2021 **INVESTOR DAY**

January 27, 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, opportunities related to alternative energy sources, future operating results or the ability to generate revenues, income or cash flow or to pay dividends 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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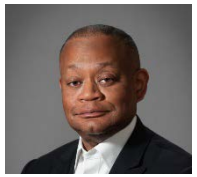
GAAP – Unless otherwise stated, all historical and estimated future financial and other information included in this presentation have been prepared in accordance with generally accepted accounting principles in the United States ("GAAP").

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.

Kinder Morgan 2021 Investor Day

Agenda & presenters

TIME	DISCUSSION	PRESENTER
8:00 – 8:20	Our Vision	 **Rich Kinder** *Executive Chairman*
8:20 – 9:00	Our Future	 **Steve Kean** *CEO*
9:00 – 9:40	Strategy & Business Review	 **Kim Dang** *President*
9:40 – 9:50	BREAK	
9:50 – 10:35	Panel with COO & Business Unit Presidents	 **James Holland** *COO*  **Tom Martin** *Natural Gas*  **Dax Sanders** *Products*  **John Schlosser** *Terminals*  **Jesse Arenivas** *CO_2*
10:35 – 11:00	2021 Budget	 **David Michels** *VP & CFO*
11:00 – 11:30	Q&A	

OUR **VISION**

Kinder Morgan Overview

KINDER MORGAN

LEADER IN U.S. ENERGY INFRASTRUCTURE

Energy infrastructure, especially natural gas pipelines & storage, has a decades-long time horizon

WHERE GOVERNANCE MATTERS

Managed for shareholders by shareholders

Delivering energy to improve lives & create a better world

Managed for shareholders by shareholders

Highly-aligned leadership with a long-term focus & disciplined stewardship of capital

13% ownership

by management & board

equity-based comp

a core part of executive compensation

68% of executive compensation is delivered in restricted stock

higher percentage than our proxy peer companies

discipline

low cost operator while maintaining safe & compliant operations

high return criteria on capital investments

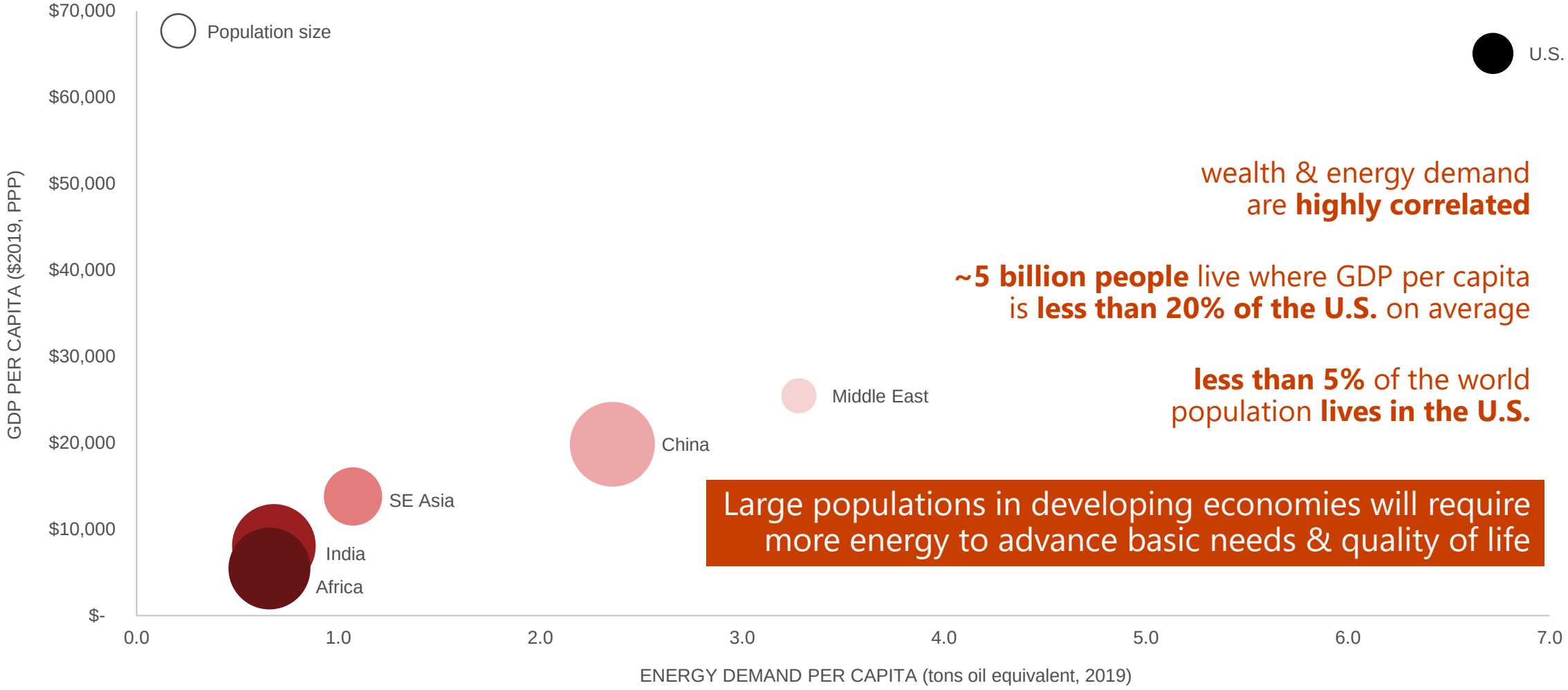
internally funding dividend & capex with cash flow

return excess cash to shareholders through well-covered dividend & opportunistic share repurchases

Note: Executives defined as Section 16 officers. Ownership based on outstanding equity & restricted stock units.

Quality of Life Differences Persist Around the World

Even by 2030, IEA estimates 660 million people remain without electricity & 2.4 billion rely on traditional biomass for cooking



wealth & energy demand are **highly correlated**

~5 billion people live where GDP per capita is **less than 20% of the U.S.** on average

less than 5% of the world population **lives in the U.S.**

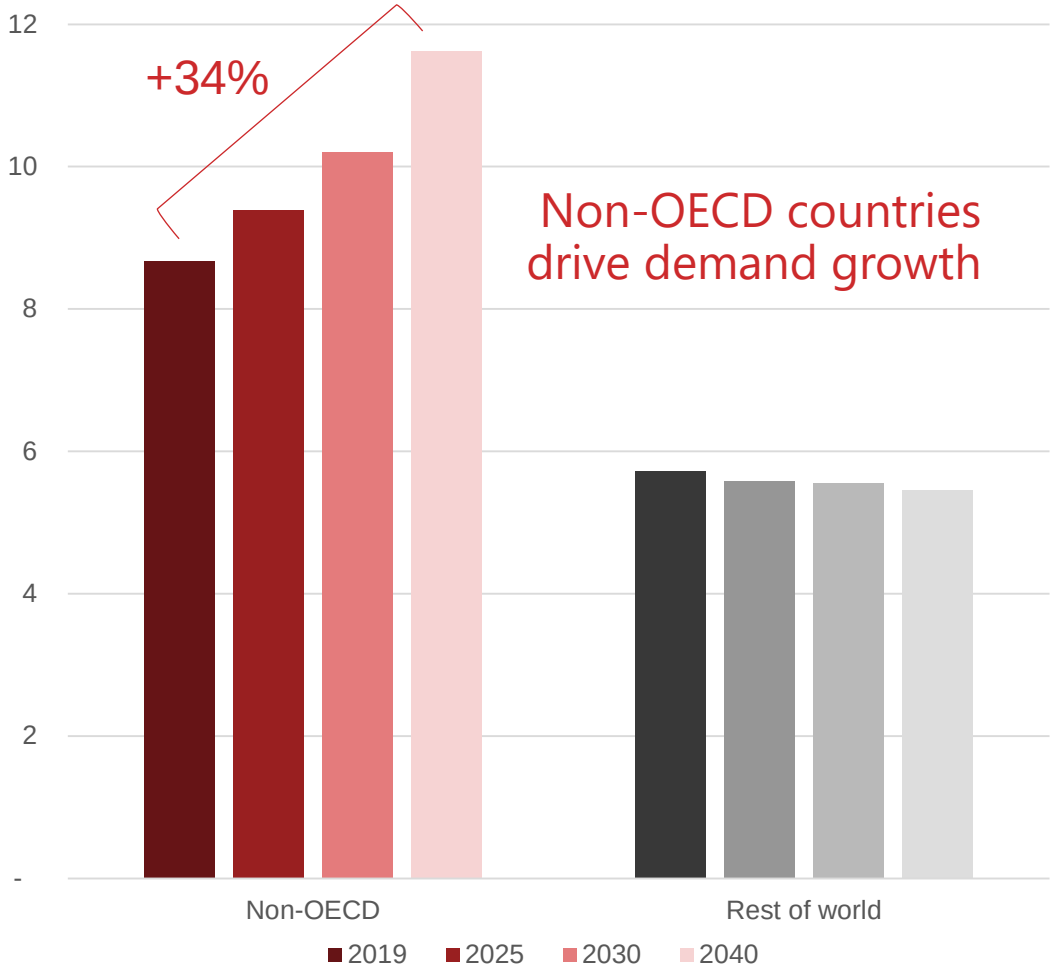
Large populations in developing economies will require more energy to advance basic needs & quality of life

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

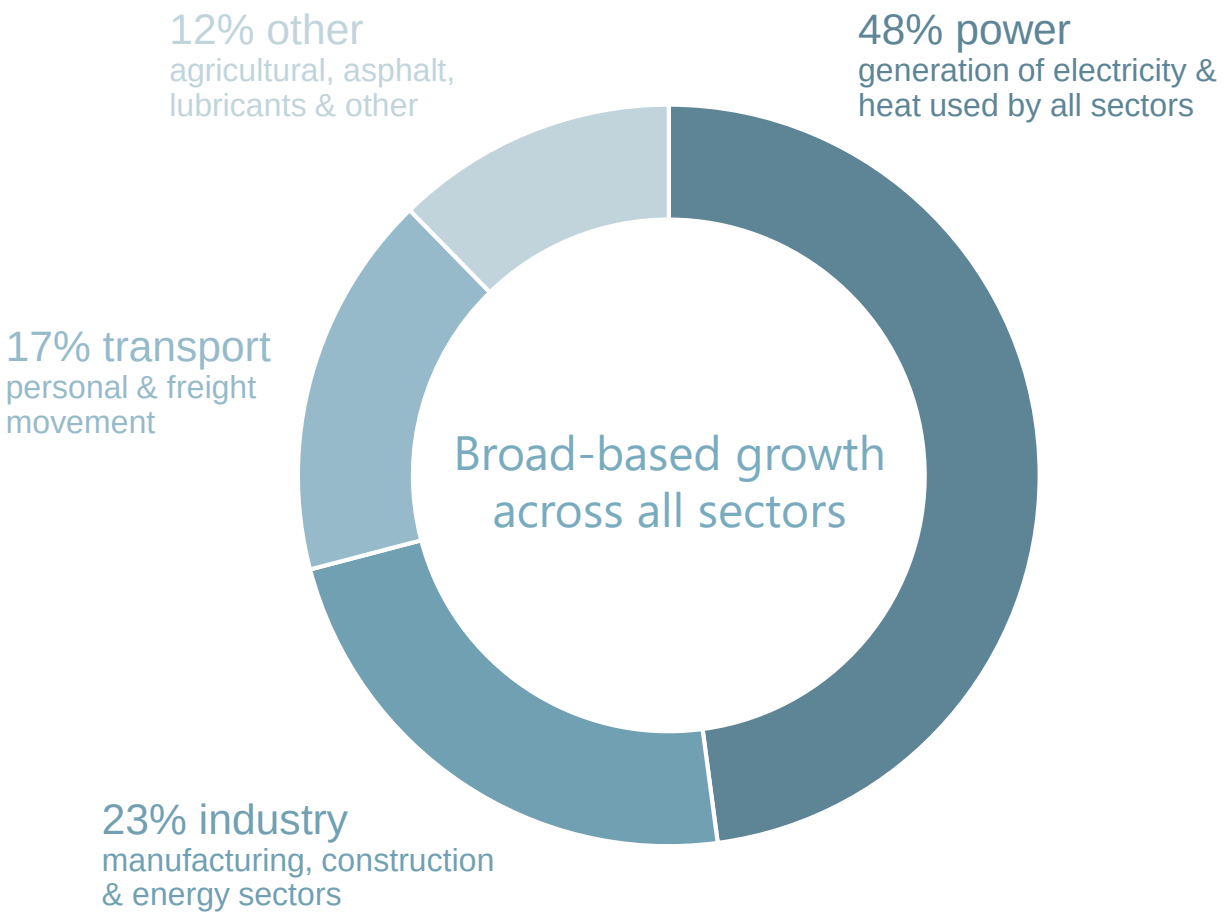
Asia & Africa Contribute Over 90% of Energy Demand Growth

Demand expected to be relatively stable in the rest of world as energy usage is central to everyday life

GLOBAL PRIMARY ENERGY DEMAND in billion tons oil equivalent



GROWTH BY SECTOR 2019 to 2040



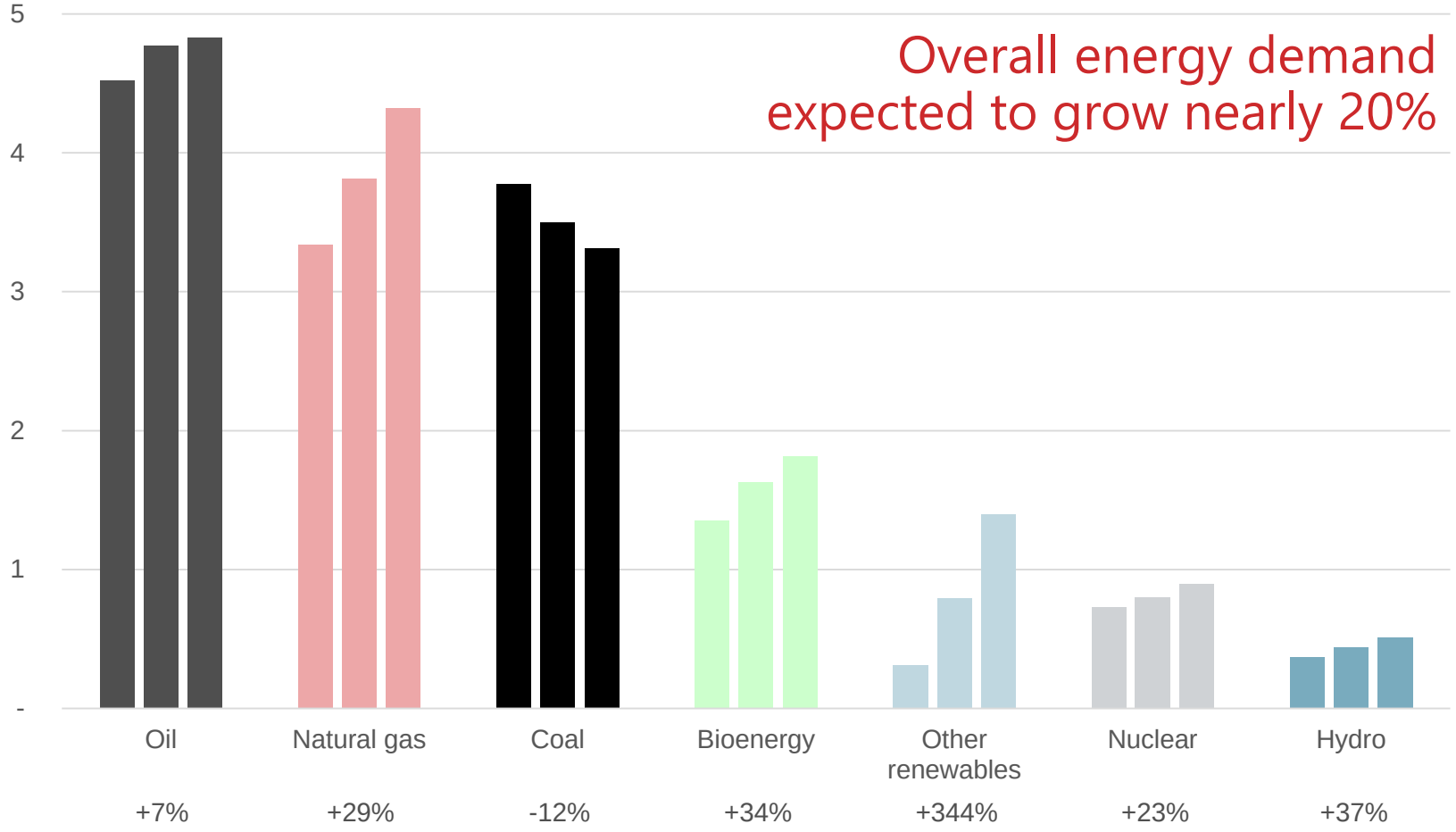
Source: International Energy Agency, World Energy Outlook, October 2020 (Total Primary Demand in Stated Policies Scenario).

All Available Sources Required to Meet Demand Outlook

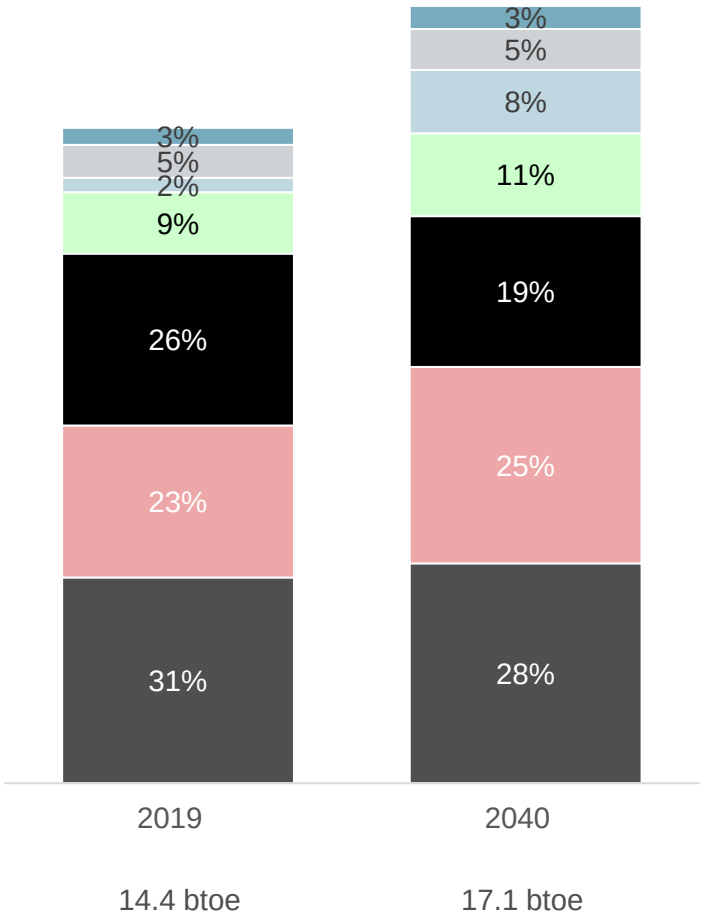
Even as the energy mix gradually shifts, hydrocarbons projected to remain essential to meeting demand

GLOBAL PRIMARY ENERGY DEMAND BY FUEL

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



total demand & % mix

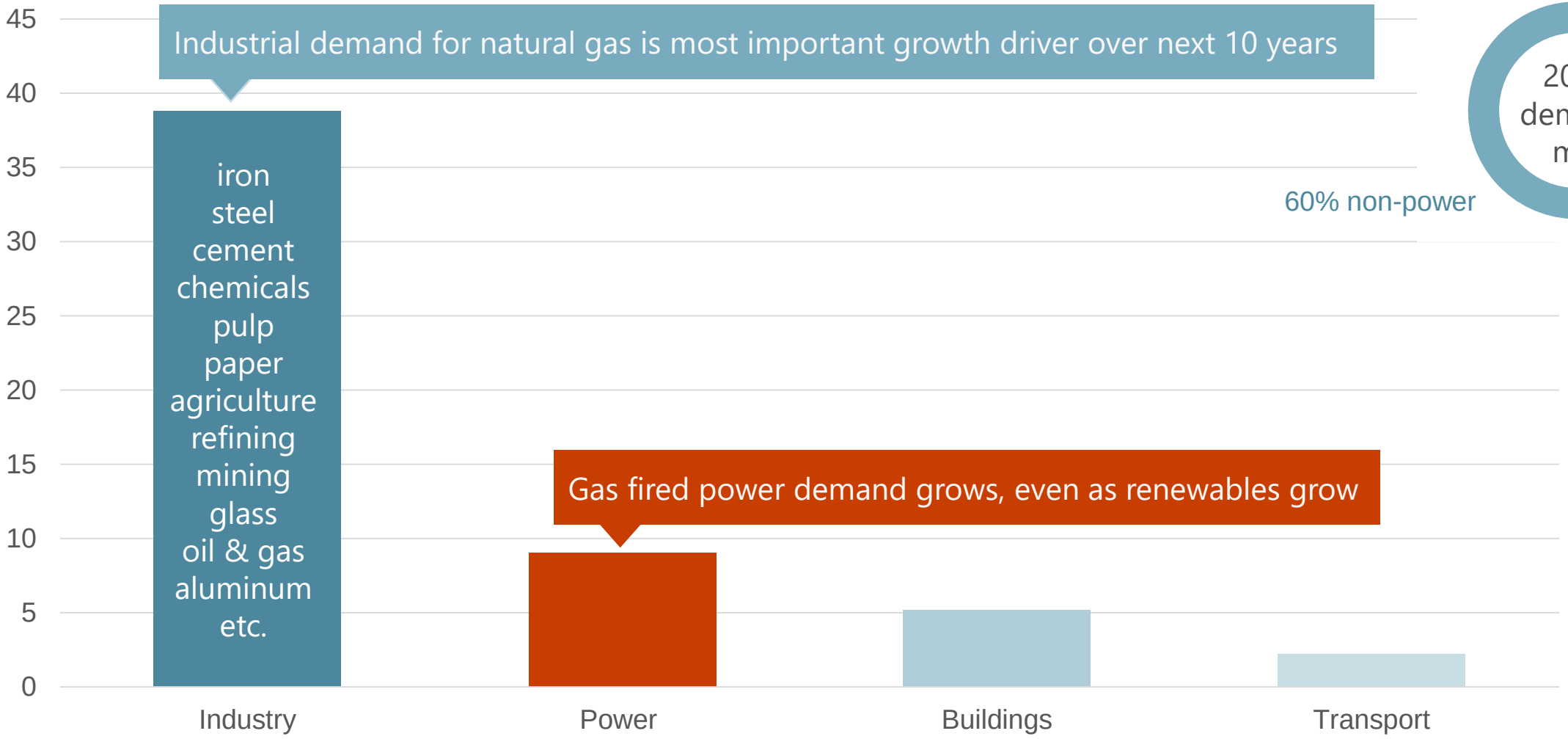


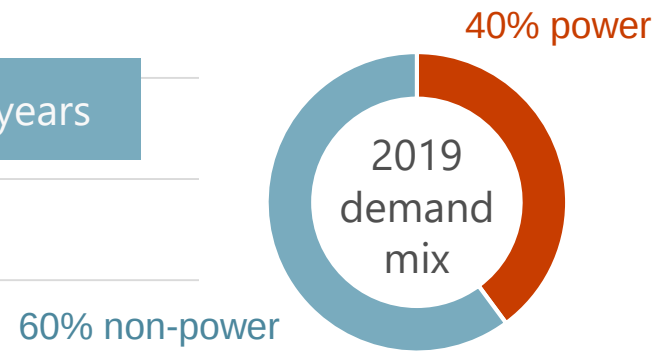
Source: International Energy Agency, World Energy Outlook, October 2020 (Total Primary Demand in Stated Policies Scenario).

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

Natural Gas Demand Enables Industrial Development

Global natural gas demand growth by sector from 2019 to 2030 (bcfd)



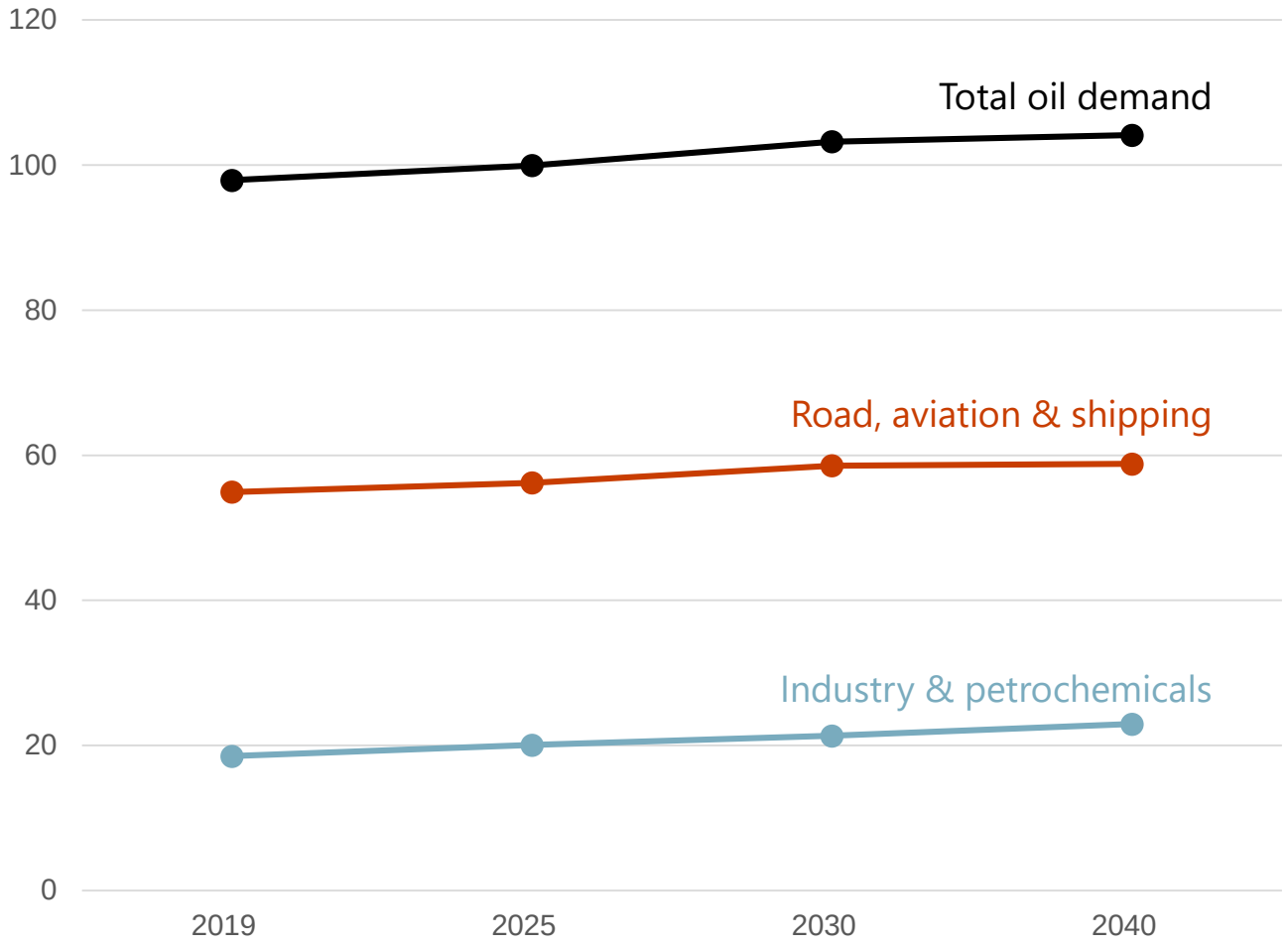


Source: International Energy Agency, World Energy Outlook, October 2020 (Stated Policies Scenario).

