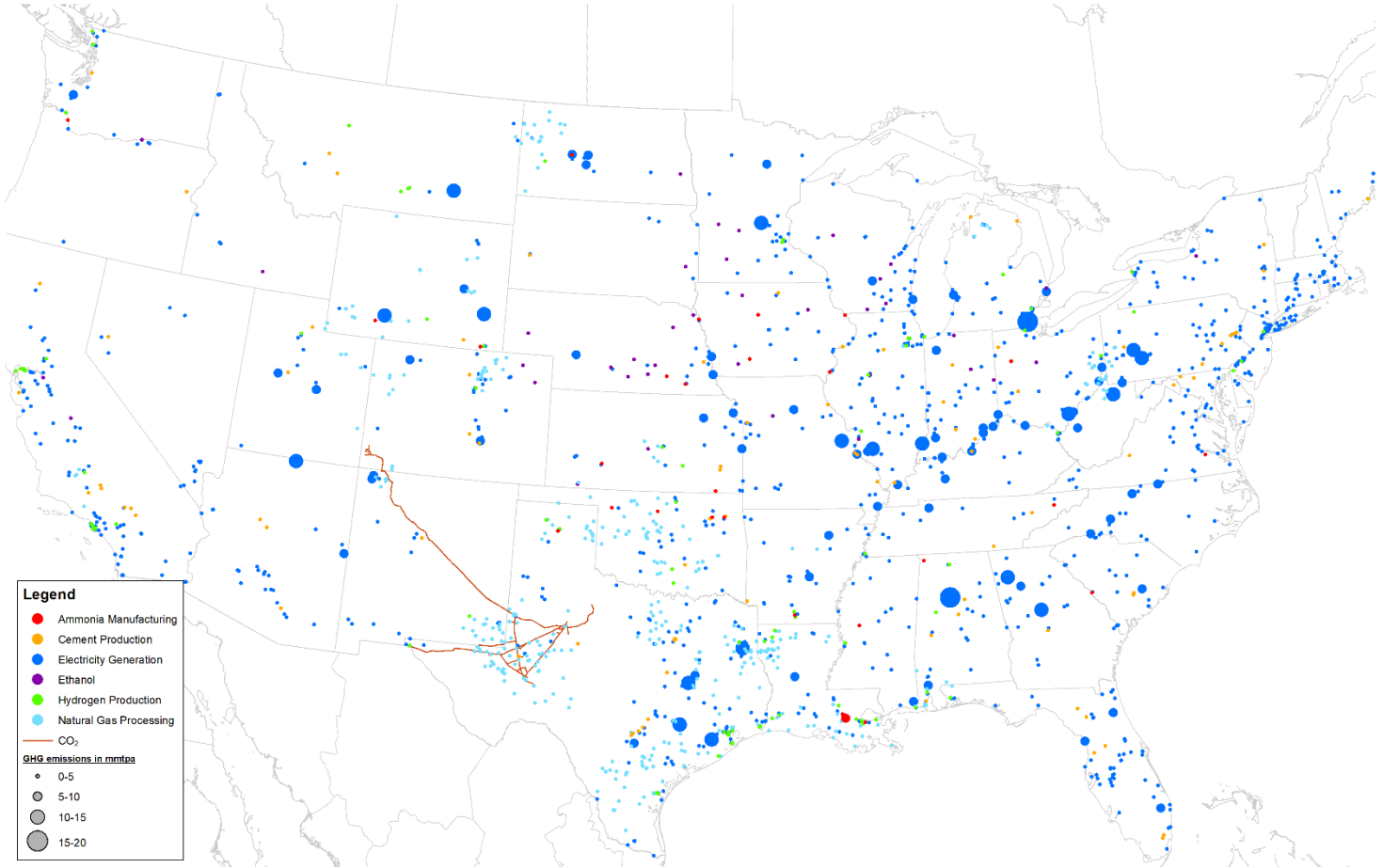
Pay premium for RNG

- Due to absence of subsidy for producers
- Pricing is lower than current RINs value but terms are generally fixed for 10+ years

a) $3.16 D3 RIN price (as of 7/23/2021, per Starfuels Brokerage via Bloomberg) multiplied by 11.727 to convert to $/mmbtu.

Captured Carbon may be Sequestered or used in EOR Production

Point source emitters are geographically diverse



Within 30 miles of our existing CO2 pipe, we estimate carbon capture opportunities of:

~200-300 mmcfd	from natural gas processing/treating
~500 mmcfd	from natural gas power
~700 mmcfd	from coal power

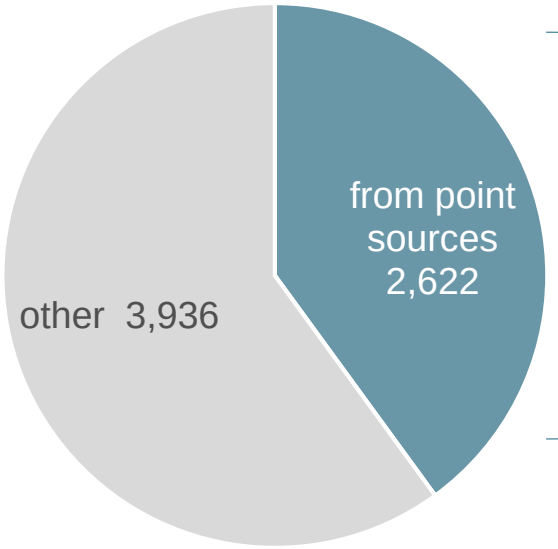
KMI is a natural fit for facilitating CCUS

Substantial EOR experience

Have been developing CO2 pipeline & processing facilities for decades

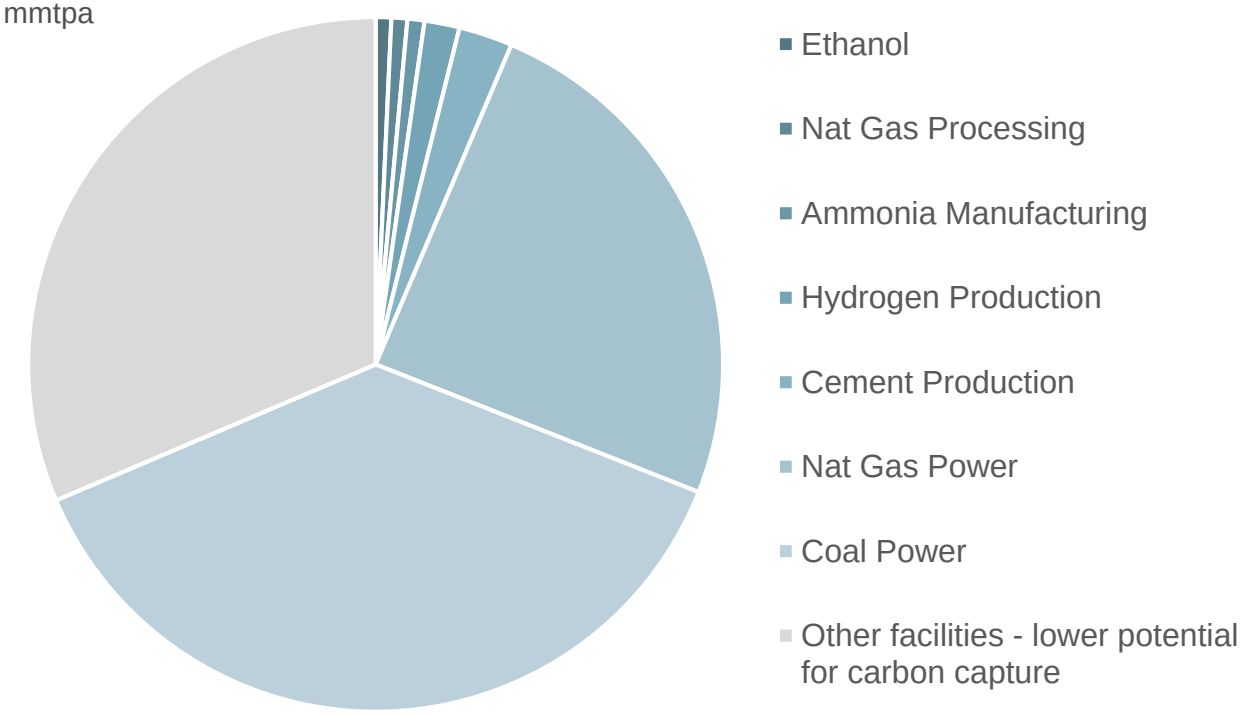
Opportunity to Capture Carbon from Stationary Sources

US GHG EMISSIONS
mmtpa



~70% of point source emissions are higher potential candidates for carbon capture