Growth in Global Oil Demand Expected through 2040

Efficiency efforts & EVs not enough to offset global increases in mobility & petrochemical demand

GLOBAL OIL DEMAND million barrels per day



Over the next decade:

+1.8 mmbbld from trucks

medium- & heavy-duty trucks play an increasing role in carrying goods & are harder to electrify

+1.2 mmbbld from aviation

primarily in emerging markets & developing economies & as biofuels blending share remains under 5%

+3.0 mmbbld for petrochemicals

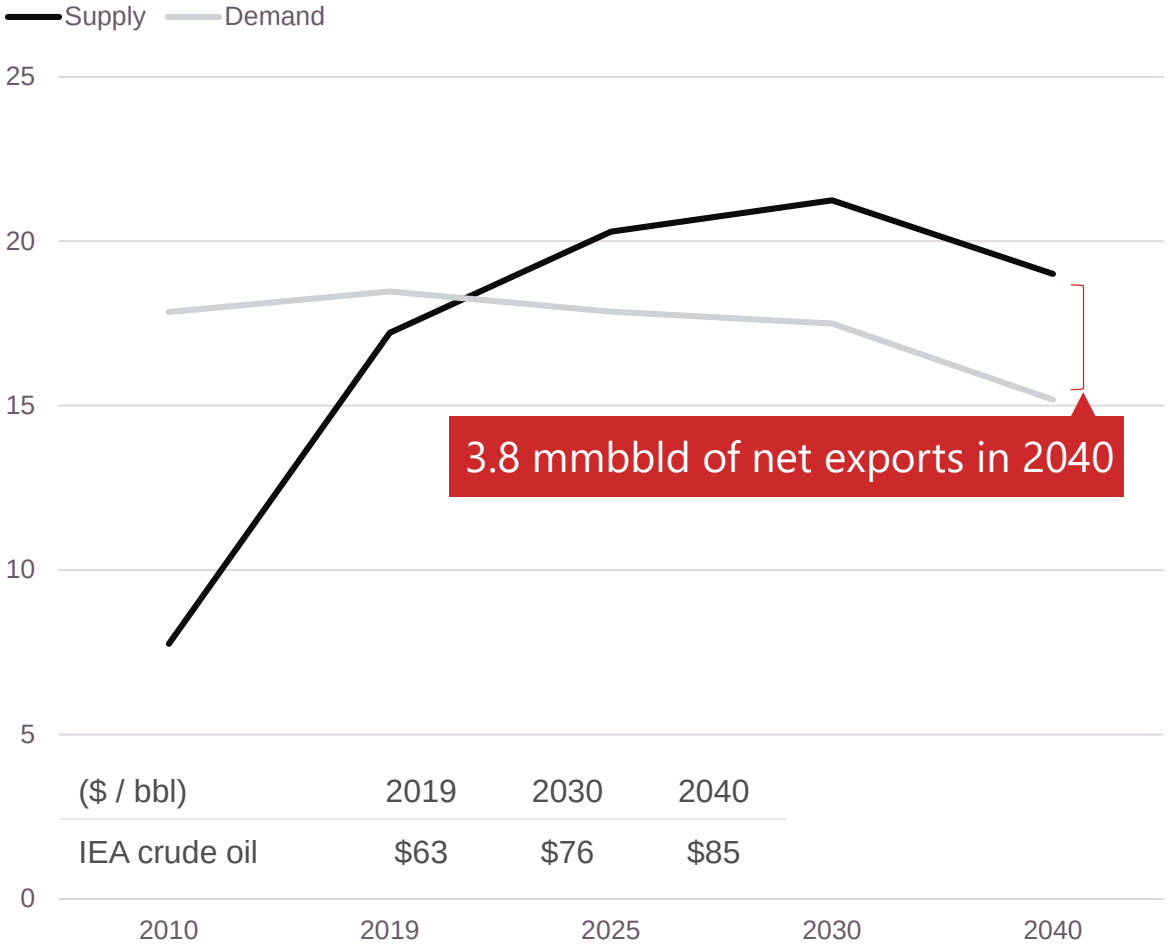
responsible for nearly 60% of oil demand growth

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

U.S. Helps Meet Increasing Global Demand

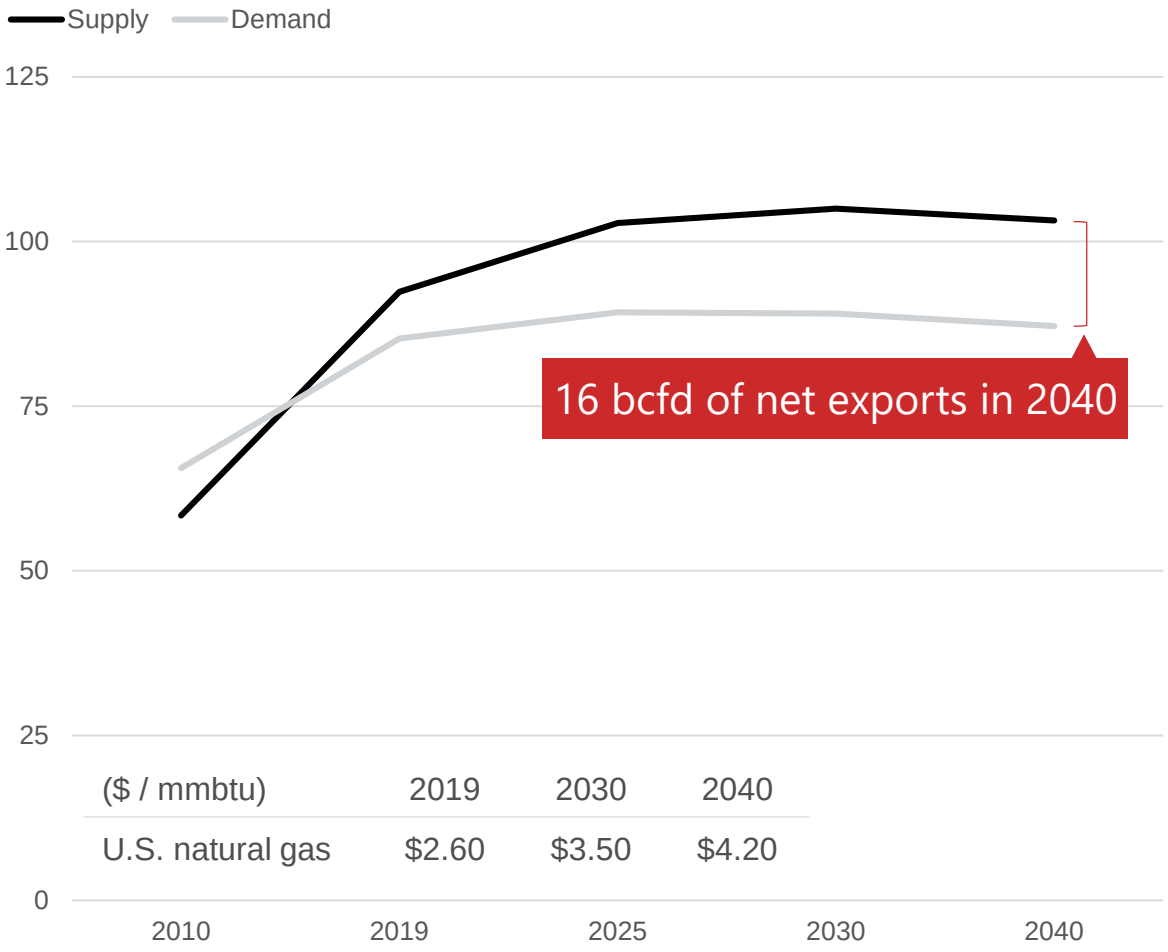
Reliable trade partner with competitive & more responsibly produced supply versus many global alternatives

U.S. OIL & LIQUIDS in million barrels per day



($ / bbl)	2019	2030	2040
IEA crude oil	$63	$76	$85

U.S. NATURAL GAS in billion cubic feet per day



($ / mmbtu)	2019	2030	2040
U.S. natural gas	$2.60	$3.50	$4.20

Source: International Energy Agency, World Energy Outlook, October 2020 (Stated Policies Scenario).
Note: Oil production includes lease condensate & natural gas liquids. Oil demand includes petroleum liquids. IEA crude oil price is a weighted average import price among IEA member countries & the U.S. natural gas price reflects the wholesale price prevailing on the domestic market.

KMI: a 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% current dividend yield	Top 10 dividend yield in S&P500 Expect to declare 3% dividend increase in 2021 vs. 2020
$2 billion share buyback program	Expect up to $450 million available for buybacks in 2021 while maintaining BBB balance sheet

OUR **FUTURE**

Doing Business the Right Way Every Day

For our shareholders, employees, customers & neighbors

vision

Delivering energy to improve lives & create a better world

mission

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

values

Integrity, accountability, safety & excellence

Affordable, reliable energy is essential to human development

Our Business is Resilient throughout an Energy Transition

KINDER MORGAN

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

Leader in North American Energy Infrastructure

Unparalleled & irreplaceable asset footprint built over decades

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

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

Largest natural gas transmission network

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

Largest independent transporter of refined products

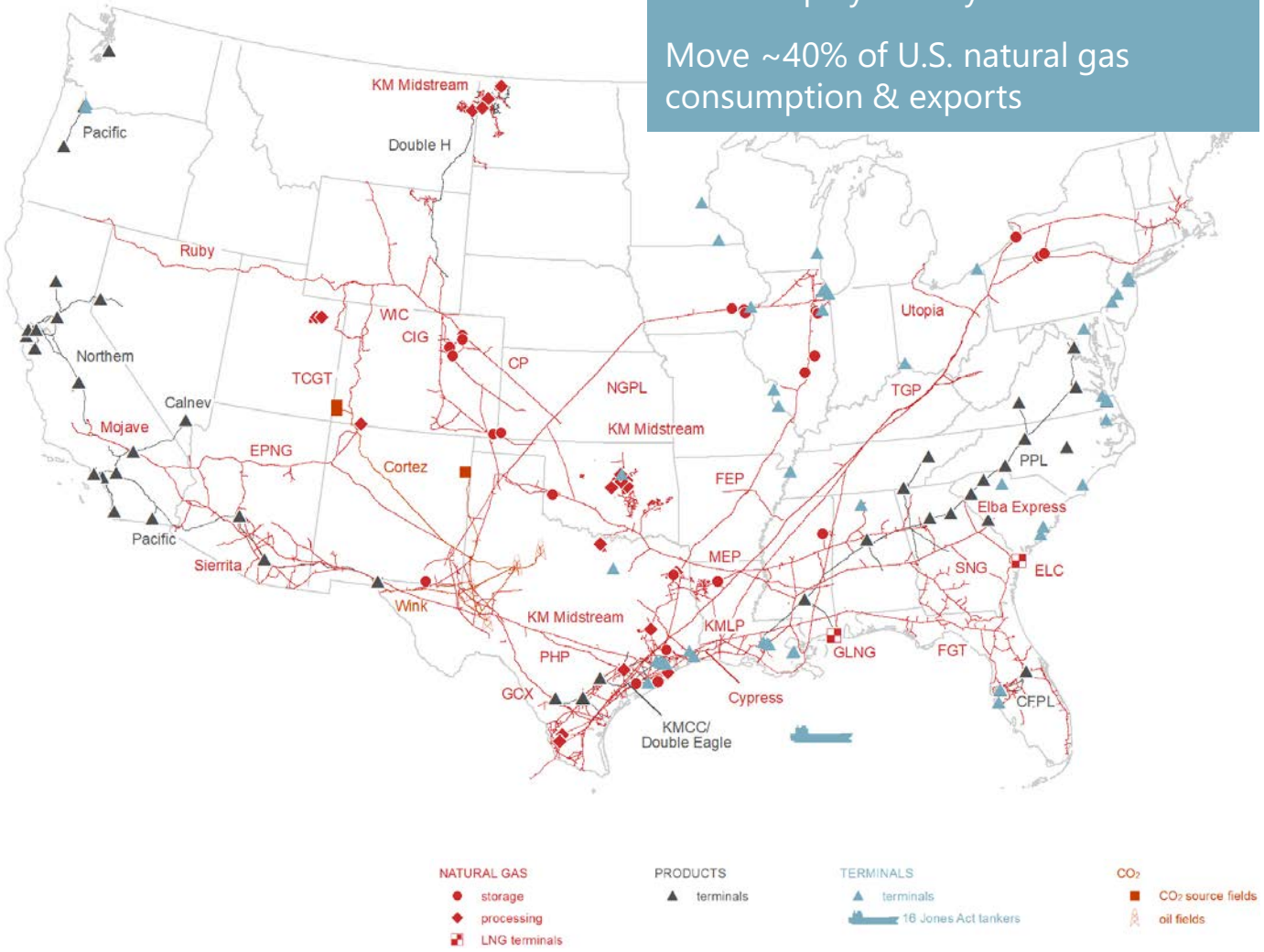
- Transport ~1.7 mmbbld of refined products
- ~6,800 miles of refined products pipelines
- ~3,100 miles of crude pipelines

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

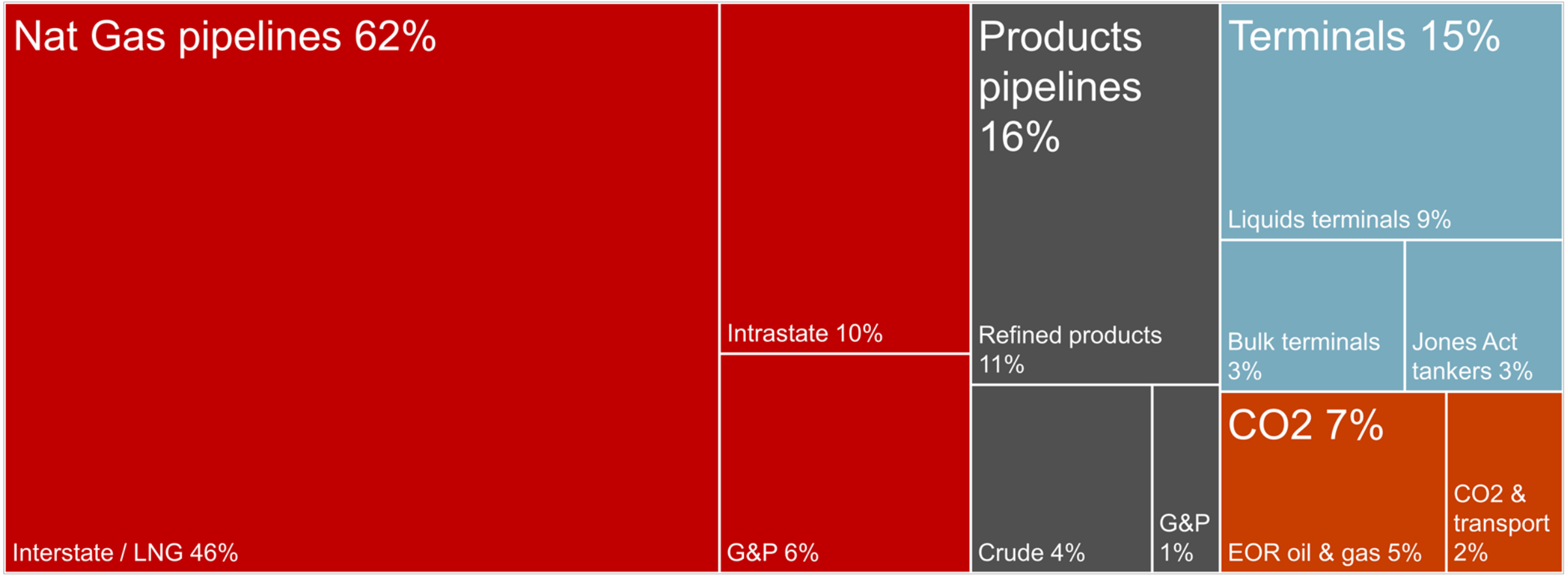


BUSINESS MIX

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

Business Mix

Leading infrastructure provider across multiple critical energy products



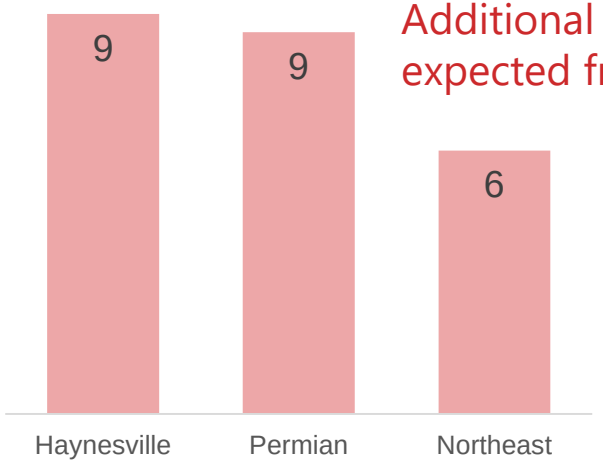
Note: Business mix based on 2021 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Substantial Growth Projected for U.S. Natural Gas

KINDER MORGAN

KEY BASINS DRIVING U.S. GROWTH

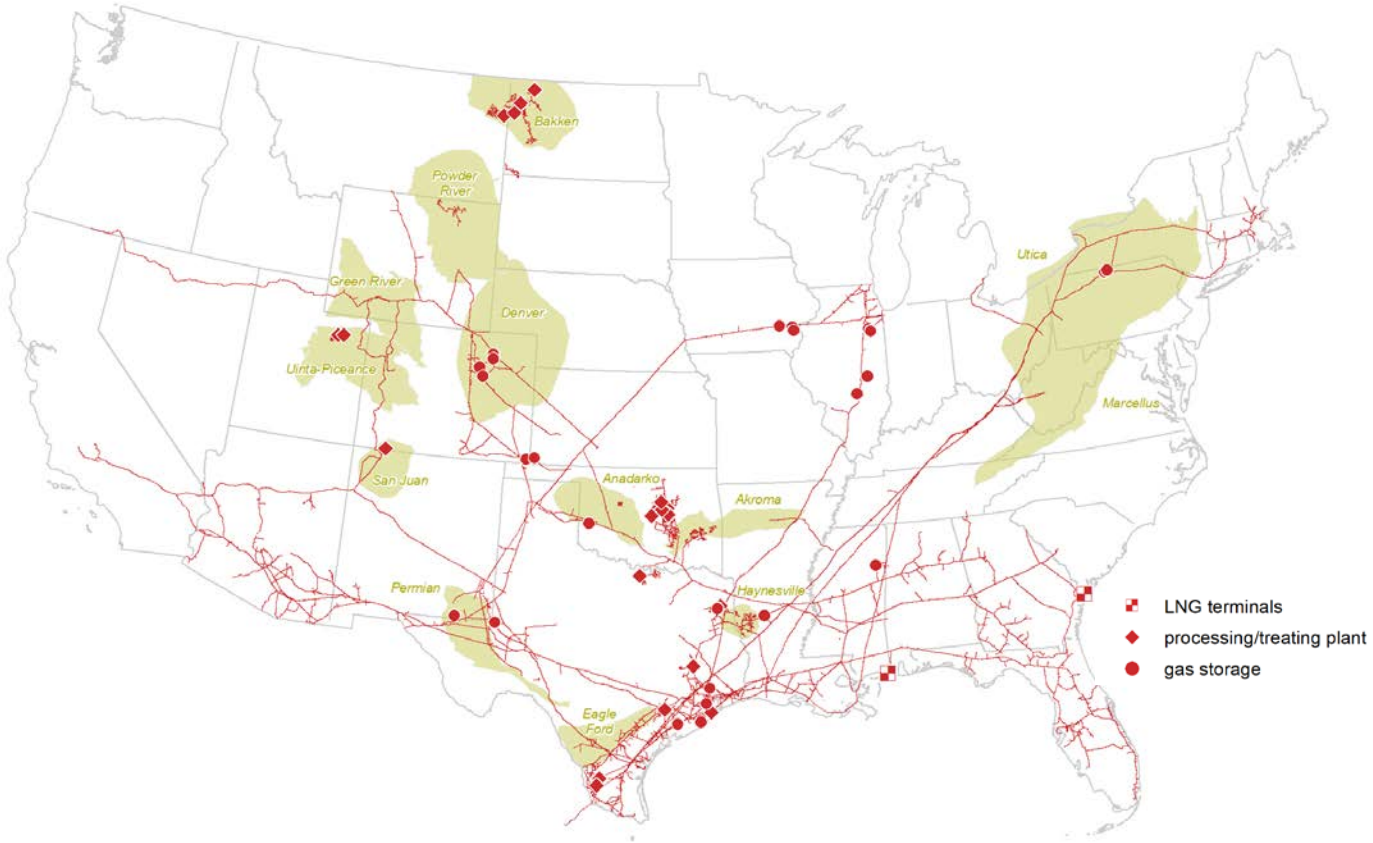
2020 to 2030 growth in bcfd



Additional 24 bcfd expected from three areas

DEMAND in bcfd

Exports & industrial driving majority of growth



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

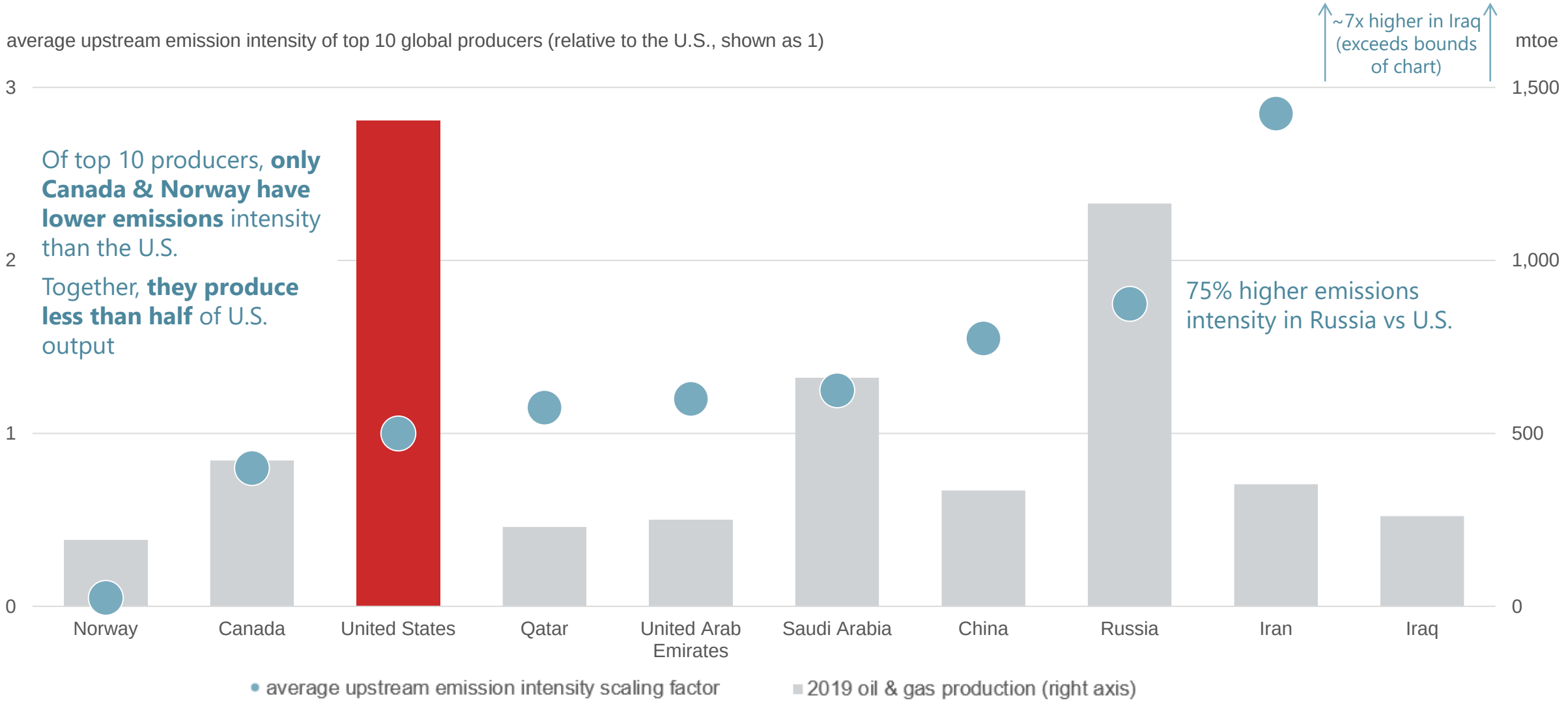
Our network connects key supply basins to multiple demand points along the Gulf Coast

Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, December 2020. Growth relative to projected 2020 production at the time of the report. Total U.S. natural gas production to grow by 18 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.

U.S. is a Responsible Producer of Critical Energy Products

One of the lowest emissions intensity producers in the world & at unmatched scale

average upstream emission intensity of top 10 global producers (relative to the U.S., shown as 1)

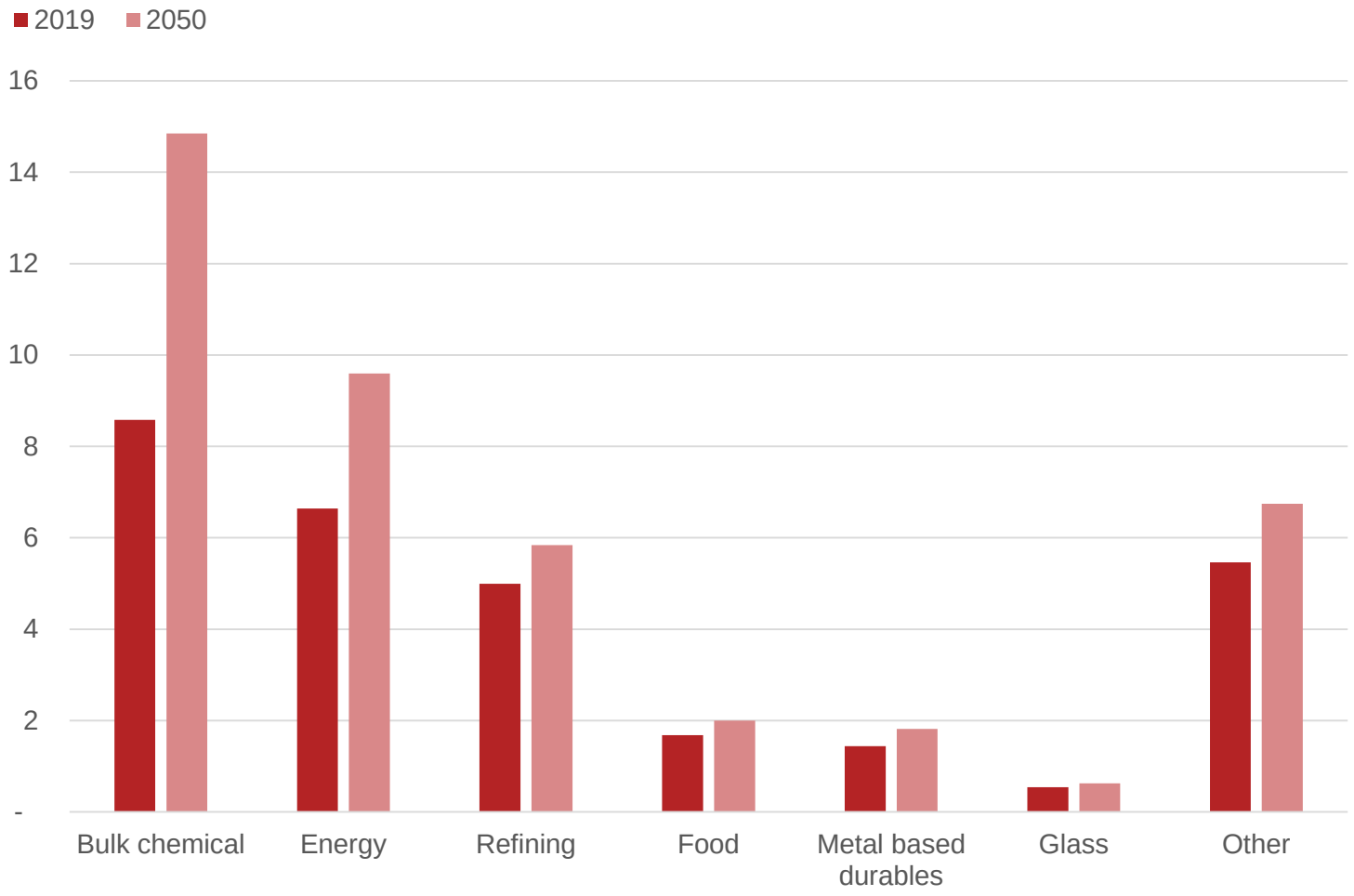


Source: International Energy Agency, World Energy Outlook, October 2020, World Energy Model assumptions.
Note: Scaling factors are based on the age of infrastructure and types of operators within each country (international, independent, or national oil companies). The strength of regulation and oversight, incorporating government effectiveness, regulatory quality and the rule of law as given by the Worldwide Governance Indicators compiled by the World Bank (2017), affects the scaling of all intensities.

Growing U.S. Industrial Demand for Natural Gas

Primarily used for process heat

U.S. NATURAL GAS INDUSTRIAL DEMAND BY SECTOR in bcfd



Bulk chemicals sector drives U.S. industrial demand for natural gas

Use for heat & power to nearly double by 2050

Also used as feedstock for ammonia (primarily to create fertilizer) & methanol

Natural gas is the primary fuel source for many industries

Difficult to replace in these industries given the extremely high temperatures required in the manufacturing processes

Difficult to replace in the food industry as well given cooking needs

Natural gas is also an important fuel source in several other industries

Iron & steel, paper, agriculture, plastics, aluminum, wood products, cement & construction

Source: U.S. EIA 2020 Annual Energy Outlook (1/29/2020).
Note: Bulk chemicals are chemicals used as raw materials in the manufacture of other products, mainly fine chemicals which are then sold directly to users.

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

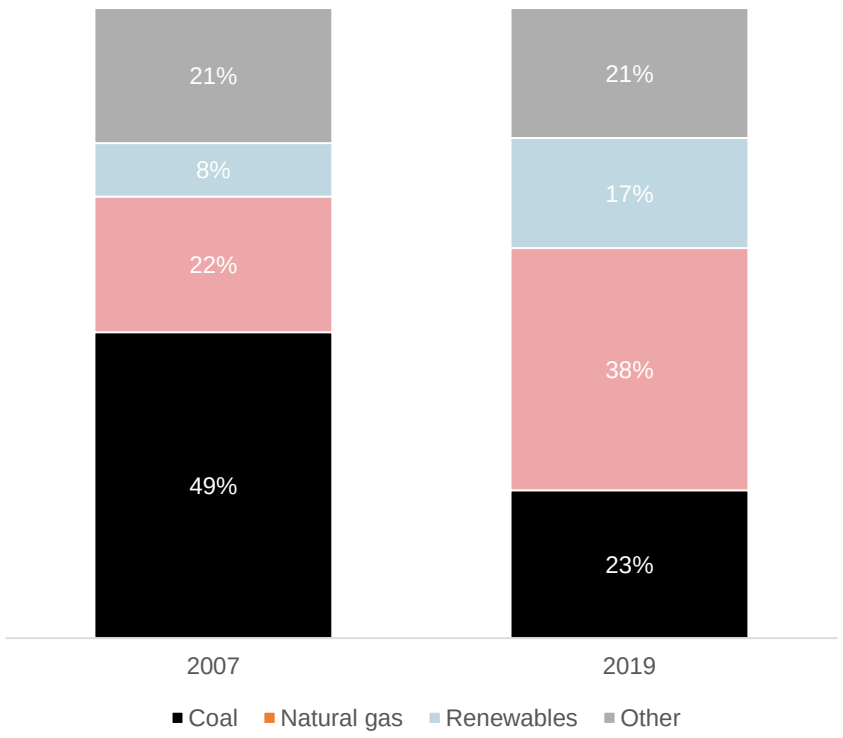
Our irreplaceable assets are essential to moving the fuels of today & tomorrow

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

Primarily due to converting coal power generation to natural gas generation

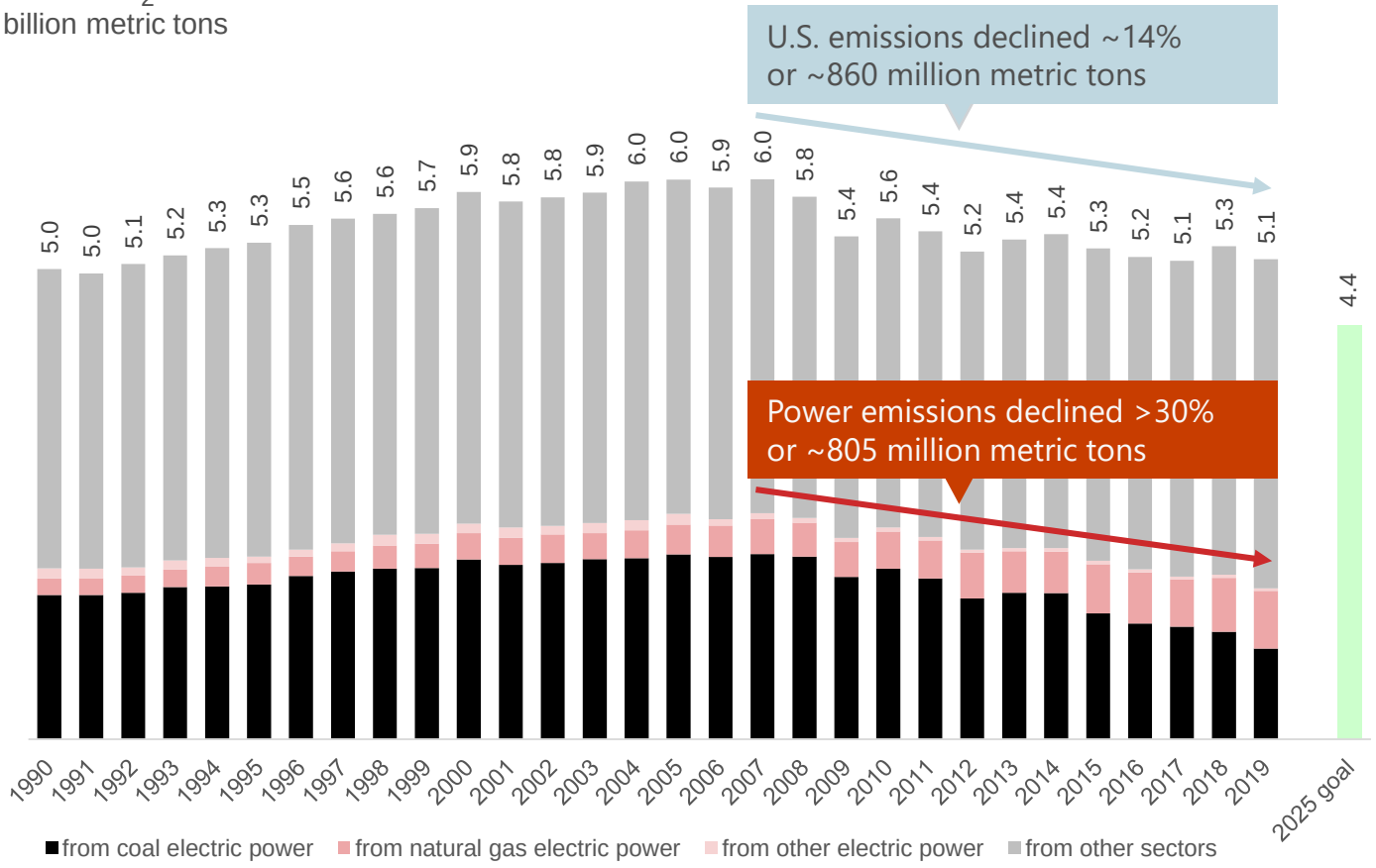
U.S. ELECTRICITY GENERATION MIX

% of total generation



U.S. CO_2 EMISSIONS

billion metric tons



Under the 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).

Replacing Coal Power Could Accelerate Emissions Reductions Goals

Power sector contributes ~40% of energy-related CO_2 emissions globally

Natural gas is **more efficient**

Burning natural gas is 25% more efficient than coal on average

& **lower carbon** than coal

Coal releases ~75% to 85% more CO_2 per Btu than natural gas

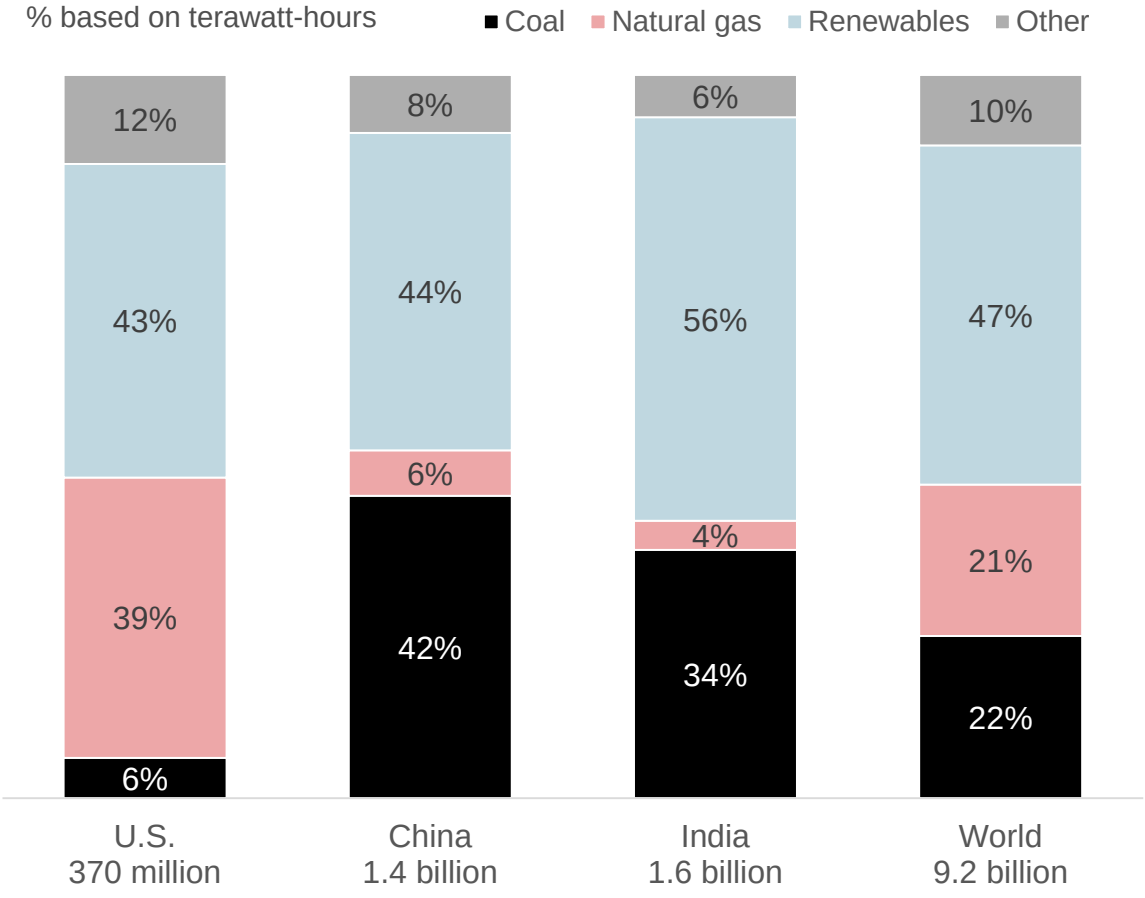
resulting in **60% lower** emissions

from natural gas fired generation versus coal-fired plants

China & India to use coal to firm renewables
Not ideal for meeting emissions reduction goals
U.S. can't solve it alone as 4% of global population

POWER GENERATION MIX & POPULATION IN 2040

% based on terawatt-hours

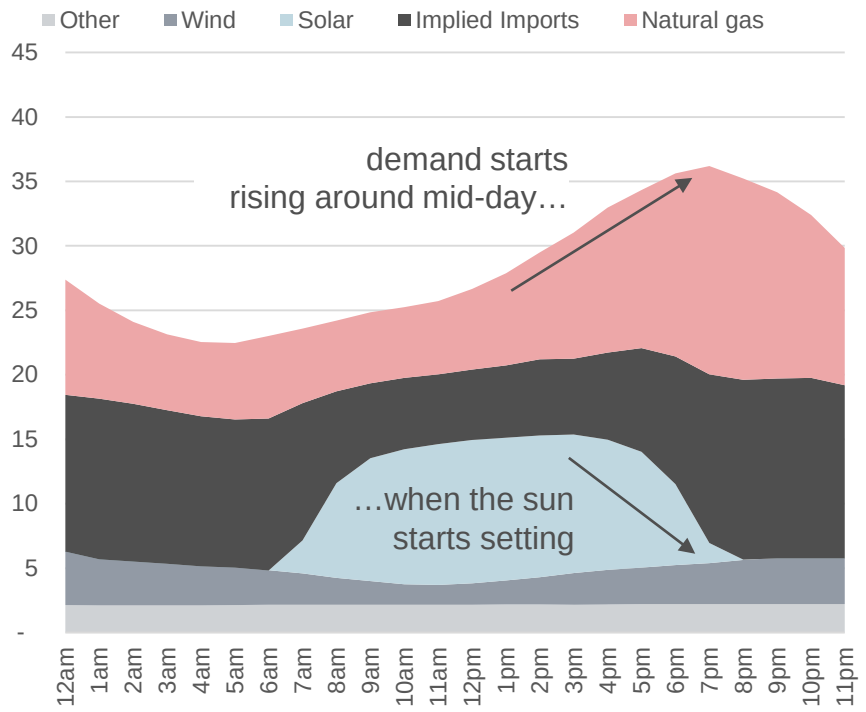


Source: U.S. Energy Information Agency, U.S. National Energy Technology Laboratory, International Energy Agency, World Energy Outlook, October 2020 (Stated Policies Scenario).
Note: Efficiency statistic based on heat rate (million Btu per kWh). Other in electric power generation mix includes nuclear & oil.

Natural Gas Steps In when Renewables Drop Out

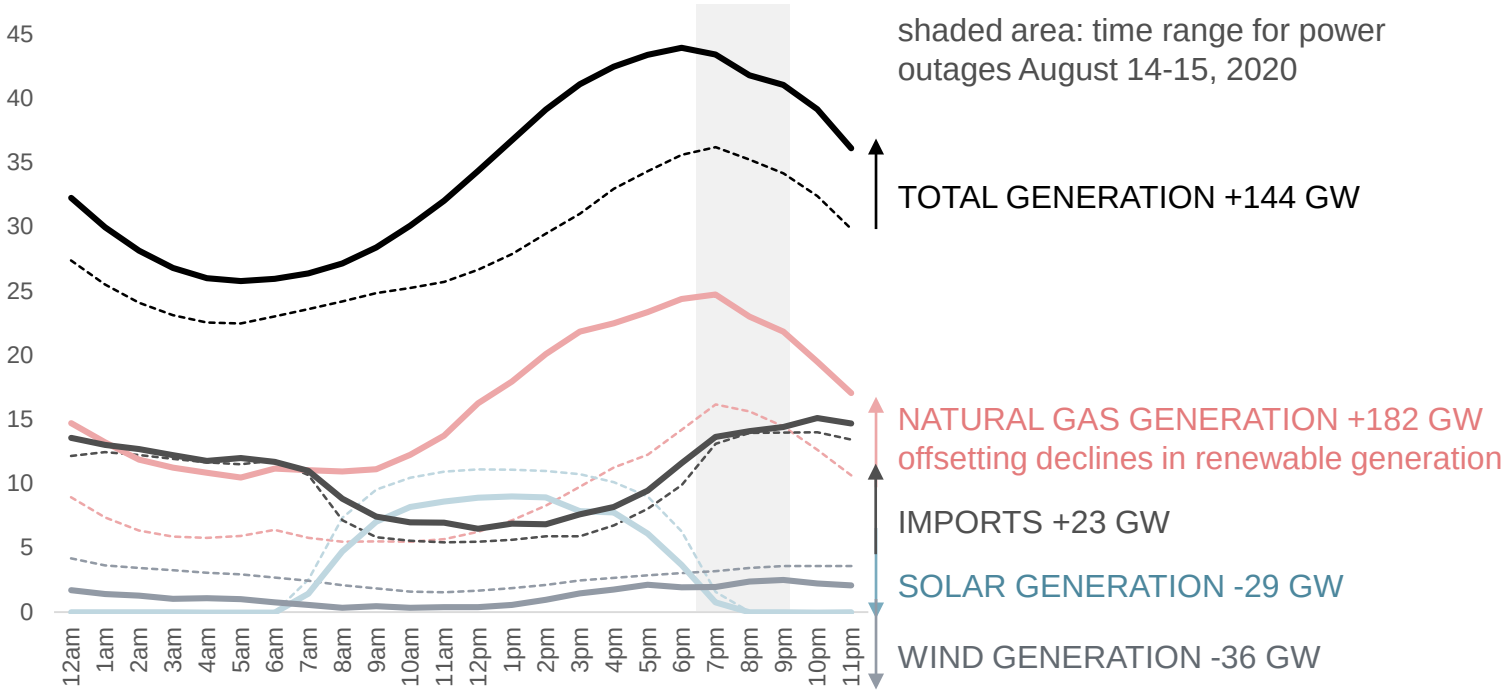
Renewable generation can be inadequate at inopportune times – during highest demand points in day or even full week

AVERAGE CALIFORNIA DAY during August 1-12, 2020
gigawatts (GW)



By peak demand hour around 7pm, solar generation is almost non-existent

SOLID LINES: AVERAGE DAY DURING CA HEAT WAVE August 13-16, 2020
DASHED LINES: AVERAGE DAY FOR TYPICAL CA WEATHER August 1-12, 2020
gigawatts



Power demand increased during heat wave, but renewable generation declined

Natural gas generation increased significantly in order to make up for the renewable shortfall

Still, customers were left without power: almost 500,000 on Aug 14 & >300,000 on Aug 15

Adequate natural gas generation capacity could have prevented the need to curtail power

Source: U.S. EIA Hourly Electric Grid Monitor. "Other" includes generation from coal, petroleum, hydro & nuclear.

Renewable Growth Requires Operational Flexibility

Proper coordination between grid & pipeline operators required to make sure power demand is met

baseload generation

- delivered consistently & uniformly throughout the day
- typically includes various amounts of coal, hydro, nuclear & natural gas-fired combined cycle generation
- cannot fluctuate up & down quickly enough to meet variable demand or firm intermittent renewables

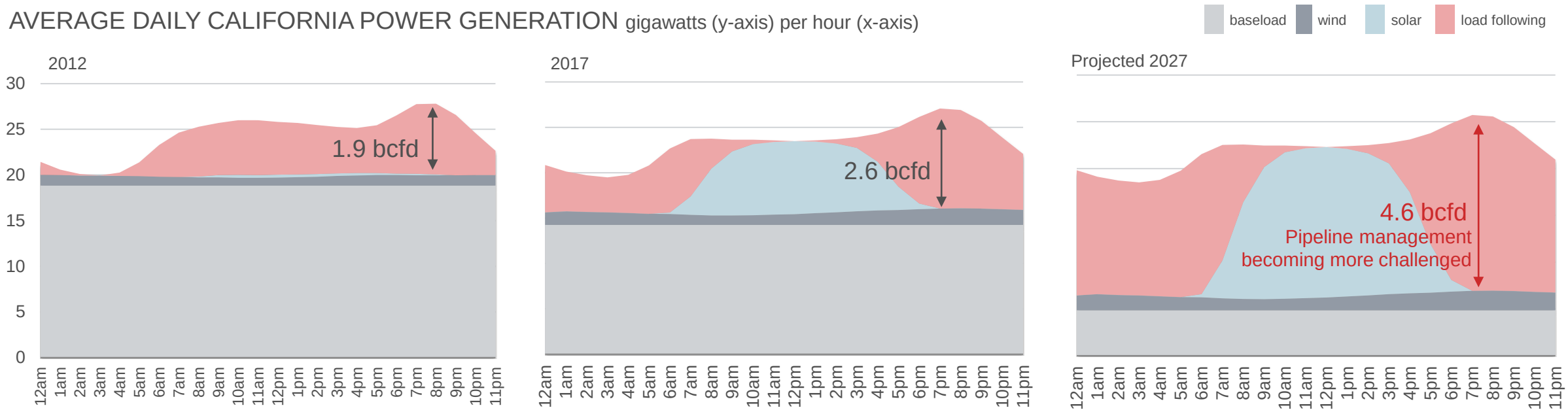
solar generation

- because the sun is not always shining, solar generation has to be backstopped by dispatchable power
- backstop needs to be variable / quick-starting due to steep solar ramping (up & down) in am & pm

load following generation

- quick-starting generation that can immediately respond to variable changes in demand
- useful in firming intermittent renewable generation
- generally natural gas-fired peaking generation

AVERAGE DAILY CALIFORNIA POWER GENERATION gigawatts (y-axis) per hour (x-axis)



As renewable capacity increases & baseload capacity is retired, the generation mix shifts from uniform to variable
Pipeline operators have to manage the increased variability on their pipelines as well

Source: CAISO, KM analysis.
Note: Load following in this example is natural gas-fired generation. Graphs are based on month of March.