US GHG EMISSIONS FROM POINT SOURCES
mmtpa



CAPTURE OPPORTUNITY…

- ~1,800 mmtpa, or >90 bcfd, GHG emissions associated with facilities that could be candidates for carbon capture
- Ethanol facilities and natural gas processing/treating facilities may be economic today under current 45Q
- Together, these emissions represent ~2 bcfd of CO2 potential

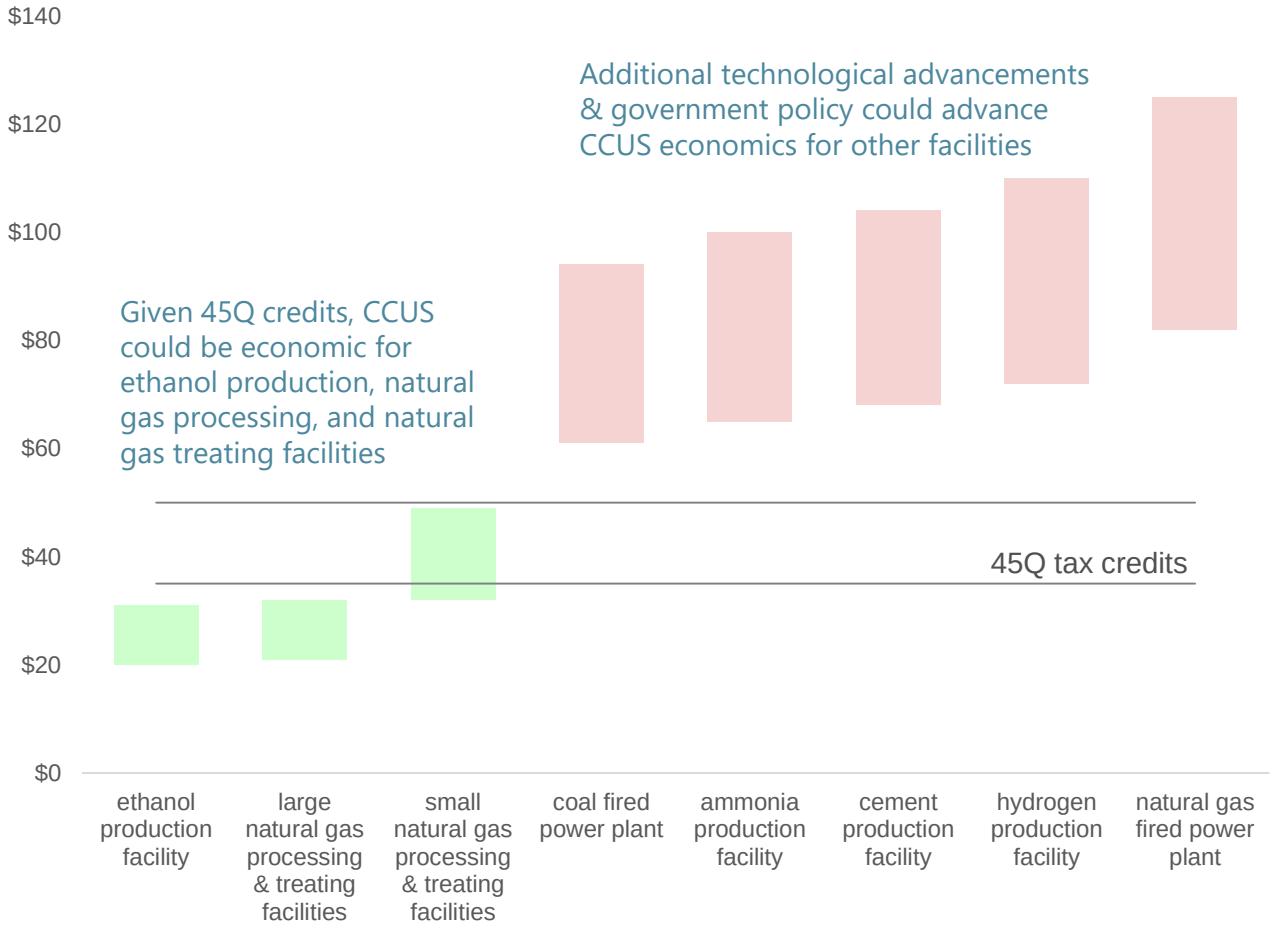
…IS TEMPERED BY

- Facilities are spread out geographically; aggregation is challenged
- CO2 purity stream varies by facility type, impacts economics
- Power plants are larger scale opportunities but capture requires high uptime factor, problematic for natural gas peakers
- Additionally, coal power plants could face nearer-term retirement

Source: EPA GHG Inventory Report and EPA GHG Reporting Program.