Enhanced Natural Gas Deliverability Optimizes Flexible Grids

With proper coordination, gas-fired generation can be dispatched optimally to meet multiple important objectives

Key components to supporting an electric grid with increasing levels of wind & solar:

HOURLY & NO NOTICE PIPELINE SERVICES

ADEQUATE PIPELINE CAPACITY

SUFFICIENT & RESPONSIVE STORAGE

Meet demand at lower cost & lower emissions while maintaining reliability

Natural Gas Infrastructure Offers A Ready-Made Storage Solution

Underground storage functions as a large capacity, highly effective battery today

PROVIDING A BETTER BATTERY:

Incredibly large capacity
(enough for days, weeks & months)

Reliably dispatchable
(over short & long durations)

Uses existing infrastructure

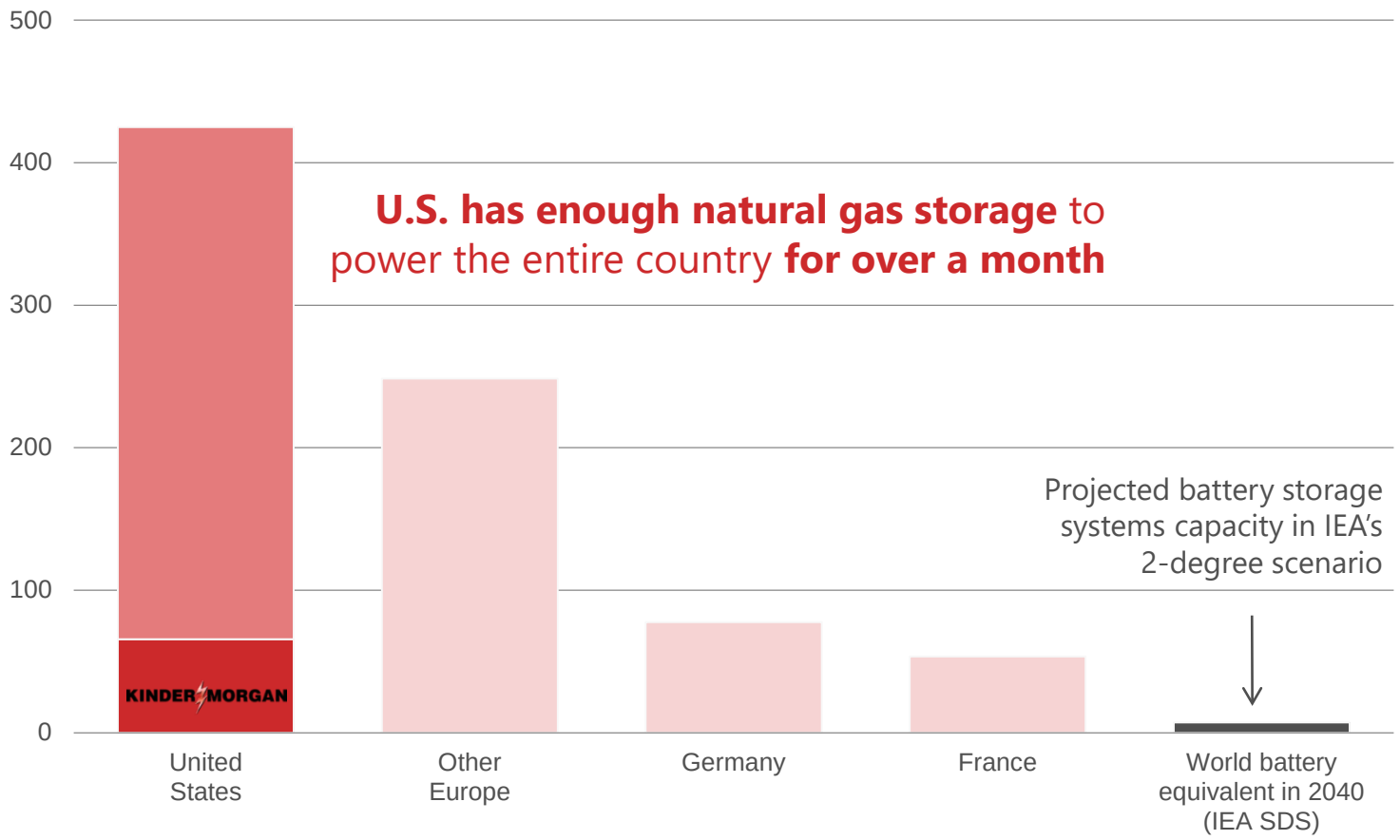
Competitively priced

Enhanced by pipeline management

Does not require technological advancement

Enabling customers across our network to deploy renewables today

UNDERGROUND STORAGE terawatt hours of power

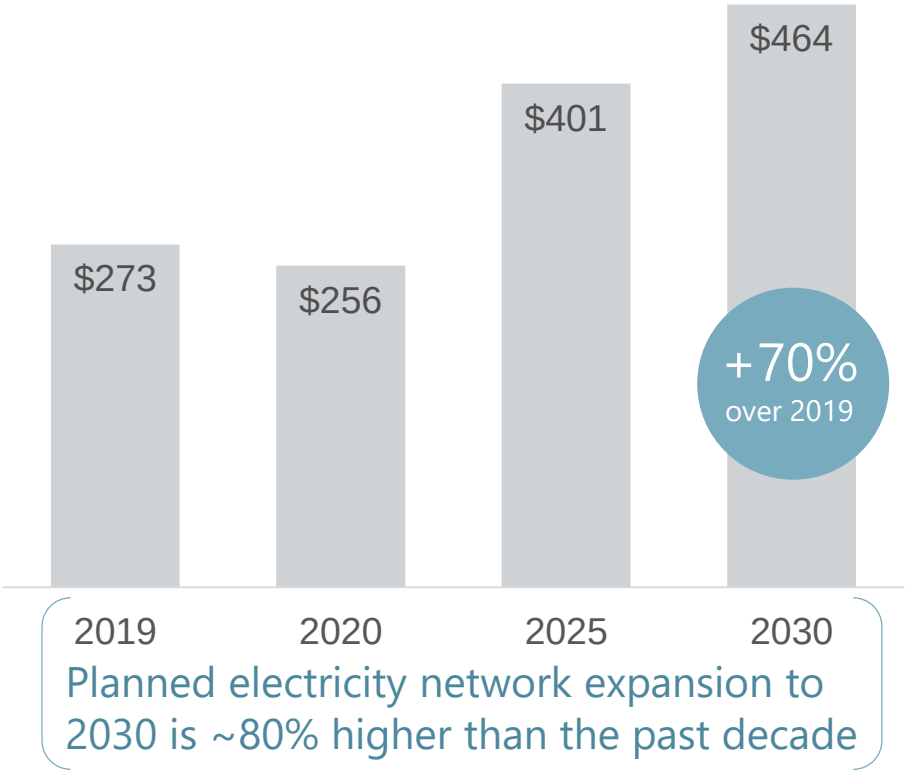


Source: KM analysis, IEA World Energy Outlook, October 2020.
Note: Natural gas energy converted terawatt hours (TWh) at 0.29 TWh per 1 MMDth; then, energy storage converted into power equivalent using assumed 34% efficiency rate of a natural gas peaker plant.

Infrastructure Planning Considerations

Multi-faceted analysis needed to balance cost, readiness & environmental impact

GLOBAL ANNUAL POWER GRID INVESTMENT
$ billions



COST	Studies indicate that electricity supply cost is manageable up to ~50-60% renewable penetration today	Increasing from 60% to 80% & 100% results in a 7x & 24x cost increase due to the significant amount of battery storage required to meet peaks
ENVIRO IMPACT	75-90% of solar & wind emissions are from the manufacturing & disposal of the equipment (Scope 2 & 3)	Important to look beyond Scope 1 when shaping policies like carbon tax, which create incentive mechanisms across the full supply chain
	Solar farms, hydro dams & wind farms all require **at least 10x** as many total tons (mined, moved & converted into machines) to deliver the same quantity of energy as a natural gas power plant	Local production capabilities & costs factor into energy decisions, particularly in emerging economies
READINESS	"Lower-income countries need industrial development to create jobs,	& gas is an ideal industrial fuel. Industries like petrochemicals can be anchor customers for financing gas infrastructure." *Stanford Program on Energy & Sustainable Development*

"Our analysis underlines the importance of adequate infrastructure planning (including the linkages with plans for gas networks)..." - *IEA*

Source: IEA World Energy Outlook, October 2020 (Stated Policies Scenario); National Renewable Energy Laboratory; U.S. Energy Information Administration. Clean Air Task Force Feb 2019 analysis of CAISO data. Department of Energy 2015 Quadrennial Report Table 10.4.

Well-Positioned to Move Potential Fuels of the Future

RNG & hydrogen can utilize much of the existing natural gas infrastructure network

RNG is a pipeline-quality gas that is **interchangeable with conventional natural gas**

Can be transported, stored & used in the same applications as natural gas

Hydrogen could be shipped on natural gas pipelines in 5% to 10% blends with **little to no modification**

Depends on pipeline metallurgy, age & other operating parameters

5-10%

Hydrogen is **energy dense** & well suited to **long-distance transportation**

Volumetrically, hydrogen is 1/3 as energy dense as natural gas

May require ~3x the capacity to transport equivalent amounts of energy

~3x infrastructure capacity

Pipelines can transport hydrogen **more efficiently** than transmission lines[a]

Larger quantities

10-20x cheaper

Avoids the electricity losses

"Existing gas infrastructure is a valuable asset with significant storage capacity that can be repurposed over time to deliver large volumes of biomethane or, with modifications, low-carbon hydrogen" - IEA

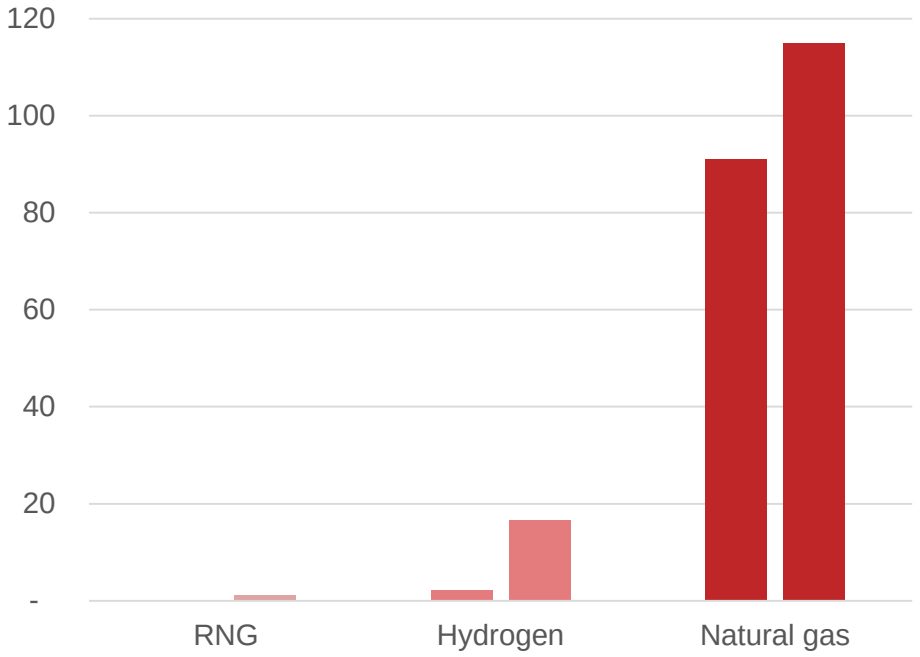
a) Source: Becker, Meike. "All hydrogen roads lead to renewables (and through Rome?)" Sanford C. Bernstein & Co., LLC. September 3, 2020.

Opportunity for Natural Gas Infrastructure

Renewable alternatives are small in scale today, but could grow to meet nearly 20% of current U.S. demand as costs decline

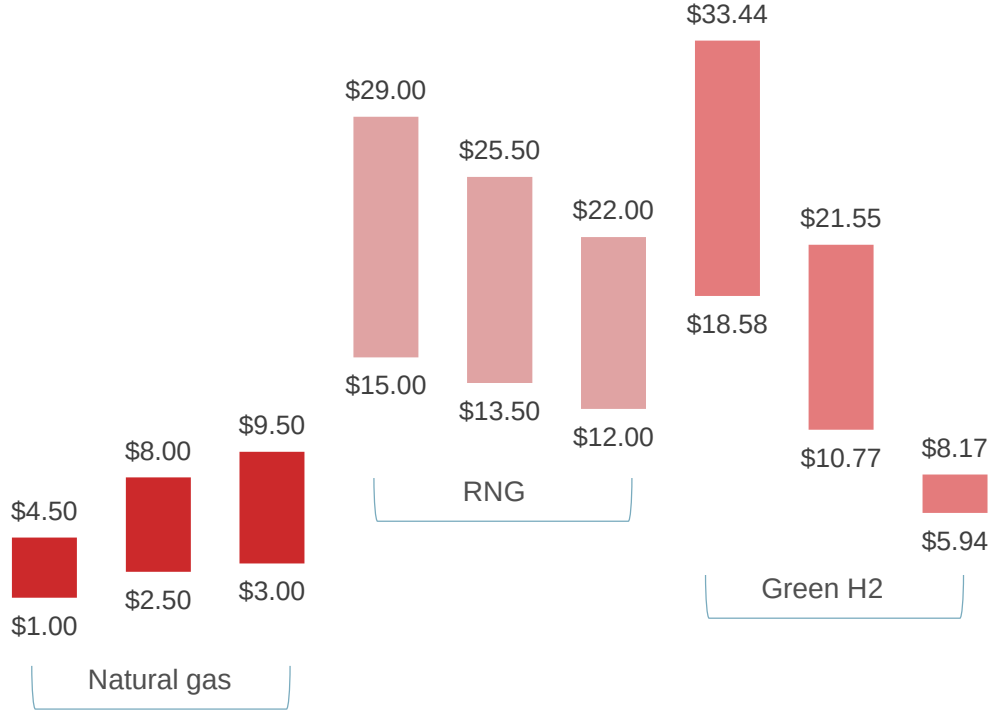
U.S. SUPPLY

bcfd, 2020 & 2050 potential



COST ESTIMATES

$ per Dth | 2020, 2030, & 2050



Similar to the way natural gas is used today:

Both can be transported as a gas by pipelines, moved in liquid form by ships & stored in geologic caverns & depleted reservoirs

Could help decarbonize many sectors & applications: fuel for power & transport, heat for industry & buildings, feedstock for chemicals, etc.

Source: 2020 U.S. RNG supply estimated from EPA. 2050 U.S. RNG supply potential from NREL. "Energy Analysis - Biogas Potential in the United States." October 2013.
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.
Cost estimates from IEA & KM analysis. Current U.S. natural gas demand based on 2020 estimate of 96 bcfd (including exports) from WoodMackenzie Fall 2020 Long Term Outlook.

Responsibly Sourced Natural Gas

Conventional natural gas produced by companies whose operations have been independently verified as meeting certain ESG standards

Standards typically focus on management practices for

METHANE EMISSIONS | **WATER USAGE** | **COMMUNITY RELATIONS**

10 ONE Future members have committed to responsibly produce natural gas & targeted a methane emission intensity rate of **0.28%** of production by 2025

The 10 member companies produced ~11 bcfd of responsibly produced natural gas in 2019 **~11%** of current U.S. natural gas production

Given consumers' growing climate-related concerns, the market for responsibly sourced natural gas is expected to grow as consumers demand that their natural gas be responsibly produced & transported

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

Carbon Capture Utilization & Storage (CCUS)

Positioned to leverage our existing expertise & capabilities to provide CCUS services in the future

Our experience & current operations cover the CCUS value chain

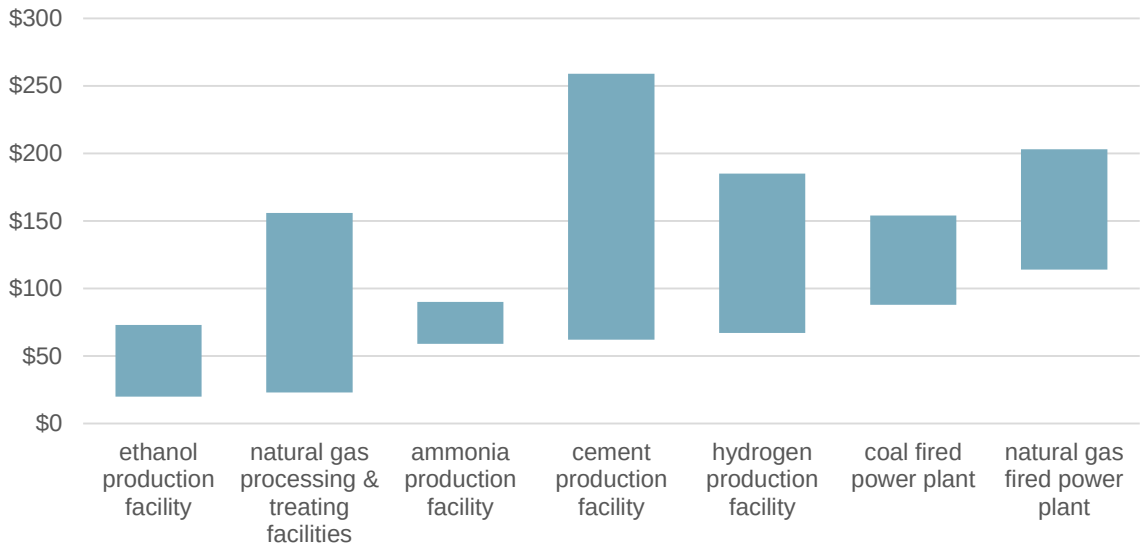
- Design, manufacture, install & operate equipment needed for CO_2 separation
- Operate >1,300 miles of CO_2 pipeline — more than any company in the U.S. with total system capacity of >3 bcfd
- Secure geologic storage of CO_2 via CO_2 enhanced oil recovery (EOR)

Participate with other organizations to advance CCUS policy & technology

Future opportunity to participate in CCUS

- Transportation of very large volumes of CO_2 will be required in order to meet CCUS goals
- Converting other types of pipelines to long haul CO_2 is rarely feasible
- Manufacture & installation of primarily new capture equipment necessary for 45Q eligibility
- EOR is widely viewed to be the best disposition for captured CO_2, but the best EOR potential is distant from most major sources of CO_2

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



Given 45Q credits, CCUS is economic for some ethanol production, natural gas processing, and natural gas treating facilities

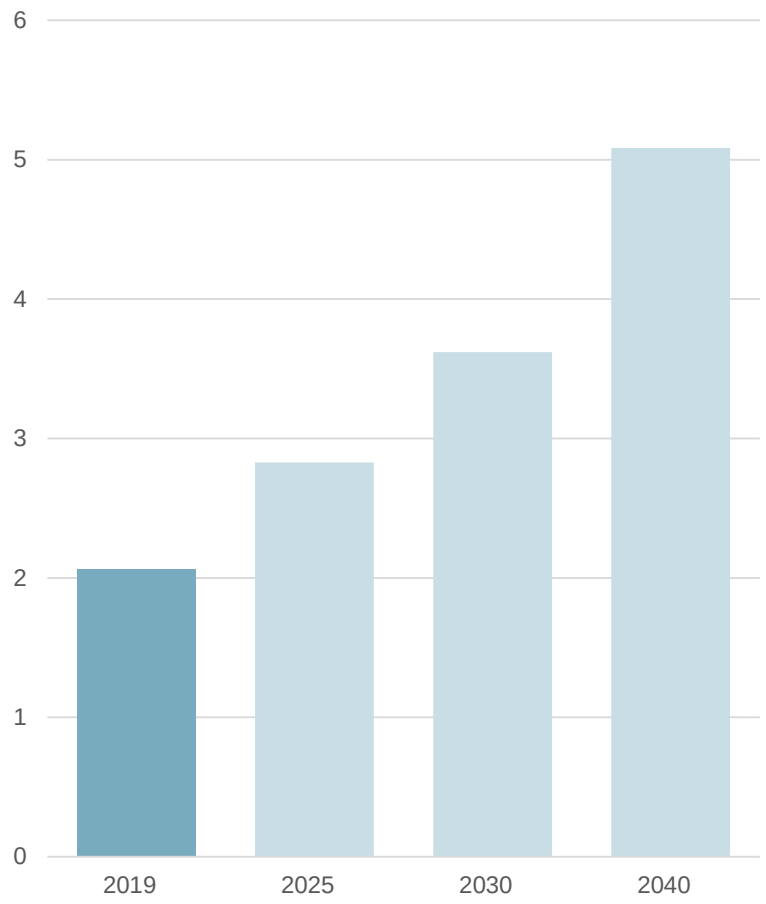
Additional technological advancements & government policy could advance CCUS economics for other facilities

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.

Attractive Potential for Liquid Biofuels

Policy support & efficient infrastructure important to increasing adoption of ethanol, biodiesel & other low-carbon fuels

GLOBAL BIOFUELS DEMAND OUTLOOK
million barrels per day



Stated policies scenario projects:

~75% or 1.5 mmbbld increase by 2030

~150% or 3.0 mmbbld increase by 2040

Even more in a 2-degree scenario

~40% of growth from the U.S. & China

Policies such as the U.S. Renewable Fuel Standard & China's E10 program underpin this level of increase

5x more investment required each year

Over $10 billion projected to be spent on production capacity through 2030 versus just $2 billion in 2019

Source: International Energy Agency, World Energy Outlook, October 2020 (Stated Policies Scenario).
Note: Statistics relative to 2019, the latest actual available.

Substantial Existing Capabilities at Our Terminals & Products Assets

Includes substantial blending, pipeline, terminaling & export capabilities for ethanol & other biofuels

	Ethanol	Biodiesel	Renewable Diesel
Our existing assets offer many biofuels capabilities:	Fuel-grade ethanol breakout (e.g., unit-train transloading) & blending into gasoline (e.g., truck racks) Multi-modal ethanol hubs, including our Argo terminal which is the CME pricing & trading point for Chicago ethanol	Biodiesel services include transloading, storage & blending in tank, at the truck rack & in pipeline manifolds Project currently under construction at Barstow Terminal (CALNEV); also includes some RD capability	Services include storage, blending, marine, rail & truck handling Terminals segment services focused in Midwest & Lower River area Products segment can handle up to R5 blends on diesel systems[a]
In 2020, our Products & Terminals segments handled:	~240 mbbld	~13 mbbld	~5 mbbld
2020 U.S. production[b]:	~902 mbbld	~118 mbbld	

Evaluating multiple opportunities to establish hubs for renewable products / biofuels

Source: U.S. production from EIA Weekly U.S. Oxygenate Plant Production of Fuel Ethanol (1/6/2021) & Monthly Biodiesel Report (12/31/2020).

a) Based on current regulatory requirements. Absent regulatory requirements, capability would be R0 to R100 as renewable diesel is chemically indistinguishable from hydrocarbon diesel.

b) Biodiesel represents average daily volume for the 10 months ended 10/31/2020, the latest available as of January 2021.

Our Multi-Faceted ESG Approach

Recognized as an industry leader & for ongoing improvements

INVEST integrity management & maintenance programs

- Safety-focused
- Outperform industry averages in almost all safety & release related categories
- Projects to minimize our impact on biodiversity within our operating areas

MANAGE integrity, accountability, safety, excellence

- Employees & representatives expected to behave ethically & responsibly
- Employ sustainable business practices

REPORT provide transparency to stakeholders

- Released third ESG Report, including 1.5-2°C scenario & physical risk analysis
- Utilizing SASB & TCFD frameworks
- Third party assurance & testing by internal audit
- Plan to report company-wide Scope 1 & 2 emissions in 2021

COLLABORATE engage communities & service suppliers

- Support & regularly interact with local communities
- Foster safety-focused culture among our service suppliers
- Strive to build relationships with diverse suppliers

Sustainalytics ESG risk rating[a]

#1
in Refiners & Pipelines industry group (182 companies)

#1
in Oil & Gas Storage & Transportation subindustry (95 companies)

Featured in multiple ESG indices

FTSE4Good Index
series for ethical investments

MSCI USA ESG Leaders Index
targeting the highest ESG rating in each sector of parent index

S&P 500 ESG Index
measuring performance of companies meeting sustainability criteria

Recently named on Newsweek's list of America's Most Responsible Companies 2021 & upgraded to BBB ESG rating by MSCI

Note: SASB = Sustainability Accounting Standards Board. TCFD = Task Force for Climate-Related Disclosure.
a) As of 1/8/2021.