CCUS Economics are Improving but Remain Challenged

CURRENT ESTIMATED U.S. CARBON CAPTURE COST $/tonne



45Q TAX CREDITS

- Capturer controls the tax credit
- Industry still contemplating economics across the value chain
- Proposed direct pay option could be a catalyst for CCUS

SEQUESTRATION

- $50/tonne deductible tax credit starting in 2027
- Lengthy EPA permitting process; only 2 permits ever issued
- States considering regulatory primacy to shorten permitting process, including Texas
- Our source fields in Colorado could potentially be used for sequestration in the future

EOR

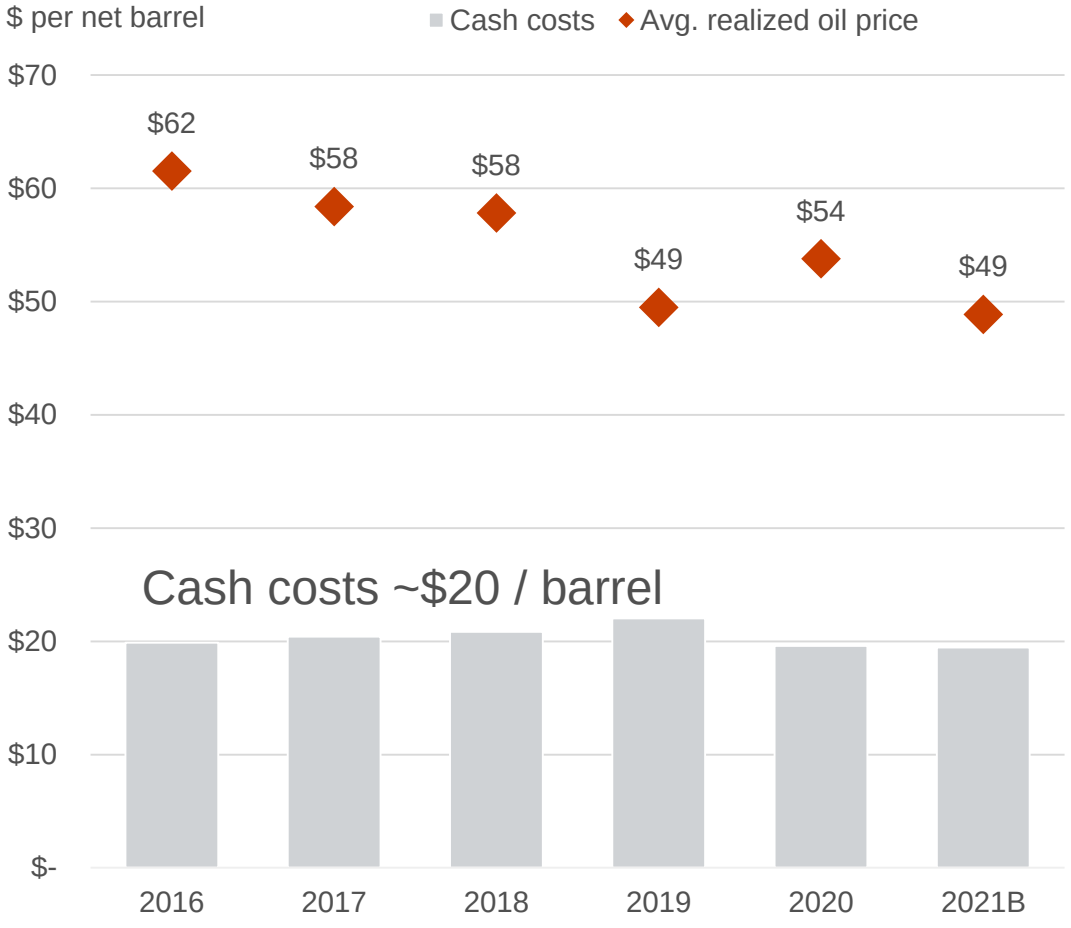
- $35/tonne tax credit (beginning in 2027) is lower than for sequestration, but more feasible today
- Our 1.5 bcfd Cortez pipeline delivers ~80% of the CO2 used for Permian EOR

Source: KM analysis, National Energy Technology Laboratory.
Note: Estimated costs are based on 20% BFIT IRR at capture unit tailgate, no tax credits, and at pressure ready for pipeline.

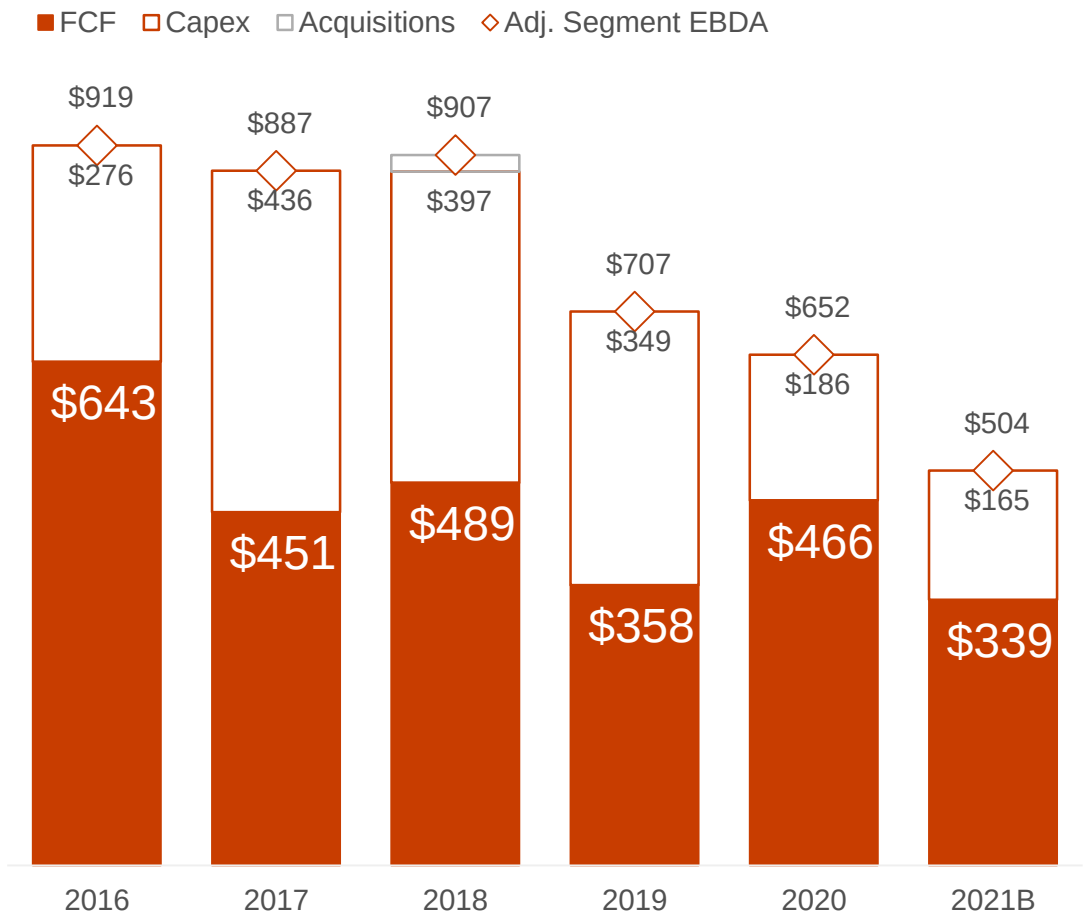
CO_2 Segment Consistently Generates Free Cash Flow

Low cash cost structure yields healthy margins through multiple commodity price cycles

OIL & GAS CASH OPERATING COSTS & AVG. PRICE



CO_2 SEGMENT FREE CASH FLOW $ millions



Note: Cash costs & revenue per net oil barrel, including hedges where applicable. See Non-GAAP Financial Measures & Reconciliations for CO_2 Free Cash Flow.