Long-Standing Commitment to Reducing Emissions

25+ year track record

Evaluate new opportunities

- Work with organizations like DOE, EPA, & PRCI on studies & technology evaluations
- $712k invested in GHG emissions & other climate-related R&D over past three years

Set reduction goals for 2020

- Reduce methane emissions by 2.25 bcf or ~1.2 MMT CO2e
- Part of ONE Future & EPA's Natural Gas STAR & Methane Challenge

Employ programs & technology

- Energy management programs reduce our electricity usage
- Implement technology like satellite & aerial methane detection, & laser absorption monitoring

Disclose

- Rated in top quartile of midstream sector for methane disclosures & quantitative targets by EDF

Surpassed methane emissions intensity target[b]

0.03% vs. 0.31%

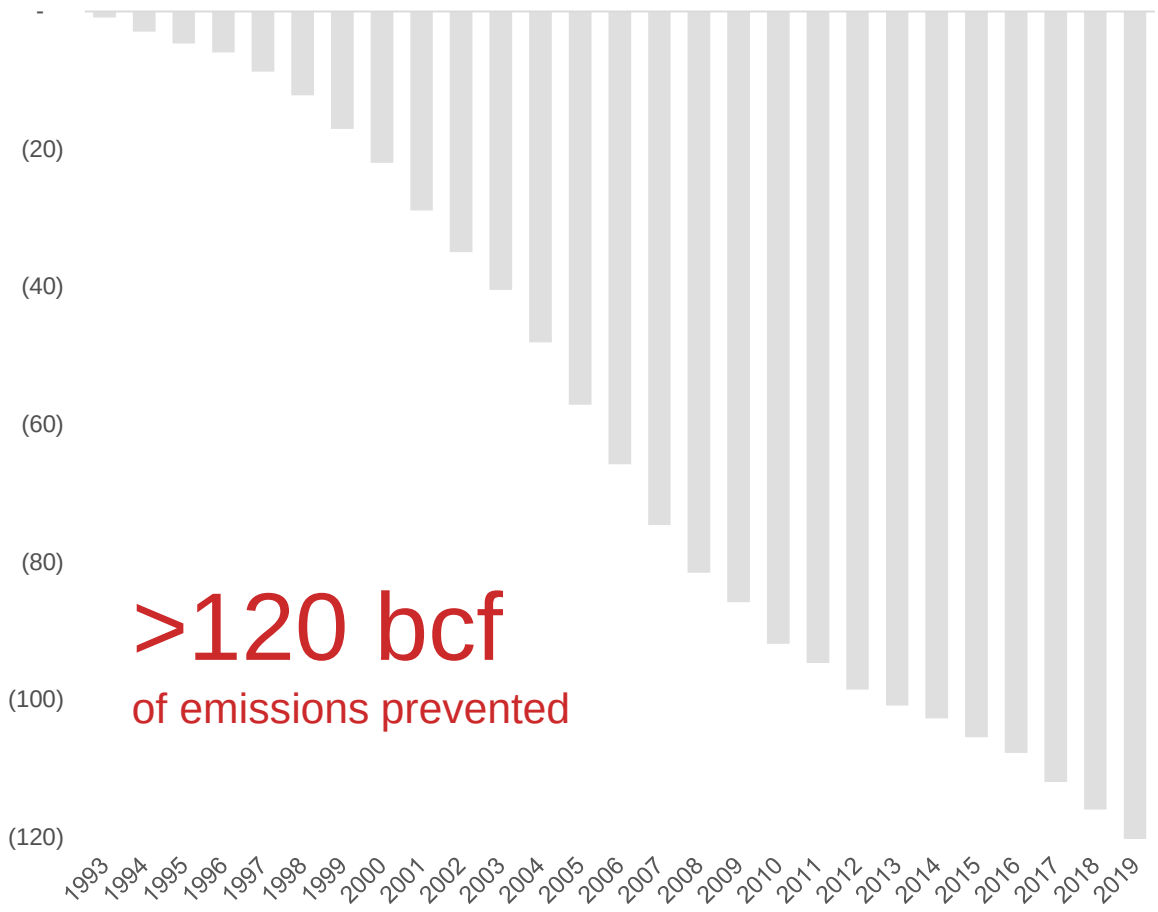
target for natural gas transmission & storage assets in 2019

7

years ahead of schedule

SUCCESSFUL METHANE EMISSIONS REDUCTIONS[a]

bcf, cumulative across our operations reported to EPA Natural Gas STAR & Methane Challenge programs



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

a) Emission reductions are emissions mitigated or avoided that would otherwise have been emitted.

b) Kinder Morgan's allocation of One Future methane emissions intensity target.

Building a Diverse, Inclusive & Respectful Workplace

Investing in our people & communities where we operate

Talent

45% female or minority
representation in Executive Leadership helps bring a diverse set of perspectives to the table

Annual training required
on our Code of Business Conduct & Ethics to reinforce our expectations for ALL of our employees

Leadership programs
in place for newly promoted & recently hired leaders, as well as programs to develop new bench strength

Diversity

- Identify minority & female candidates for senior positions as part of annual succession planning efforts
- Developing plans to enhance diversity & equality of opportunity in hiring, development & promotion decisions
- Seek diverse applicants through job fairs & job sites focused on women, minorities, veterans & individuals with disabilities
- Partner with non-profits Cristo Rey, Genesys Works & INROADS to provide meaningful work to high school students in underserved communities & increase minority & female representation in our internship program

Community

>$6.8 million donated
from 2017 to 2019 through the Kinder Morgan Foundation, as well as corporate & project-related community investments

Connect.Inspire.Give.
program offers employees & their families a diverse range of community volunteer opportunities

6.6 million students
served through activities donated to by Kinder Morgan Foundation in 2018 & 2019

Note: Executive Leadership refers to “executive officers” as defined by Rule 3b-7 under the Securities Exchange Act.

Positioned for the Future of Energy

Our vast network of strategically-located energy infrastructure will continue delivering energy for decades to come

Moving fuels of today

U.S. exports help meet global demand from emerging economies who need affordable access to modern energy

Natural gas can rapidly lower emissions from the global power & industrial sectors which still rely heavily on coal

Flexible storage & delivery of natural gas facilitates increased use of renewables while avoiding power outages

Our assets facilitate renewable blends with traditional fuels

& the future

Many emerging renewable fuels are complementary to their traditional counterparts & can be moved on our assets today

Economic & timely option to upgrade or repurpose pipeline & storage assets to handle a wider variety of low carbon fuels

We will take a disciplined approach when evaluating new renewables opportunities

It would be difficult & costly to duplicate our footprint with new builds

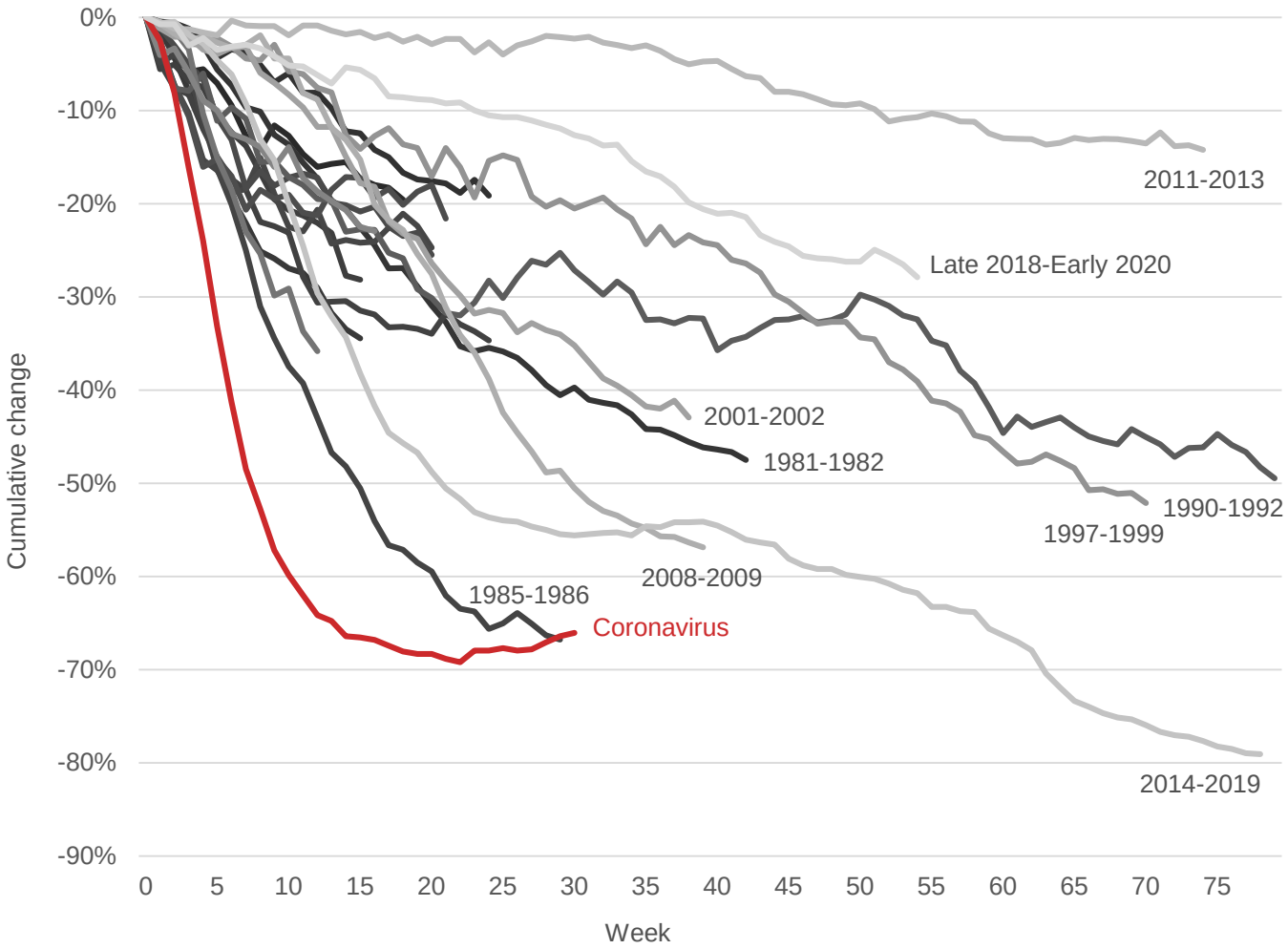
Essential to a clean, reliable, affordable energy future

STRATEGY & BUSINESS REVIEW

2020: a Remarkable Year in Energy

In the last century, only World Wars & the Great Depression have produced larger declines in global energy demand

U.S. RIG COUNT DECLINE EVENTS SINCE 1975



Globally, it's estimated that in 2020:

- Energy demand declined 5%
- Natural gas demand dropped 3%
- Oil demand contracted 8% with aviation fuel the worst affected
- Coal demand declined 7%
- Energy-related CO_2 emissions fell by 7%

While in the United States:

- Natural gas consumption declined over 2%
- Liquid fuels consumption dropped 12%
- Upstream spending on U.S. shale declined 50%

Despite severe disruptions, the critical nature of energy moderated the overall demand impact

Source: Baker Hughes, Macquarie Macro Strategy, October 2020; International Energy Agency, World Energy Outlook, October 2020; U.S. EIA Short-Term Energy Outlook, January 2021.

We Weathered the 2020 Storm while Improving Shareholder Value

Committed to being disciplined stewards of capital

$700 million	~30% reduction in discretionary capital compared to budget
$190 million	saved in operating costs & sustaining capital
$200 million	improvement in distributable cash flow after discretionary capital vs. budget
$990 million	net debt reduction YoY
$2.4 billion	paid to shareholders in dividends; 9% increase over 2019
1.9x coverage	of declared dividend with distributable cash flow

During the pandemic, we also successfully completed the Permian Highway Pipeline & kept our critical infrastructure running

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

$1.5 billion backlog with 60% allocated to natural gas projects

Allocated ~70% of 2020 expansion capex to natural gas & LNG projects

Invested in biodiesel, ethanol & renewable diesel projects

Financial flexibility

4.6x 2021 budgeted Net Debt / Adjusted EBITDA[(a)] consistent with 4.5x target

Low cost of capital

Mid-BBB credit ratings

Ample liquidity

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.

Efficiency Project Resulted in Annual Savings of ~$100 million

Our already efficient & lean organization is always looking for ways to improve

- In July, appointed James Holland to new COO role for enhanced focus on operations & ESG
- Also announced that the COO would lead an examination of cost-effective changes in organizational structure
- Several functions were centralized & will no longer be operating under business units

INTEGRITY MANAGEMENT	EHS	ESG	EHS SYSTEMS & REPORTING	EHS AUDIT *consolidated with internal audit*	ENGINEERING SERVICES	PROJECT MANAGEMENT

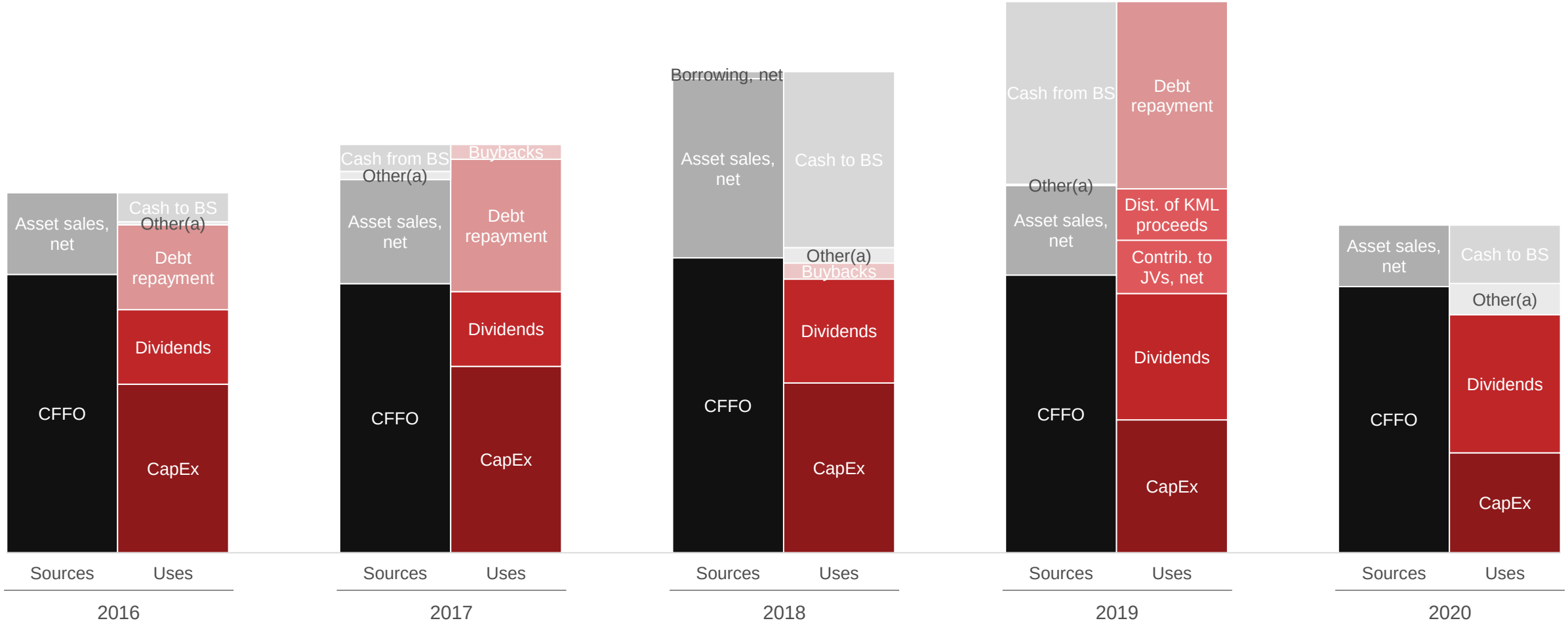
- Centralization of these functions generated significant efficiency gains by bringing our experts together & instituting best practices across the organization
- The reorganization resulted in annual savings of ~$100 million, primarily due to a ~5% workforce reduction focused on management & administrative roles which were reduced by ~14%
- Prevented over 200 involuntary severances (2% of the 5% reduction)
  - Offered voluntary severance
  - Filled open positions throughout the company with people who would have otherwise been on the severance list within their own organizations

Positioned for the long-term as an efficient, cost effective & safe operator of critical assets	*Embedded in our values, culture & budget process*

Self-Funding Capex & Dividends Since 2016

Opportunistic asset monetization enabled meaningful debt reduction

Generated $1.9 billion of free cash flow after dividends over last 5 years



Source: KMI GAAP Statement of Cash Flows. 2020 results are preliminary.

Note: Free cash flow = CFFO less capital expenditures. See non-GAAP Financial Measures & Reconciliations. "Asset sales, net" include the monetization of a 50% interest in Southern Natural Gas, Kinder Morgan Canada Limited (KML IPO & sale), Trans Mountain pipeline & U.S. Cochin pipeline. (a) Unless called out separately, "Other" includes (i) contributions to JVs, (ii) distributions from JVs included in cash flow from investing, (iii) net distributions to NCI, (iv) debt repayment, net of issuances, (v) share buybacks, (vi) the effect of FX on cash & (vii) other, net.

Highly-Contracted Cash Flows

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

CONTRACT MIX[a]

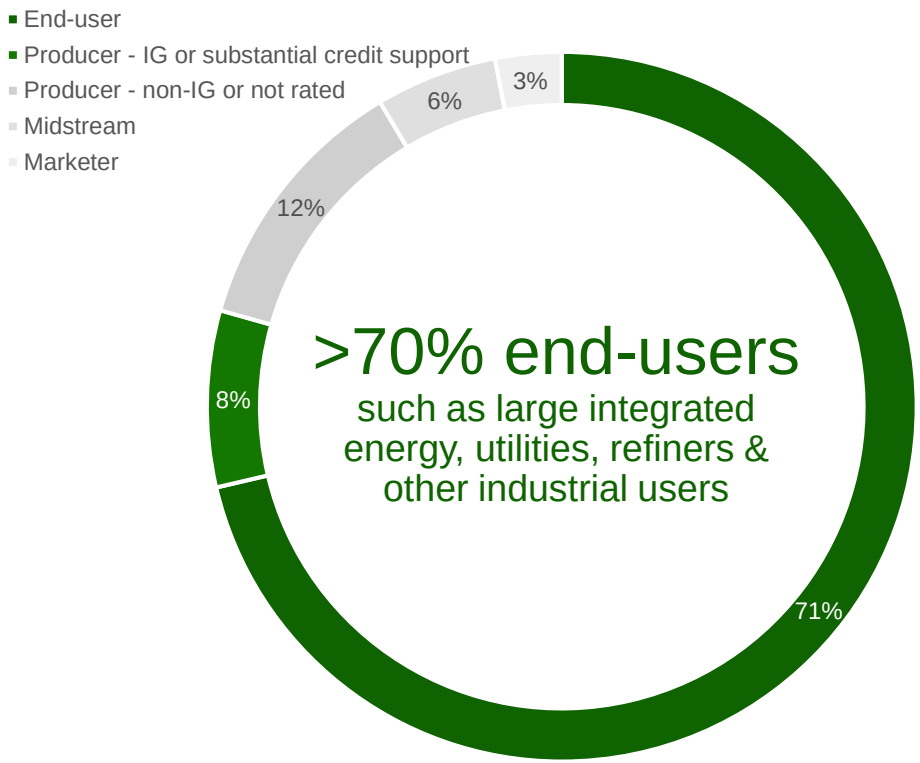
Contract type	Payment feature	Example assets	
68% Take-or-pay	Entitled to payment regardless of throughput Reservation fee for capacity	Jones Act tankers Natural gas interstate / LNG Natural gas intrastate (b) CO2 & transport Liquids terminals Crude pipes	100% 93% 83% 78% 74% 69%
25% Fee-based	Fixed fee collected regardless of commodity price Volumetric-based revenues	Crude G&P Refined products pipes Bulk terminals Natural gas G&P	93% 89% 68% 62%
4% Hedged	Disciplined approach to managing price volatility Substantially hedged near-term price exposure	EOR oil & gas (c)	80%
3% Other	Commodity-price based	EOR oil & gas (c) Crude pipes Natural gas G&P	20% 12% 10%

a) Based on Adjusted Segment EBDA per the 2021 budget. See Non-GAAP Financial Measures & Reconciliations.
b) Includes term sale portfolio.
c) Percentage of net crude oil, propane & heavy NGL (C4+) net equity production per the 2021 budget.

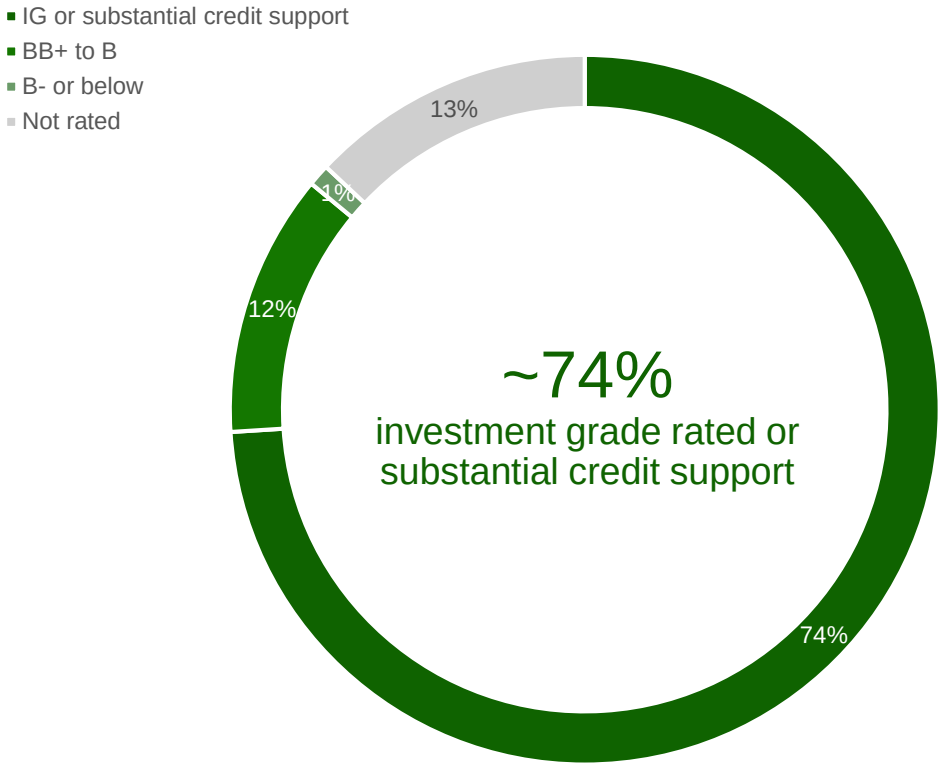
Customers Are Primarily End-Users of the Products We Handle

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

CUSTOMER TYPE



CREDIT RATING



Only ~1% 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 232 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.

Successfully Achieving Attractive Build Multiples

Established track record of leveraging our footprint & project management expertise

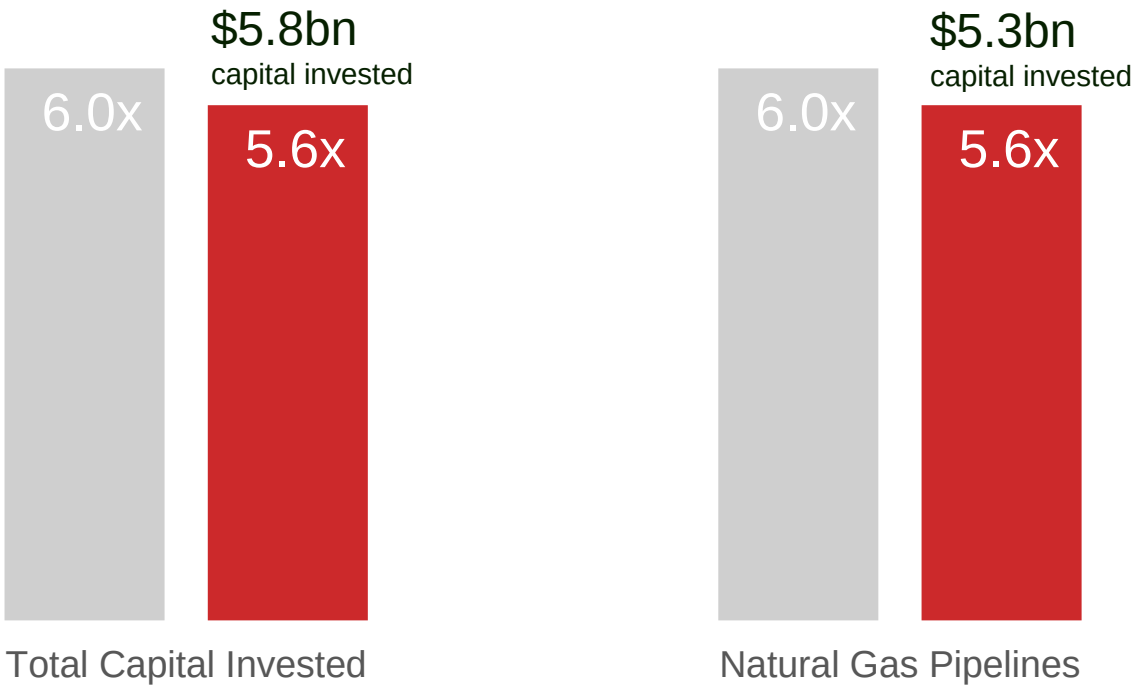
COMPETITIVE ADVANTAGES

- Expansive asset base — ability to leverage or repurpose steel already in the ground
- Connected to practically all major supply sources
- Established deliverability to primary demand centers — final mile builds typically expensive to replicate due to congestion
- Strong balance sheet & ample liquidity — internal cash flow available to fund all investment needs through 2021

Expansive footprint creates opportunities for differentiated returns

INVESTMENT MULTIPLES: PROJECTS COMPLETED 2018 – 2020

Capital invested / year 2 Project EBITDA[(a)]



Note: See Non-GAAP Financial Measures & Reconciliations.

a) Multiple reflects KM share of invested capital divided by Project EBITDA generated in its second full year of operations. Excludes CO_2 segment projects. Excludes KML projects.