Joint Venture Treatment in Key Metrics

	KM does not control nor consolidate KM portion referred to as equity investments in financial statements	**KM controls & fully consolidates** third party portion referred to as noncontrolling interests in financial statements	
Example JVs	SNG (50%), NGPL (37.5%), GCX (26.7%) Please see Note 7 in our 10K for full list	Elba Liquefaction (51%), BOSTCO (55%)	
Financial Metrics	Earnings from Equity Investments *KM share of JV Net Income* **Net Income & Segment EBDA** + Certain Items *KM share* **Adjusted Segment EBDA** + DD&A + Book Taxes *KM share* **Adjusted EBITDA** - Cash Taxes - Sustaining Capex *KM share* **Distributable Cash Flow (DCF)**	Consolidated throughout income statement *100% of JV* **Net Income** + DD&A + G&A and Corporate Charges + Interest Expense + Book Taxes *100% of JV* **Segment EBDA** + Certain Items *100% of JV* **Adjusted Segment EBDA**	Consolidated throughout income statement *100% of JV* **Net Income** - Net Income Attributable to Noncontrolling Interests **Net Income Attributable to Kinder Morgan, Inc.** + DD&A + Book Taxes + Interest Expense + Certain Items *KM share* **Adjusted EBITDA** - Interest Expense - Cash Taxes - Sustaining Capex *KM share* **Distributable Cash Flow (DCF)**
Debt	**No JV debt included** JV's Adjusted EBITDA contribution is after subtracting interest expense	**100% of JV debt included, if any** fully consolidated on balance sheet	
Sustaining Capital	**Includes KM owned % of JV sustaining capital**		
Discretionary Capital	**Includes KM contributions to JVs based on % owned, including for projects & debt repayment**		

Note: See Non-GAAP Financial Measures & Reconciliations.

Non-GAAP Financial Measures & Reconciliations

Defined Terms

Reconciliations for the historical periods

Use of Non-GAAP Financial Measures

We use the non-GAAP financial measures of Adjusted Earnings and Distributable Cash Flow (or DCF), both in the aggregate and per share for each; Adjusted Segment EBDA; Adjusted EBITDA; Net Debt; Net Debt to Adjusted EBITDA; Project EBITDA; Free Cash Flow; and CO_2 Segment Free Cash Flow.

Our non-GAAP financial measures described further below should not be considered alternatives to GAAP net income attributable to Kinder Morgan, Inc. 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.

We do not provide (i) budgeted revenue (the GAAP financial measure closest to net revenue) due to impracticality of predicting certain amounts required by GAAP, including projected commodity prices at the multiple purchase and sale points across certain intrastate pipeline systems; however, we are able to project the net revenue received for transportation services based on contractual agreements and historical operational experience; (ii) budgeted CO_2 Segment EBDA (the GAAP financial measure most directly comparable to 2021 budgeted CO_2 Segment Free Cash Flow) due to the inherent difficulty and impracticability of predicting certain amounts required by GAAP, such as potential changes in estimates for certain contingent liabilities and unrealized gains and losses on derivatives marked to market; or (iii) the portion of budgeted net income attributable to individual capital projects (the GAAP financial measure most directly comparable to Project EBITDA) due to the impracticality of predicting, on a project-by-project basis through the second full year of operations, certain amounts required by GAAP, such as projected commodity prices, unrealized gains and losses on derivatives marked to market, and potential estimates for certain contingent liabilities associated with the project completion.

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 attributable to Kinder Morgan, Inc., but typically either (i) do not have a cashimpact (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).

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 business’s 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 share.

DCF is calculated by adjusting net income attributable to Kinder Morgan, Inc. for Certain Items (or Adjusted Earnings, as defined above), 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 beused for discretionary purposes such as dividends, stock repurchases, retirement of debt, or expansion capital expenditures. DCF should not be used as an alternative to net cash provided byoperating activities computed under GAAP. We believe the GAAP measure most directly comparable to DCF is net income attributable to Kinder Morgan, Inc. DCF per share is DCF divided by average outstanding shares, including restricted stock awards that participate in dividends.

Use of Non-GAAP Financial Measures (Continued)

Adjusted Segment EBDA is calculated by adjusting segment earnings before DD&A and amortization of excess cost of equity investments (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. General and administrative expenses and certain corporate charges are generally not under the control of our segment operating managers, and therefore, are not included when we measure business segment operating performance. 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 assesseach segment's performance. We believe the GAAP measure most directly comparable to Adjusted Segment EBDA is Segment EBDA.

Adjusted EBITDA is calculated by adjusting net income attributable to Kinder Morgan, Inc. before interest expense, income taxes, DD&A, and amortization of excess cost of equity investments (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 conjunctionwith 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 attributable to Kinder Morgan, Inc.

Amounts from Joint Ventures - Certain Items, DCF and Adjusted EBITDA reflect amounts from unconsolidated joint ventures (JVs) and consolidated JVs utilizing the same recognition and measurement methods used to record "Earnings from equity investments" and "Noncontrolling interests(NCI)," respectively. The calculations of DCF and Adjusted EBITDA related to our unconsolidated and consolidated JVs include the same items (DD&A and income tax expense, and for DCF only, also cash taxes and sustaining capital expenditures) with respect to the JVs as those included in the calculations of DCF and Adjusted EBITDA for our wholly-owned consolidated subsidiaries. Although these amounts related to our unconsolidated JVs 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 JVs. DCF and Adjusted EBITDA are further adjusted for certain KML activities attributable to our NCI in KML for the periods presented through KML's sale on December 16, 2019.

Net Debt is calculated by subtracting from debt (i) cash and cash equivalents, (ii) the preferred interest in the general partner of Kinder Morgan Energy Partners L.P. (which was redeemed in January 2020), (iii) debt fair value adjustments, and (iv) the foreign exchange impact on Euro-denominated bonds for which we have entered into currency swaps. Net Debt is a non-GAAP financial measure that management believes is useful to investors and other users of our financial information in evaluating our leverage. We believe the most comparable measure to Net Debtis debt net of cash and cash equivalents.

Project EBITDA is calculated for an individual capital project as earnings before interest expense, taxes, DD&A and general and administrative expenses attributable to such project, or for JV projects, consistent with the methods described above under "Amounts from Joint Ventures." Management uses Project EBITDA to evaluate our return on investment for capital projects before expenses that are generally not controllable by operating managers in our business segments. We believe the GAAP measure most directly comparable to Project EBITDA is the portion of net income attributable to a capital project.

Free Cash Flow is calculated by adjusting cash flow from operations for capital expenditures. Free Cash Flows is used by external users as an additional leverage metric. Therefore, we believe Free Cash Flow is useful to our investors. We believe the GAAP measure most directly comparable to Free Cash Flow is cash flow from operations.

CO_2 Segment Free Cash Flow is calculated by reducing Segment EBDA (GAAP) for our CO_2 business segment by Certain Items, capital expenditures (sustaining and expansion) and acquisitions attributable to the segment. Management uses CO_2 Segment Free Cash Flow as an additional performance measure for our CO_2 business segment. We believe the GAAP measure most directly comparable to CO_2 Segment Free Cash Flow is Segment EBDA (GAAP) for our CO_2 business segment.

GAAP Reconciliations

$ in millions

	2021 Projected Guidance	2020 Actual
Net income attributable to Kinder Morgan, Inc. (GAAP)	**$ 1,700**	**$ 119**
Total Certain Items	1,200	1,892
Adjusted Earnings[a]	**2,900**	**2,011**
DD&A and amortization of excess cost of equity investments for DCF[b]	2,600	2,671
Income tax expense for DCF[a,b]	900	670
Cash taxes[c]	(100)	(68)
Sustaining capital expenditures[d]	(900)	(658)
Other items[e]	-	(29)
DCF	**$ 5,400**	**$ 4,597**

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Amounts are adjusted for Certain Items.

b) Includes DD&A or income tax expense, as applicable, from JVs.

c) 2020 includes cash taxes from JVs of $62 million

d) 2020 includes sustaining capital expenditures from JVs of $114 million

e) 2020 includes non-cash pension expense and non-cash compensation associated with our restricted stock

	2021 Projected Guidance	2020 Actual
Net income attributable to Kinder Morgan, Inc. (GAAP)	**$ 1,700**	**$ 119**
Total Certain Items	1,200	1,892
DD&A and amortization of excess cost of equity investments	2,200	2,304
Income tax expense[a]	800	588
JV DD&A and income tax expense[a,b]	500	449
Interest, net[a]	1,500	1,610
Adjusted EBITDA	**$ 7,900**	**$ 6,962**

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Amounts are adjusted for Certain Items.

b) Represents DD&A and income tax expense from JVs.