Natural Gas Segment Overview

Connecting key natural gas resources with major demand centers

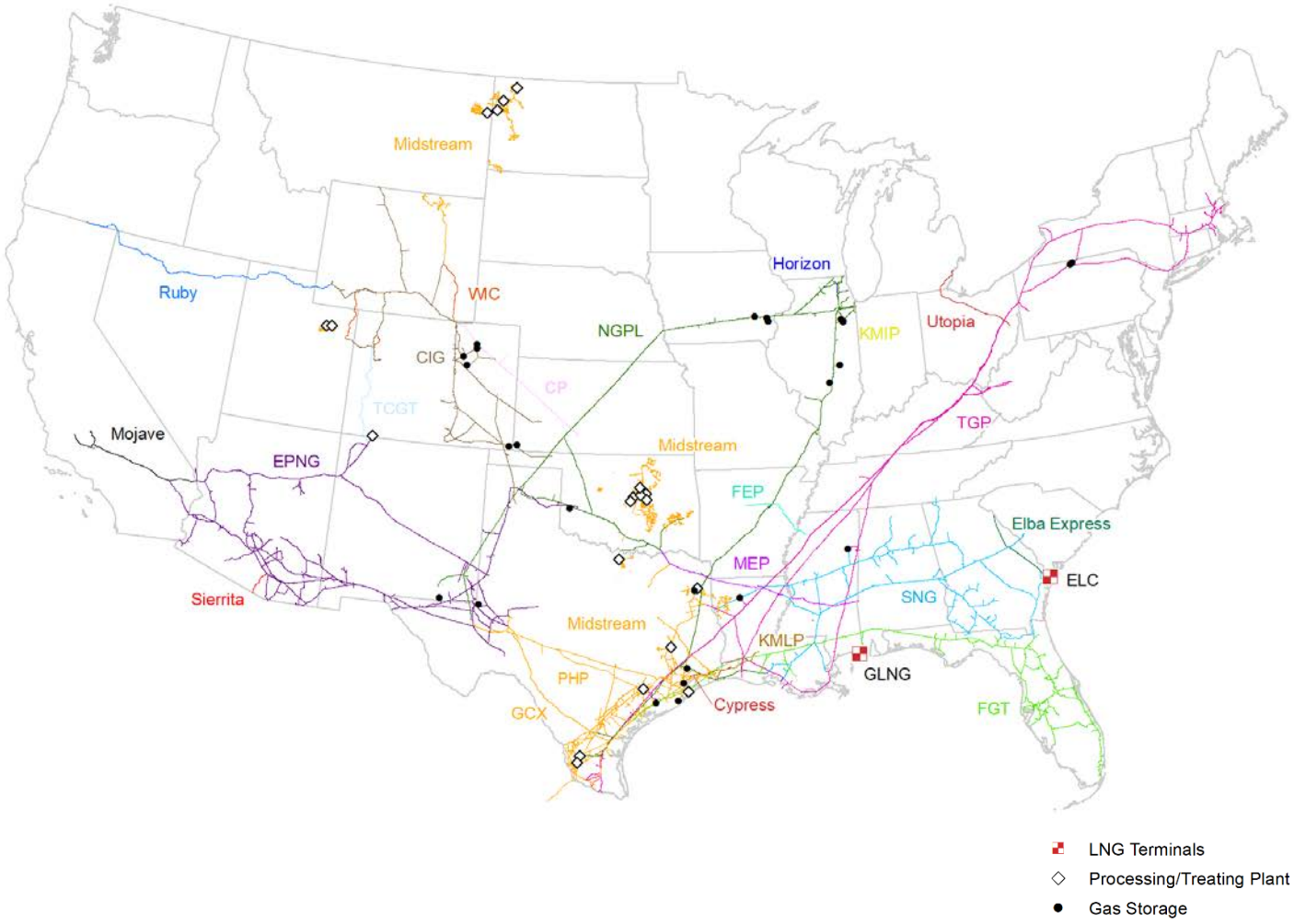
ASSET SUMMARY		
Natural gas pipelines:	~70,000	miles
NGL pipelines:	~1,200	miles
Natural gas transported (U.S. consumption & exports)		~40%
Working gas storage capacity:	659	bcf

2021 budgeted EBDA: $4.4 billion

Contributes ~60% of segment earnings & backlog

Connects effectively all major supply areas to key demand centers across the U.S.

Attractive expansion opportunities from significant existing footprint



Note: 2021 budgeted EBDA & earnings contribution based on 2021 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Leading the Way Out of the Permian

Excellent execution in face of global pandemic & substantial opposition

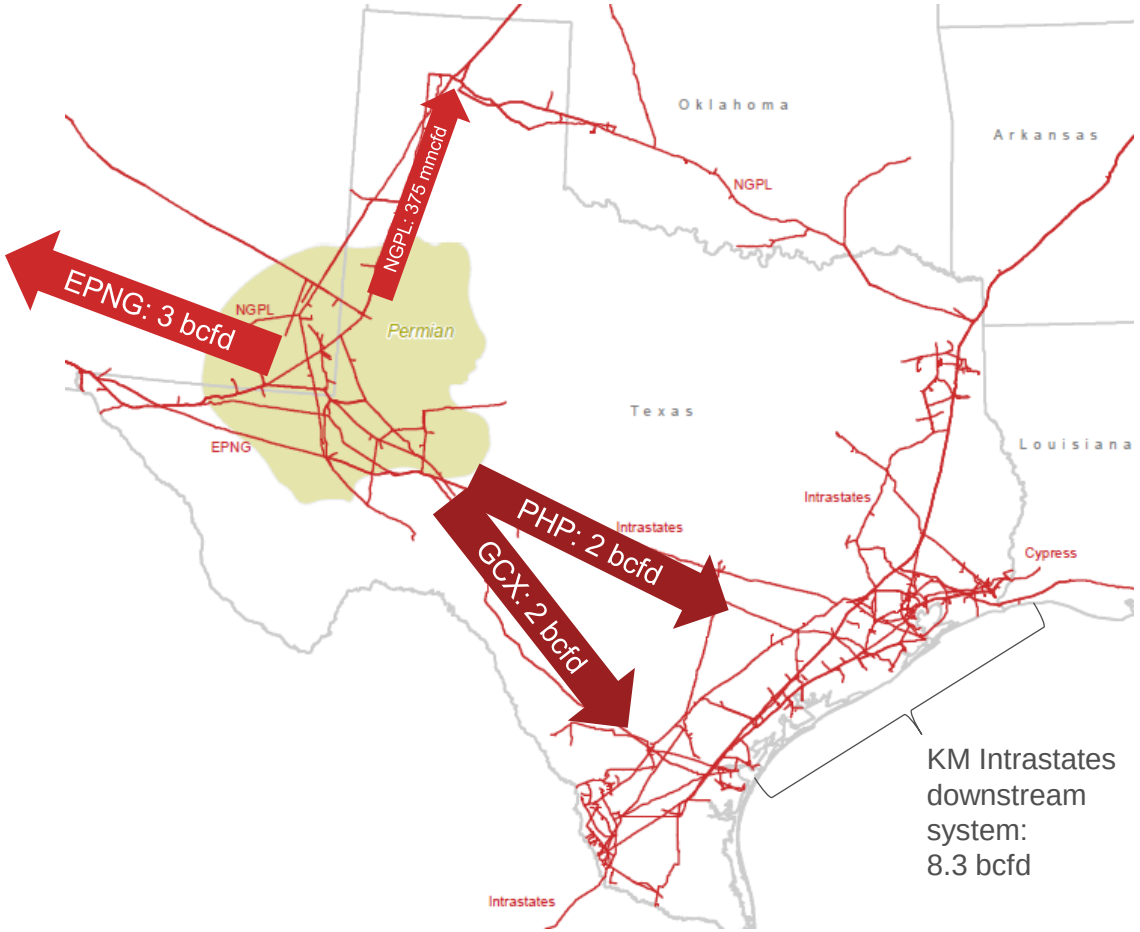
Leveraging existing footprint into new takeaway capacity

- Reaches across Texas & the Desert Southwest, connecting into major demand markets
- Our advantaged network offers broad end-market optionality with deliverability to Houston markets (power, petrochemical), substantial LNG export capacity & Mexico

Invested over $250 million across existing Texas Intrastates pipeline networks

- Supporting distribution of significant incremental volumes
- Increased capacity by ~1.4 bcfd
- Key to delivering Permian volumes into the U.S. Gulf Coast & Mexico markets

	Gulf Coast Express (GCX)	Permian Highway Pipeline (PHP)
Mainline:	450 miles of 42” pipeline	430 miles of 42” pipeline
Endpoint:	Near Agua Dulce	Near Katy
KM ownership:	34%	26.7%
Capacity:	2.0 bcfd	2.1 bcfd
Capital (100%):	$1.75 billion	~$2.2 billion
In-Service:	September 2019	January 1, 2021
Min. contract term:	10 years	10 years



Providing unparalleled takeaway capacity from the Permian basin to the Gulf Coast & Desert SW markets

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

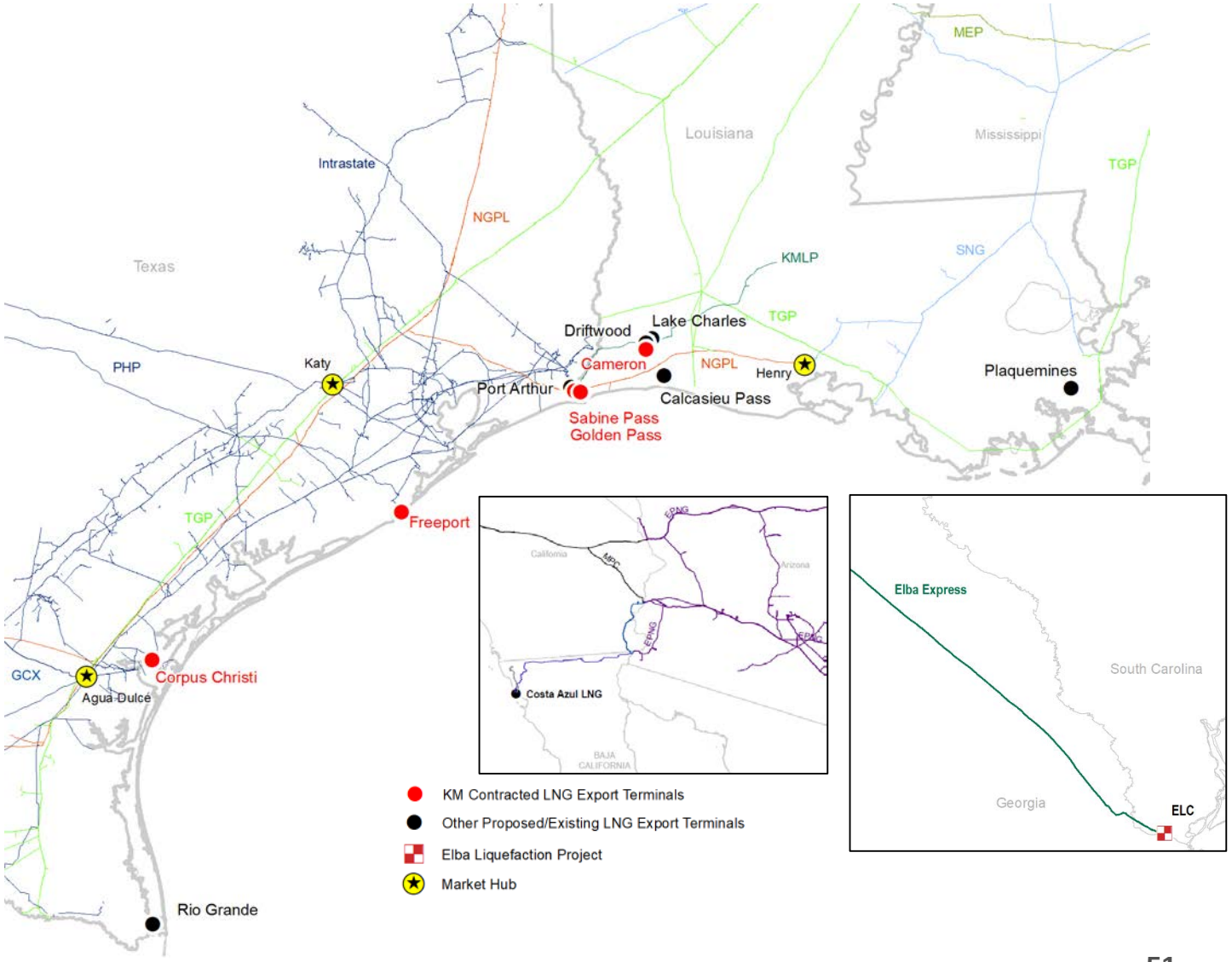
Premier deliverability

659 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
~ 4.4 bcfd	1.7 bcfd	17 years	2-4 bcfd

Also deliver ~1 bcfd of producer / marketer supply



Long-Term Growth Drivers: Natural Gas Segment

Opportunity for our unique last-mile pipeline connectivity, capitalizing on industry trends

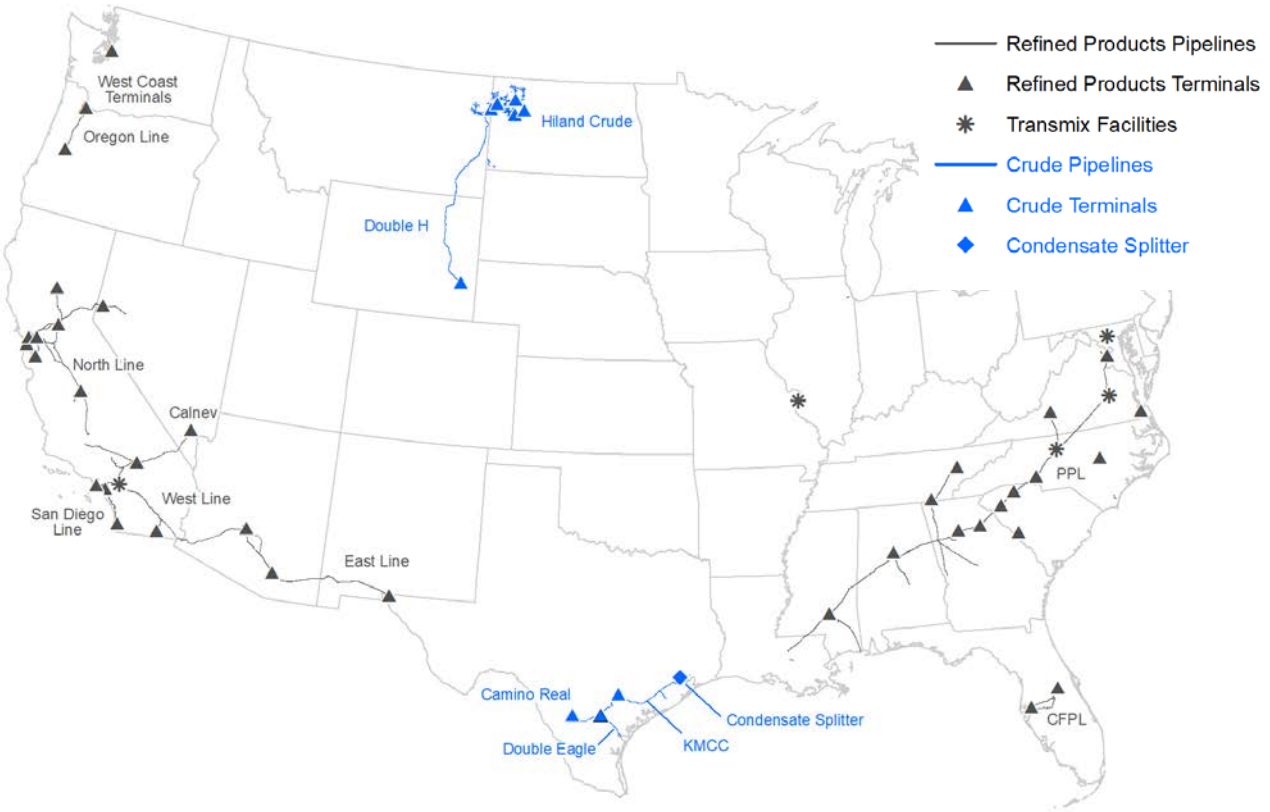
Exports	— LNG exports: pipeline & storage infrastructure supporting existing & new LNG development — Exports to Mexico: well-positioned to serve growing demand as critical infrastructure is built within Mexico
Storage (659 Bcf), linepack & additional capacity to support increasingly variable demand	— LNG export interruptions (e.g., due to weather, cargo cancellations, maintenance) — Complement variable renewable generation with responsive gas deliverability — Support daily & seasonal variability in exports to Mexico, where minimal storage exists — Balancing services to meet peak demand periods in summer & winter — Develop creative new services to address increasing variability in most demand sectors
Petrochemical & other industrial demand along the Gulf Coast	— Strategic pipeline footprint & storage to serve growing demand — Established deliverability & unique high pressure capability into major market centers
Leverage existing ~70,000 mile pipeline network	— Investment in facility modifications provides bi-directional flow opportunities — Extensions off of existing network to connect growing supply to end-use markets — Repurpose assets to serve new markets and/or maximize value - move higher margin products through pipes — Tailor premium non-ratable services to leverage operational flexibility — Brownfield solutions in increasingly challenging market for new construction — Provide transportation & storage for Responsibly Sourced Gas (RSG)
End-user / LDC demand growth	— Regional power generation opportunities, baseload growth, peaking & deliverability — Unique last-mile connectivity to LDC, electric generation & industrial markets
Well-positioned to move potential fuels of the future	— Renewable Natural Gas (RNG) — Hydrogen

Products Segment Overview

Strategic footprint with significant cash flow generation

ASSET SUMMARY

Pipelines:	~9,500	miles
2021 budgeted throughput[a]	~2.3	mmbbld
Terminals:	65	terminals
Terminals tank capacity	~39	mmbbls
Pipeline tank capacity	~16	mmbbls
Condensate processing capacity	100	mbbld
Transmix	5	facilities



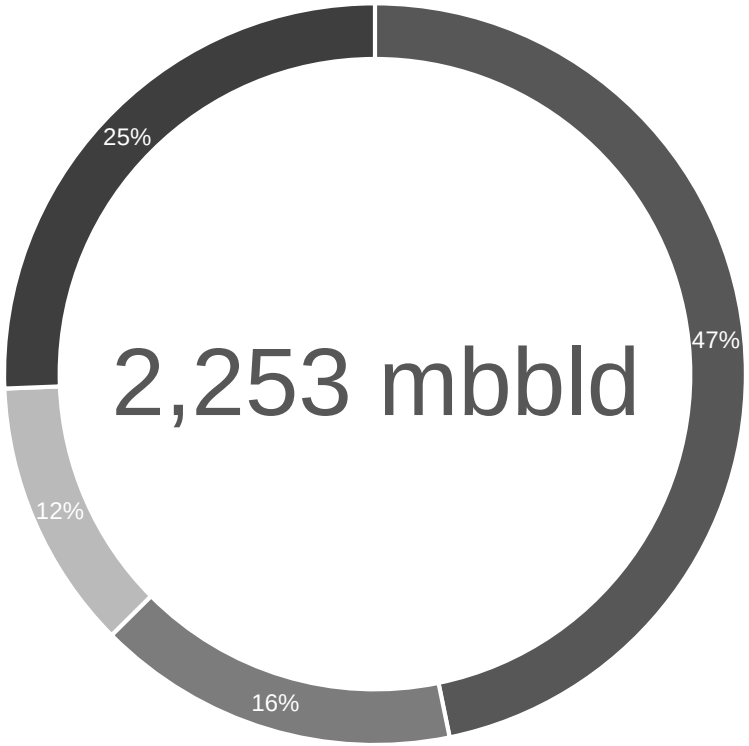
2021 budgeted EBDA of ~$1.2 billion
+13% over 2020

Note: 2021 budgeted EBDA based on Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
a) Volumes include SFPP, CALNEV, Central Florida, PPL (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering.

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

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.

West Coast Renewable Fuels Projects

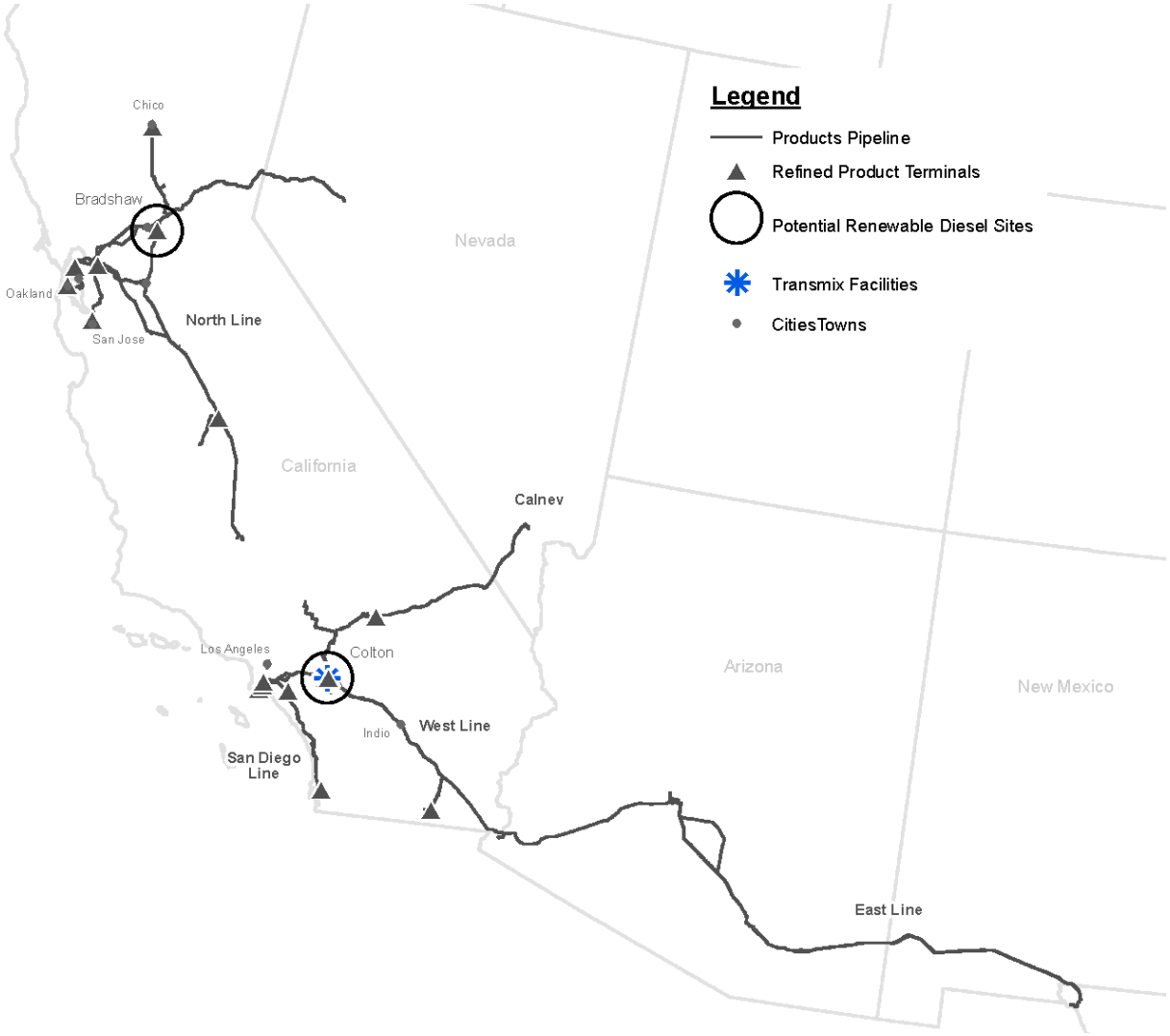
Developing infrastructure to secure renewable fuels

Market drivers

- Renewable Diesel (RD) has been driven by California subsidies
  - RIN credits
  - Low Carbon Fuel Standard (LCFS) credits
  - Blender's Tax Credit
  - Currently averaging approximately $3.00/gal for total credits (RIN+LCFS+ Blender's tax credits)
- State goals to reduce emissions
  - CARB has 2030 goal to reduce 1990-level GHG emissions by 40%
  - Oregon's Clean Transportation Fuel Standards program has aggressive goals for reducing carbon emissions

Potential project highlights

- Construction of new RD hubs in both Northern & Southern California
  - Approximately $90 million discretionary capex for all locations
  - Rail in renewable diesel / biodiesel
  - Segregated storage for renewable products
  - Opportunities to blend RD with both biodiesel & CARB diesel over the truck rack – providing increased high-value optionality to customers
  - Each hub location currently scoped for 20 mbbld renewable capacity with further expansion opportunities available
- Serving the entire California diesel market
- Biodiesel blend capabilities will increase from existing 5% limit to 20%



Note: RIN = Renewable Identification Numbers. CARB = California Air Resources Board.