Reconciliation of DD&A and amortization of excess cost of equity investments for DCF	2020
Depreciation, depletion and amortization (GAAP)	($2,164)
Amortization of excess cost of equity investments (GAAP)	(140)
DD&A and amortization of excess cost of equity investments	(2,304)
JV DD&A	(367)
DD&A and amortization of excess cost of equity investments for DCF	($2,671)

Reconciliation of general and administrative and corporate charges	
General and administrative (GAAP)	($648)
Corporate charges	(5)
Certain Items	92
General and administrative and corporate charges[a]	($561)

Reconciliation of interest, net	
Interest, net (GAAP)	$ (1,595)
Certain Items	(15)
Interest, net[a]	$ (1,610)

Reconciliation of income tax expense for DCF	2020
Income tax expense (GAAP)	$ (481)
Certain Items	(107)
Income tax expense[a]	(588)
Unconsolidated JV income tax expense[b]	(82)
Income tax expense for DCF[a]	$ (670)

Reconciliation of additional JV information	
Unconsolidated JV DD&A	$ (407)
Less: Consolidated JV partners' DD&A	(40)
JV DD&A	(367)
Unconsolidated JV income tax expense[a,b]	(82)
JV DD&A and income tax expense[a]	$ (449)
Unconsolidated JV cash taxes[b]	$ (62)
Unconsolidated JV sustaining capital expenditures	$ (120)
Less: Consolidated JV partners' sustaining capital expenditures	(6)
JV sustaining capital expenditures	$ (114)

a) Amounts are adjusted for Certain Items.

b) Amounts are associated with our Citrus, NGPL and Plantation equity investments.

GAAP Reconciliations

$ in millions

Reconciliation of Adjusted Segment EBDA	2020 Segment EBDA (GAAP)	2020 Certain Items in Adjusted Segment EBDA	2020 Adjusted Segment EBDA
Natural Gas Pipelines	$3,483	$983	$4,466
Products Pipelines	977	50	1,027
Terminals	1,045	(55)	990
CO_2	(292)	944	652
Total	$5,213	$1,922	$7,135

Reconciliation of Net Debt	2020
Outstanding long-term debt	$ 30,838
Current portion of debt	2,558
Foreign exchange impact on hedges for Euro Debt outstanding	(170)
Less: cash & cash equivalents	(1,184)
Net Debt	$ 32,042
Adjusted EBITDA	$ 6,962
Net Debt to Adjusted EBITDA	**4.6X**

Certain Items	2020
Fair value amortization	$ (21)
Legal, environmental and taxes other than income tax reserves	26
Change in fair value of derivative contracts[(a)]	(5)
Loss on divestitures and impairments, net[(b)]	327
Loss on impairment of goodwill[(c)]	1,600
Restricted stock accelerated vesting and severance	52
COVID-19 costs	15
Income tax Certain Items	(107)
Other	5
Total Certain Items	$ 1,892

a) Gains or losses reflected in Certain Items are unrealized. Gains or losses are reflected in our DCF when realized.
b) Includes a pre-tax non-cash impairment loss of $350 million related to oil and gas producing assets in our CO2 business segment driven by low oil prices and $55 million gain on an asset sale in our Terminals business segment.
c) Includes non-cash impairments of goodwill of $1,000 million and $600 million associated with our Natural Gas Pipelines Non-regulated and CO2 reporting units, respectively.

Reconciliations of KMI FCF & CO_2 Segment FCF

$ in millions

Reconciliation of KMI FCF	2016	2017	2018	2019	2020
CFFO (GAAP)	**$ 4,795**	**$ 4,601**	**$ 5,043**	**$ 4,748**	**$ 4,550**
Capital expenditures (GAAP)	(2,882)	(3,188)	(2,904)	(2,270)	(1,707)
FCF	**1,913**	**1,413**	**2,139**	**2,478**	**2,843**
Dividends paid[(a)]	(1,272)	(1,276)	(1,774)	(2,163)	(2,362)
FCF after dividends	**$ 641**	**$ 137**	**$ 365**	**$ 315**	**$ 481**

Reconciliation of CO_2 Segment FCF					
Segment EBDA	$ 827	$ 847	$ 759	$ 681	$ (292)
Certain items:					
Non-cash impairments and project write-offs	29	-	79	75	950
Derivatives and other	63	40	90	(49)	(6)
Severance tax refund	-	-	(21)	-	-
Adjusted Segment EBDA	**919**	**887**	**907**	**707**	**652**
Capital expenditures[(b)]	(276)	(436)	(397)	(349)	(186)
Acquisitions	-	-	(21)	-	-
CO_2 Segment FCF	**$ 643**	**$ 451**	**$ 489**	**$ 358**	**$ 466**

a) Includes dividends paid for the preferred shares for the years ended 2016, 2017, and 2018.
b) Includes sustaining and expansion capital expenditures.