Terminals Segment Overview

National terminaling network connecting our customers with domestic & international markets

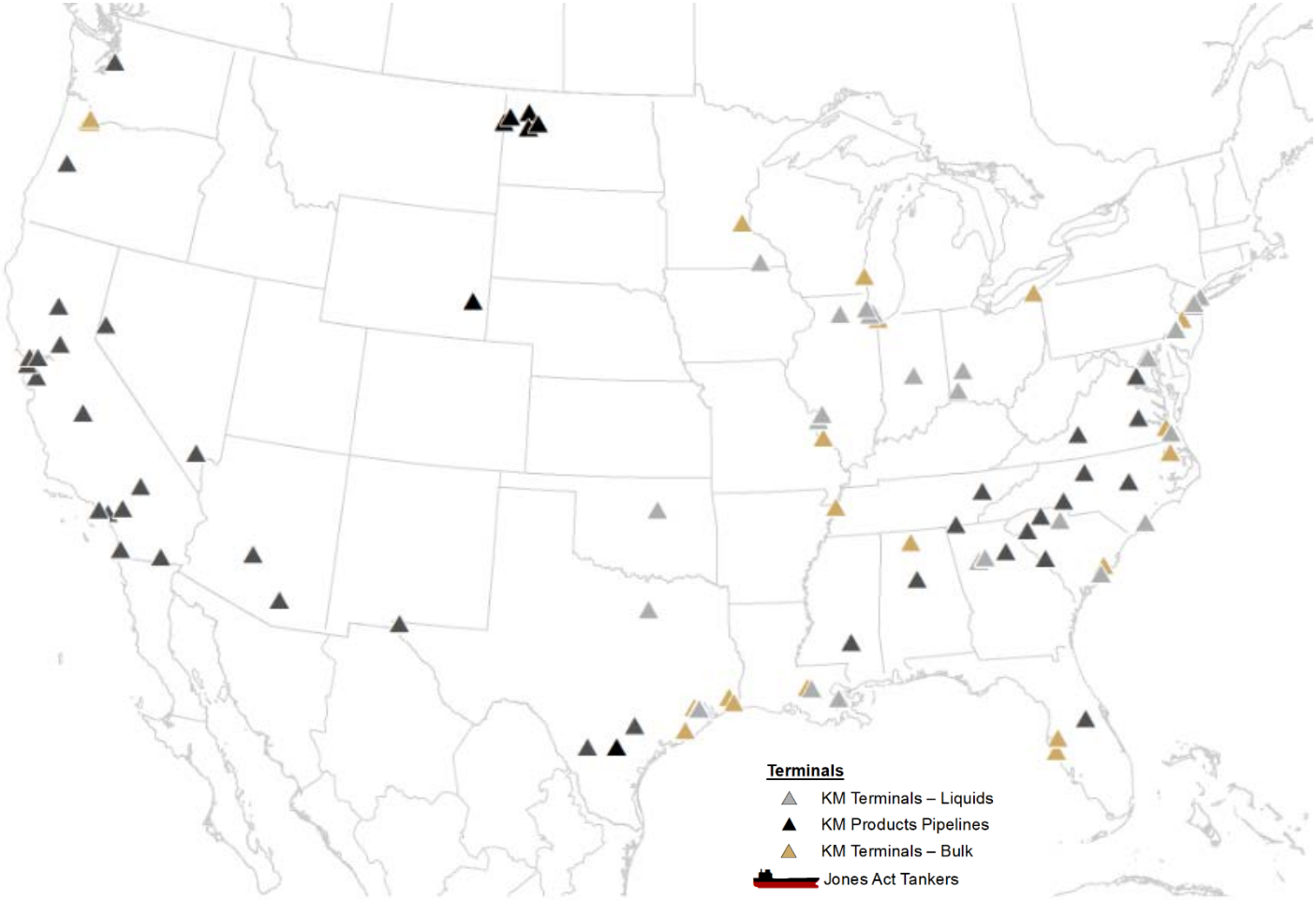
ASSET SUMMARY	# of terminals	capacity (mmbbls)
Terminals segment – Bulk	29	
Terminals segment – Liquids	50	80
Products segment	65	55
Total Terminals	144	135
Jones Act:	16 tankers	

2021 budgeted EBDA of ~$1.0 billion

Nationwide footprint focused on refined products, renewables & chemicals

Earnings driven by long-term contractual use of our assets

Infrastructure critical to our customers & their business



Note: 2021 budgeted EBDA based on Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

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

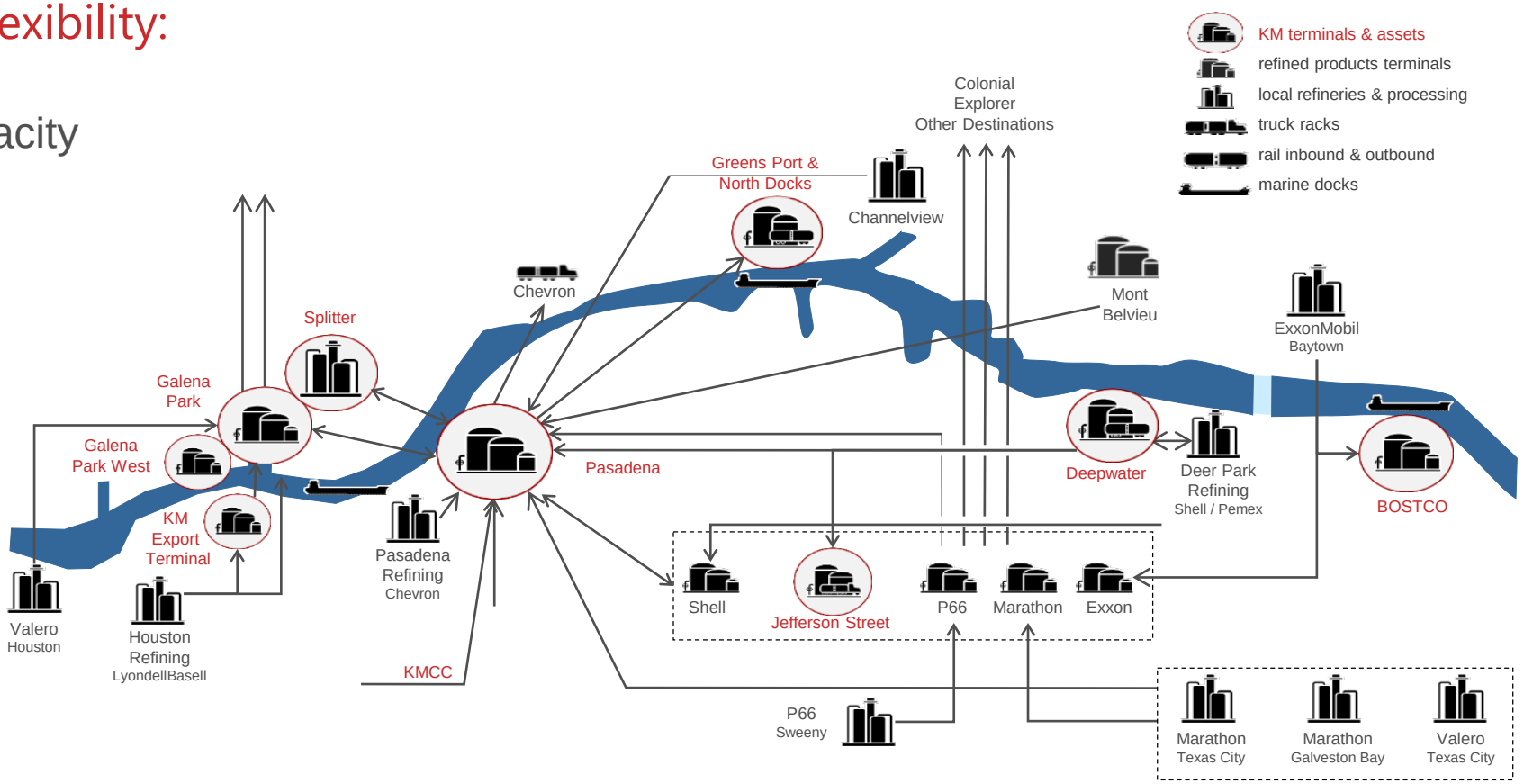
16 cross-channel pipelines

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.

Our Integrated Terminal Network on Houston Ship Channel

Industry leading capabilities in the world's most competitive refining & petrochemical center

Unmatched inbound connectivity

Refineries	Pipeline connectivity to all HSC refineries providing gasoline, distillate & blendstock supply	Pasadena Galena Park Kinder Morgan Export Terminal (KMET) BOSTCO
Chemicals	Pipeline & barge receipts of chemicals & gasoline blending components	Pasadena Galena Park
Ethanol	Unit train receipts of domestic ethanol production	Deer Park Rail Terminal Pasadena Jefferson Street Truck Rack
Mont Belvieu NGLs	Pipeline connectivity to Mont Belvieu fractionators for butanes & natural gasoline	Pasadena Galena Park

Value-added services

Aggregation, staging & storage services	Gasolines & distillates Black oils Chemicals Renewables	Pasadena, Galena Park, BOSTCO, KMET, Deer Park Rail Terminal, Jefferson Street Truck Rack, et al.
Product blending services	Gasolines & distillates	Pasadena, Galena Park, KMET
Bunker blending services	Residual oils Black oils Distillates	BOSTCO

Outbound market access

Truck rack	Local truck rack loadings to local markets	Jefferson Street Truck Rack
Pipelines	Pipeline origination to domestic markets	Pasadena Galena Park
Rail	Unit train origination of refined products to Mexico	Greens Port
Marine	Docks for export, as well as Jones Act domestic shipments	Pasadena Galena Park BOSTCO KMET North Docks

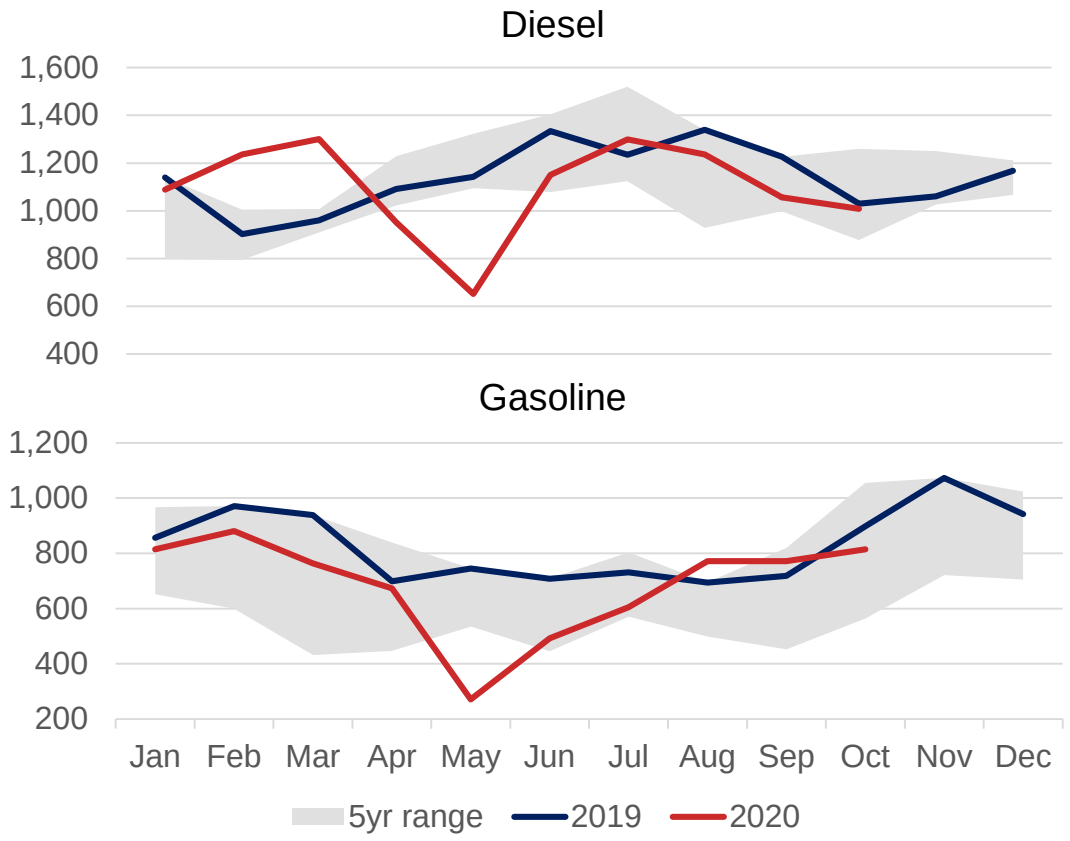
"More than just a bucket"

Value-added customer solutions for trading, blending, optimization & market access

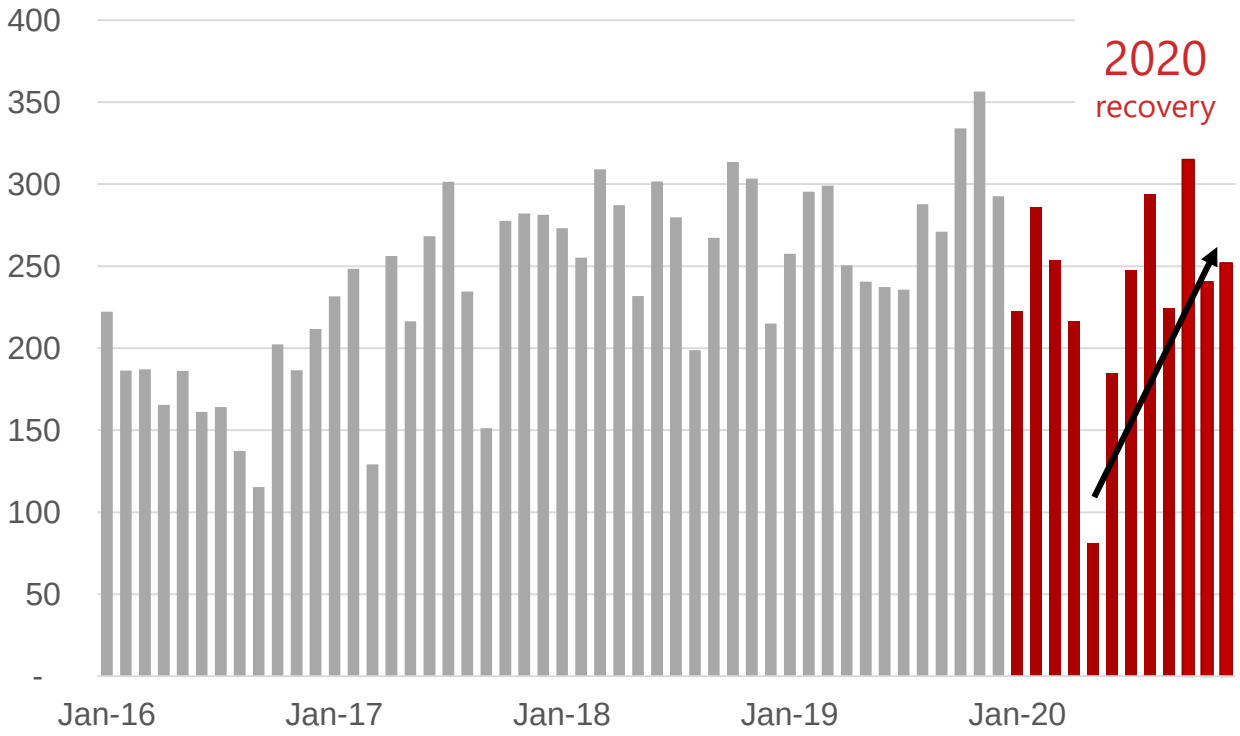
Leading Exporter of U.S. Gasoline & Diesel

COVID recovery & prospective long-term growth in USGC product exports

US GULF EXPORTS[a]
thousand barrels per day



OUR HOUSTON SHIP CHANNEL EXPORTS[b]
thousand barrels per day



Expanded dock capacities capable of up to 600 thousand bbld of export volumes

a) U.S. Energy Information Administration (through Sep-2020); diesel exports inclusive of total distillates; gasoline exports include both finished product & blendstocks.
b) KM internal data including export origination on both marine vessel & railcar.

CO_2 Segment Overview

World class, fully-integrated assets | CO_2 source to crude oil production & takeaway in the Permian Basin

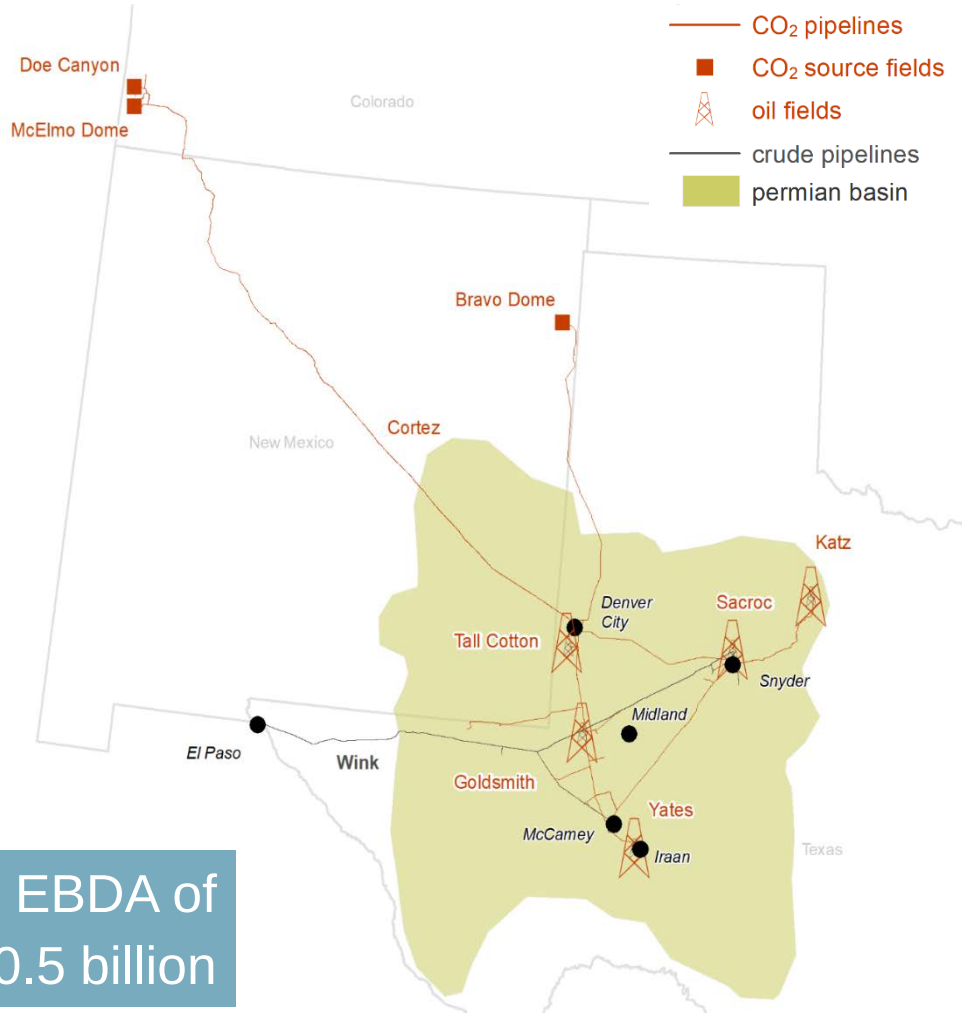
CO_2 & TRANSPORT

CO_2 Reserves	KMI Interest	NRI	Location	Est. OGIP tcf
McElmo Dome	45%	37%	SW Colorado	22.0
Doe Canyon	87%	68%	SW Colorado	3.0
Bravo Dome[a]	11%	8%	NE New Mexico	12.0

Pipelines	KMI Interest	Location	Capacity mmcfpd
Cortez	53%	McElmo Dome to Denver City	1,500
Bravo[a]	13%	Bravo Dome to Denver City	375
Central Basin (CB)	100%	Denver City to McCamey	700
Canyon Reef	97%	McCamey to Snyder	290
Centerline	100%	Denver City to Snyder	300
Pecos	95%	McCamey to Iraan	125
Eastern Shelf	100%	Snyder to Katz	110
Wink (crude)	100%	McCamey to Snyder to El Paso	145 mbbld

OIL & GAS

Crude Reserves[b]	KMI Interest	NRI	Location	Est. OOIP billion bbls
SACROC	97%	83%	Permian Basin	2.8
Yates	50%	44%	Permian Basin	5.0
Katz	99%	83%	Permian Basin	0.2
Goldsmith	99%	87%	Permian Basin	0.5
Tall Cotton	100%	88%	Permian Basin	0.7



2021 budgeted EBDA of ~$0.5 billion

Note: OGIP = Original Gas In Place. OOIP = Original Oil In Place. 2021 budgeted EBDA based on Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

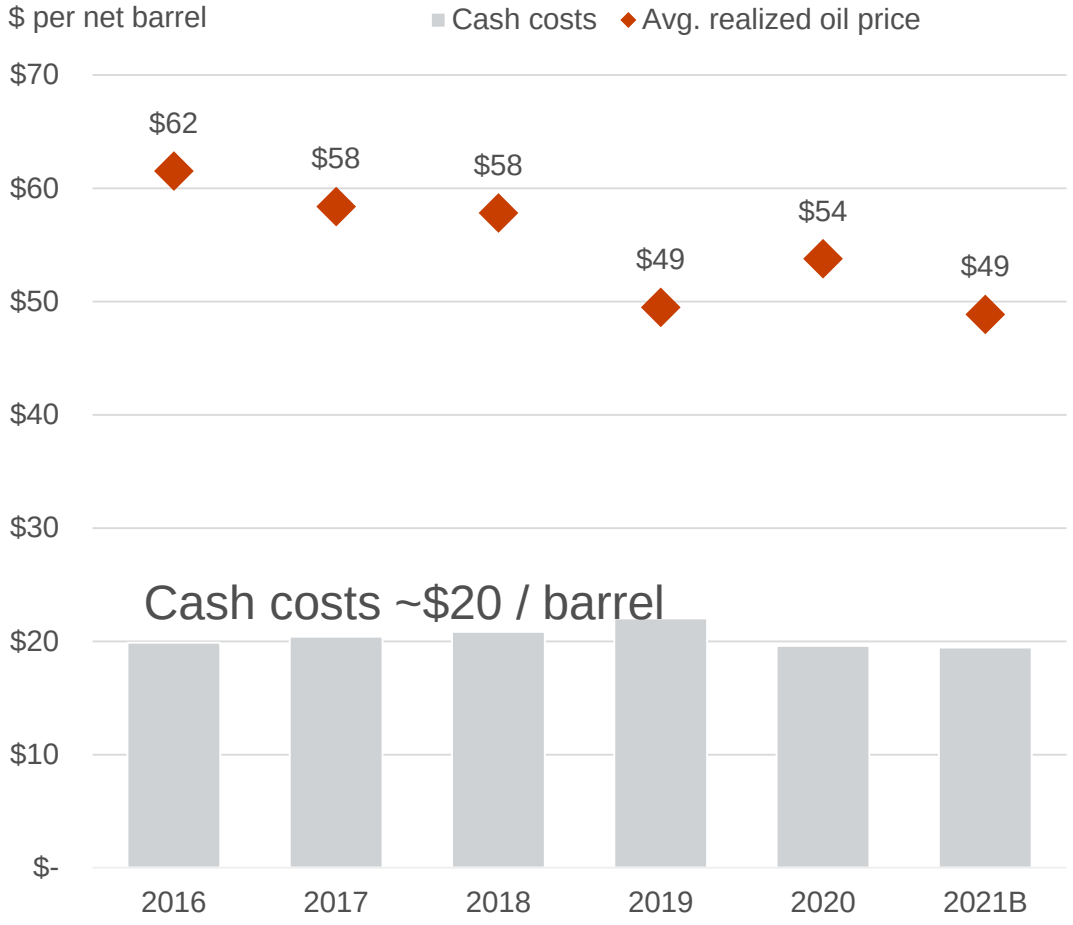
a) Not KM-operated.

b) In addition to KM's interests listed, KM has a 22%, 51% & 100% working interest in the Snyder gas plant, Diamond M gas plant & North Snyder gas plant, respectively.

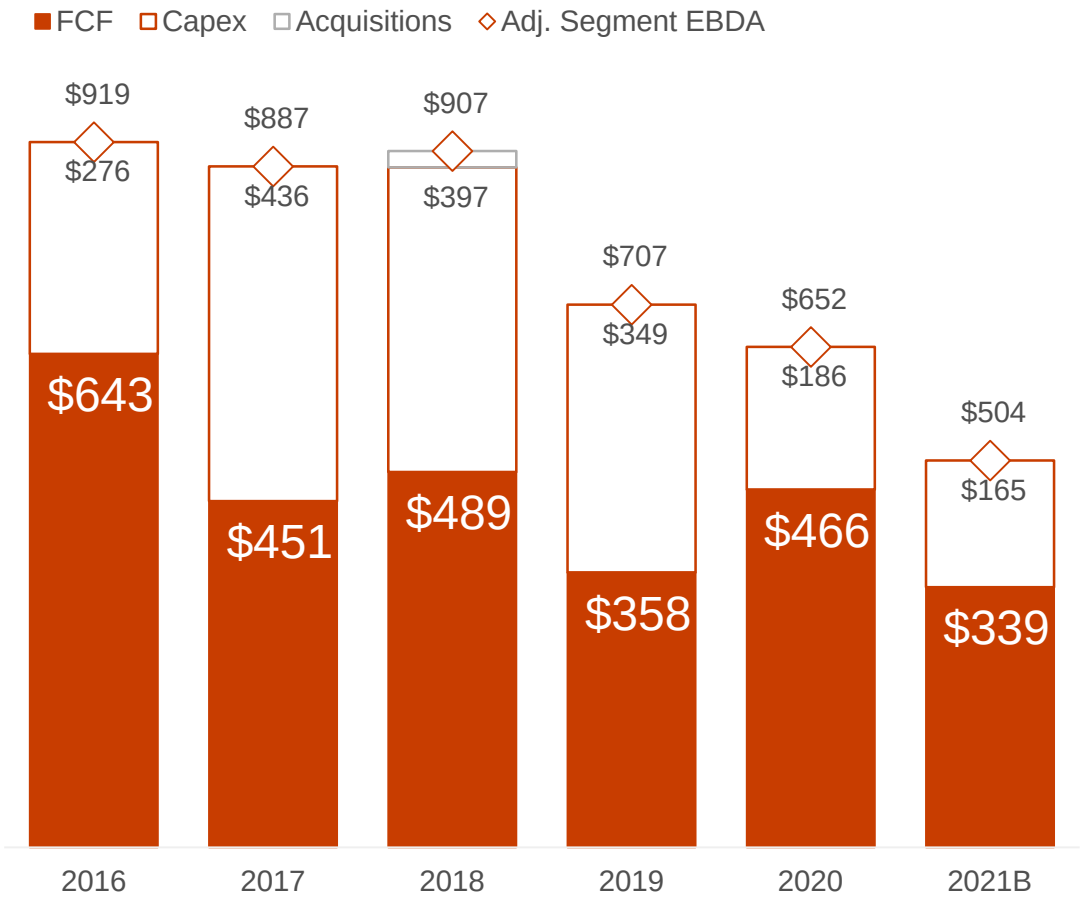
CO_2 Segment Consistently Generates Free Cash Flow

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

OIL & GAS CASH OPERATING COSTS & AVG. PRICE



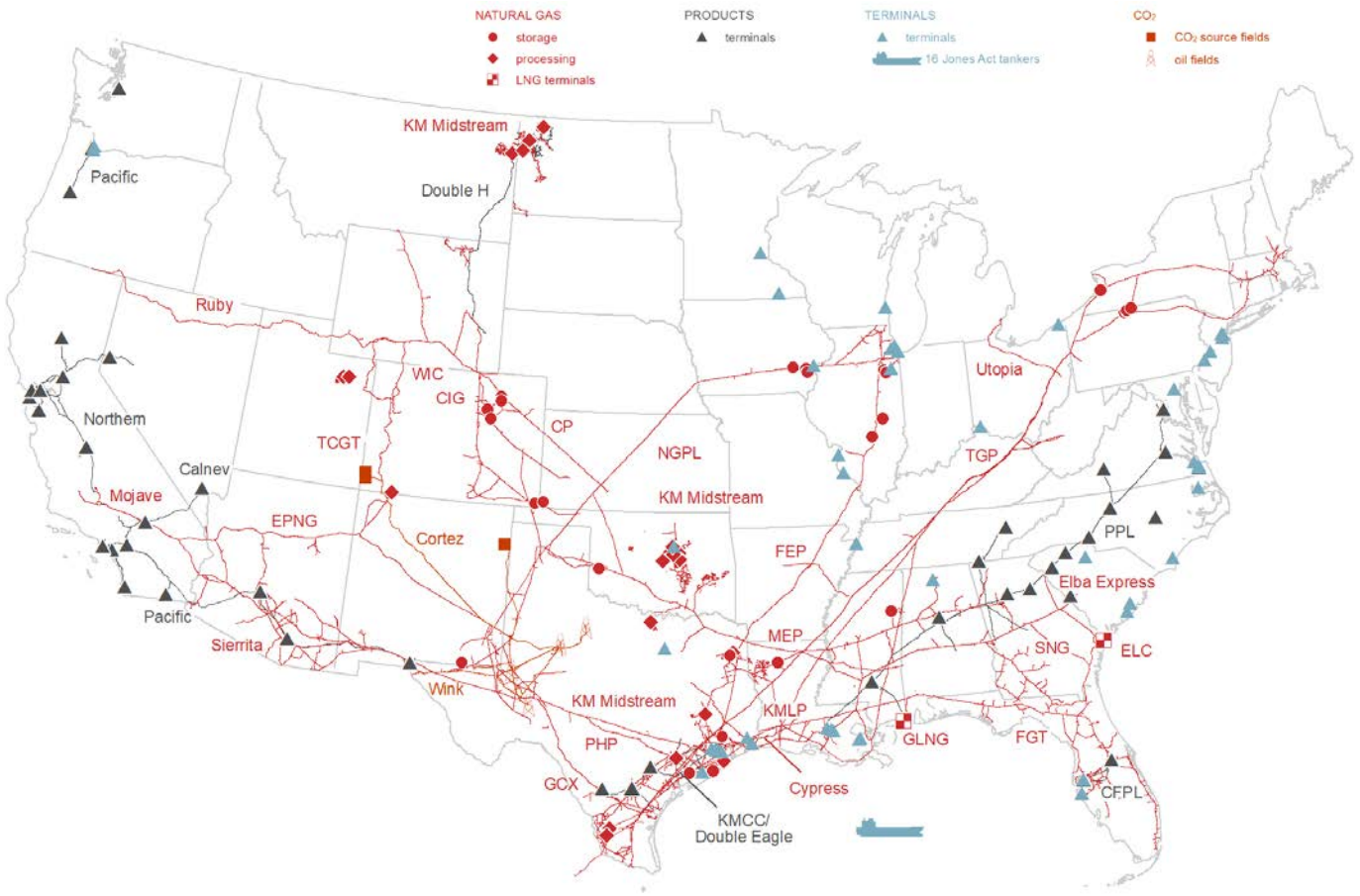
CO_2 SEGMENT FREE CASH FLOW $ millions



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

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]
- ~7% current yield & almost 2x coverage[b]
- Top 10 dividend yield in S&P500
- Dividends & capex funded with operating cash flow since 2016
- Expect up to $450 million available for share repurchases in 2021
- Highly-aligned management with ~13% share ownership

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

Note: See Use of Non-GAAP Financial Measures.
a) Based on Adjusted Segment EBDA per 2021 budget. See Non-GAAP Financial Measures & Reconciliations.
b) Based on 2021 budgeted DCF to dividend coverage ratio.

PANEL WITH **COO** & BUSINESS UNIT **PRESIDENTS**

2021 BUDGET

2021 Budget

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

Key metrics	2021 Budget	Variance to 2020	
Net income	$2.1 billion	~$2 billion	Increase due primarily to impairments taken during 2020
Adjusted EBITDA	$6.8 billion	(2)%	Lower re-contracting rates (mainly Ruby & FEP, as noted for the last couple of years), lower oil volumes, lower realized oil prices & lower capitalized overhead Partially offset by projects placed in service, increased refined product volumes & a corporate-wide organizational efficiency & effectiveness project Also impacting DCF is higher anticipated sustaining capex & lower interest expense
Distributable Cash Flow (DCF)	$4.4 billion	(3)%	
Discretionary capital[a]	$0.8 billion		
Dividend / share[b]	$1.08	3%	
Year-end Net Debt / Adj. EBITDA[b]	4.6x	-	

$1.2 billion	DCF in excess of discretionary capital[a] & dividends
$450 million	Up to $450mm available for share repurchases

Note: See Non-GAAP Financial Measures & Reconciliations.

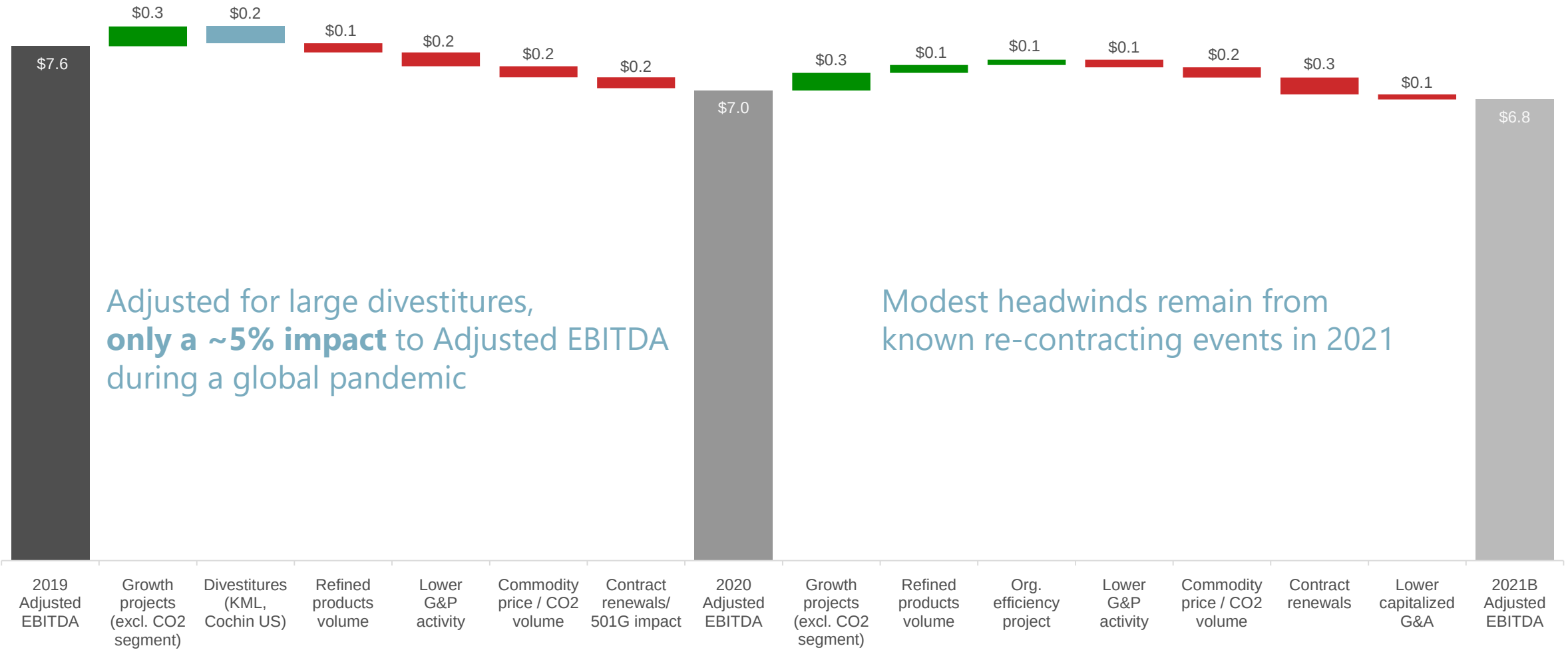
a) Includes growth capital & JV contributions for expansion capital, debt repayments & net of partner contributions for our consolidated JVs.

b) No share repurchases assumed in 2021 budget.

Stable Foundation of Cash Flows through Commodity Cycles

Diversified footprint of essential assets limits downside, even in extreme downturn events

$ billions



Adjusted for large divestitures, **only a ~5% impact** to Adjusted EBITDA during a global pandemic

Modest headwinds remain from known re-contracting events in 2021

Note: See Non-GAAP Financial Measures & Reconciliations. For a reconciliation of 2019 & 2020 Adjusted EBITDA to its comparable GAAP measure, please see our press release dated January 20, 2021, available on our website.

2021 Budget

Assumptions & highlights

SEGMENT	YoY EBDA[a]	KEY DEVELOPMENTS FROM 2020
Natural Gas	-1%	— Full year contribution from PHP & other expansions — TX Intrastates growth projects & increased margin — Unfavorable re-contracting impacts (FEP, Ruby & others) — Lower drilling activity on G&P assets (South and North TX, KinderHawk)
Products	+13%	— Refined product volume growth (+15%) — Favorable oil pricing impact — Refined products: FERC index escalator — Lower crude & condensate re-contracting (Double H & KMCC)
Terminals	+4%	— Volume recovery (+20% Liquids, +16% Bulk) — Contributions from Gulf area expansion projects — Sale of Watco preferred/common equity — Unfavorable Jones Act vessel contract renewals
CO_2	-23%	— Lower realized oil price — Lower crude & CO_2 volumes

Interest expense – 3-month LIBOR averages 0.21% for the year, based on approximate forward curve at time of budget

Cash taxes – do not expect to incur any material U.S. federal cash income taxes in 2021

a) Business segment percentage increase / (decrease) is 2021B to 2020A change in Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

2021B Net Income & Distributable Cash Flow (DCF)

in millions, except per share

	2021 Budget	2020 Actual	Change $	Change %
Net income attributable to Kinder Morgan, Inc. (GAAP)	**$ 2,109**	**$ 119**	**$ 1,990**	**NM**
Total Certain Items	(11)	1,892	(1,903)	(101%)
Adjusted Earnings[a]	**2,098**	**2,011**	**$ 87**	4%
DD&A and amortization of excess cost of equity investments for DCF[b]	2,557	2,671	(114)	(4%)
Income tax expense for DCF[a,b]	659	670	(11)	(2%)
Cash taxes[c]	(79)	(68)	(11)	(16%)
Sustaining capital expenditures[d]	(792)	(658)	(134)	(20%)
Other items[e]	2	(29)	31	107%
DCF	**$ 4,445**	**$ 4,597**	**$ (152)**	**(3%)**
	-	-		
Weighted average shares outstanding for dividends[f]	2,279	2,276	3	0%
Basic and diluted earnings per share	$ 0.92	$ 0.05	$ 0.87	NM
Adjusted EPS	$ 0.92	$ 0.88	$ 0.04	5%
DCF per share	$ 1.95	$ 2.02	$ (0.07)	(3%)
Expected/Declared dividend per share	$ 1.08	$ 1.05	$ 0.03	3%
Excess DCF above declared dividend	$ 1,984	$ 2,207	$ (223)	(10%)

3% dividend increase while maintaining healthy dividend coverage

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) Includes cash taxes from JVs of $67 million and $62 million in 2021 and 2020, respectively.
d) Includes sustaining capital expenditures from JVs of $119 million and $114 million in 2021 and 2020, respectively.
e) Includes non-cash pension expense and non-cash compensation associated with our restricted stock program.
f) Includes 15 million and 13 million average unvested restricted shares that participate in dividends in 2021 and 2020, respectively.

2021B Adjusted Segment EBDA & Adjusted EBITDA

$ in millions

	2021 Budget	2020 Actual	Change $	Change %
Natural Gas Pipelines	$ 4,419	$ 4,466	$ (47)	(1%)
Products Pipelines	1,157	1,027	130	13%
Terminals	1,032	990	42	4%
CO_2	504	652	(148)	(23%)
Adjusted Segment EBDA[a]	**7,112**	**7,135**	**(23)**	**(0%)**
General and administrative and corporate charges[a]	(633)	(561)	(72)	(13%)
JV DD&A and income tax expense[a,b]	419	449	(30)	(7%)
Net income attributable to NCI[a]	(69)	(61)	(8)	(13%)
Adjusted EBITDA	**6,829**	**6,962**	**(133)**	**(2%)**
Interest, net[a]	(1,515)	(1,610)	95	6%
Cash taxes[c]	(79)	(68)	(11)	(16%)
Sustaining capital expenditures[d]	(792)	(658)	(134)	(20%)
Other items[e]	2	(29)	31	107%
DCF	**$ 4,445**	**$ 4,597**	**$ (152)**	**(3%)**

Steady segment earnings with economic recovery tempered by known re-contracting exposure & impact from disciplined investment approach in CO_2 segment

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.

c) Includes cash taxes from JVs of $67 million and $62 million in 2021 and 2020, respectively.

d) Includes sustaining capital expenditures from JVs of $119 million and $114 million in 2021 and 2020, respectively.

e) Includes non-cash pension expense and non-cash compensation associated with our restricted stock program.

2021B Capital Expenditures

$ in millions

Sustaining Capital	2021 Budget	2020 Actual	Change
Natural Gas Pipelines	$ 424	$ 341	$ 83
Products Pipelines	79	79	(0)
Terminals	251	207	44
CO_2	14	9	5
Corporate / other	24	22	2
Total sustaining capital expenditures[a]	**$ 792**	**$ 658**	**$ 134**

Discretionary Capital	2021 Budget	2020 Actual	Change
Natural Gas Pipelines[b]	$ 519	$ 1,253	$ (734)
Products Pipelines[b]	30	61	(31)
Terminals	94	214	(120)
CO_2 - Source & Transport	0	3	(3)
CO_2 - Oil & Gas	151	162	(11)
Corporate/Other	(0)	(1)	1
Total discretionary capital	**794**	**1,692**	**(898)**
Total sustaining capital expenditures[a]	792	658	134
JV sustaining capital expenditures	(119)	(114)	(5)
Contributions to unconsolidated JVs and acquisitions	(114)	(550)	436
Decrease in capital accruals and other	-	21	(21)
Capital expenditures (GAAP)	**$ 1,353**	**$ 1,707**	**$ (354)**

Meaningfully moderated capital budget
Majority still focused on natural gas assets

Note: Before Certain Items.
a) Includes sustaining capital expenditures from JVs of $119 million and $114 million in 2021 and 2020, respectively.
b) 2021 budget includes $62 million JV expansion spending, net of partner contributions for consolidated JVs, and $52 million JV debt maturities.

2021B DCF Self-Funding

in millions

	2021 Budget	2020 Actual	Change $	Change %
DCF	$ 4,445	$ 4,597	$ (152)	(3%)
Discretionary capital	(794)	(1,692)	898	53%
Declared dividends	(2,461)	(2,390)	(71)	(3%)
Share repurchases[(a)]	-	(50)	50	100%
DCF self funding	**$ 1,190**	**$ 465**	**$ 725**	**156%**

Significant excess cash flow creates additional opportunities to create shareholder value

a) No share repurchases budgeted for 2021, but have up to $450 million available for opportunistic repurchases.

2021B Cash Flow from Operations (CFFO) & Free Cash Flow (FCF)

$ in millions

	2021 Budget	2020 Actual	Change $	Change %
Net income attributable to Kinder Morgan, Inc. (GAAP)	**2,109**	**$ 119**	**$ 1,990**	**NM**
Net income attributable to noncontrolling interests	69	61	8	13%
DD&A and amortization of excess cost of equity investments	2,223	2,304	(81)	(4%)
Deferred income taxes	567	345	222	64%
Earnings from equity investments	(742)	(776)	34	4%
Distribution of equity investment earnings[(a)]	731	633	98	15%
Working Capital and other items[(b)]	(361)	1,864	(2,225)	(119%)
CFFO (GAAP)	**4,596**	**4,550**	**46**	**1%**
Capital expenditures (GAAP)	(1,353)	(1,707)	354	21%
FCF	**3,243**	**2,843**	**400**	**14%**
Dividends paid	(2,444)	(2,362)	(82)	(3%)
FCF after dividends	**$ 799**	**$ 481**	**$ 318**	**66%**

Significant excess cash flow creates additional opportunities to create shareholder value

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Excludes distributions from equity investment in excess of cumulative earnings, $245 million and $154 million in 2021 and 2020, respectively. These are included in Cash Flows Used In Investing Activities on our Consolidated Statements of Cash Flows.

b) Includes 2020 non-cash impairments of $1,000 million, $950 million, and $21 million associated with our Natural Gas Pipelines Non-regulated, CO2, and Products Pipelines reporting units, respectively.

2021B Sources & Uses[a]

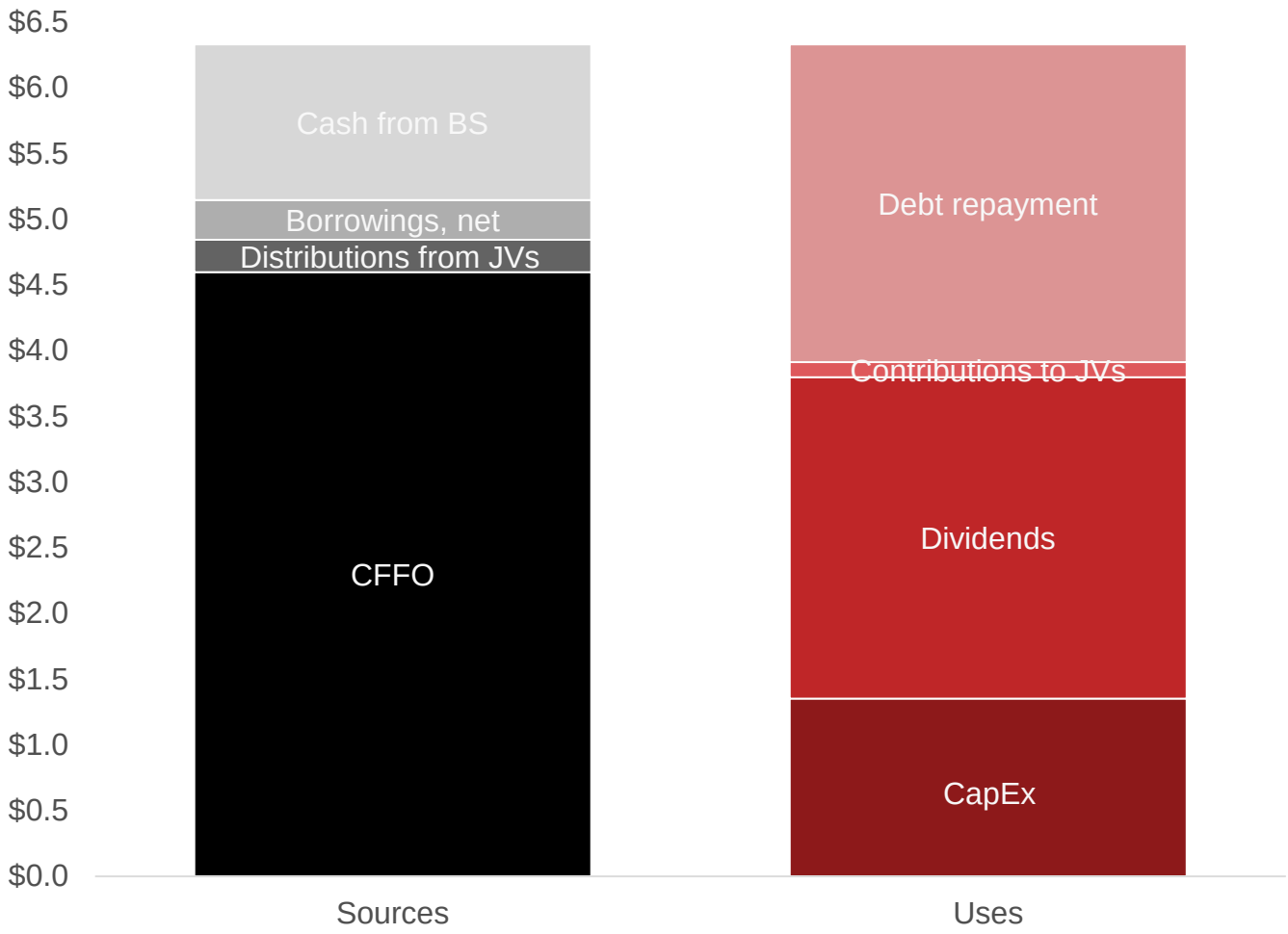
$ in millions

Sources	2021 Budget
CFFO	$ 4,596
Cash balance as of 12/31/2020	1,184
Revolver Borrowing/Debt Issuances	302
Distributions from equity investments in CFFI[b]	245
Total sources	**$ 6,327**

Uses	2021 Budget
Dividends paid	$ 2,444
Debt maturities	2,416
Capital expenditures (GAAP)	1,353
Contributions to investments	114
Total uses	**$ 6,327**

Using operating cash flow to fully fund dividend payment & all capital expenditures

SOURCES & USES $ in billions



Note: See Non-GAAP Financial Measures and Reconciliations.

a) High level view of sources and uses, and will vary depending on discretionary use of free cash flow.

b) Reflects distributions from equity investments in excess of cumulative earnings.

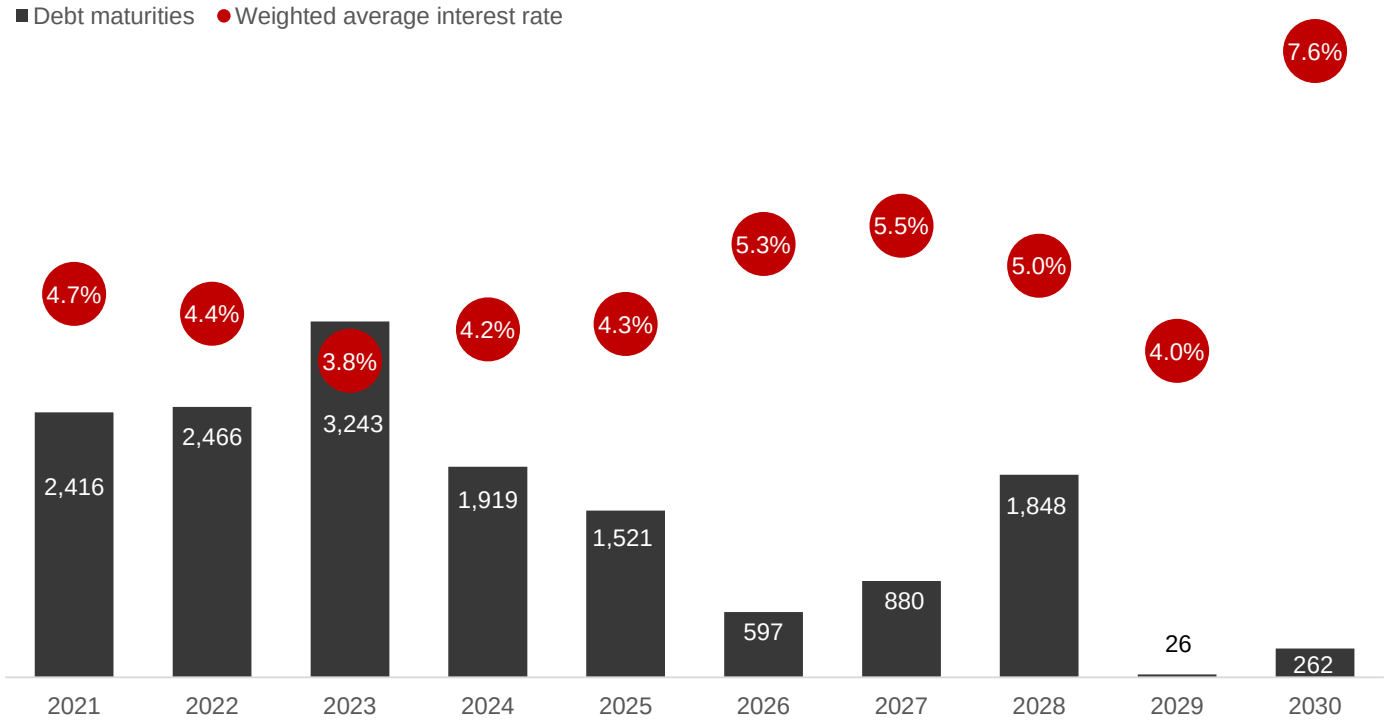
Leverage & Liquidity[a]

$ in millions

	2021 Budget
Net Debt (Year End)	$ 31,244
Adjusted EBITDA	$ 6,829
Net Debt[b] to Adjusted EBITDA	**4.6x**

KMI revolver capacity	**12/31/2020**
Committed revolving credit facility[c]	$ 4,000
CP / Revolver borrowing	-
Letters of credit	(82)
Available capacity	**$ 3,918**

KMI LONG-TERM DEBT MATURITIES[d]



Financial flexibility with ~$4 billion of capacity on our credit facility & manageable future debt maturities

Note: See Non-GAAP Financial Measures and Reconciliations.

a) Debt of KMI and its consolidated subsidiaries excluding fair value adjustments.

b) Debt as defined in footnote (a), net of cash and foreign exchange impact on Euro denominated debt.

c) KMI corporate revolver facility has a November 2023 maturity.

d) 10-year maturity schedule of KMI's consolidated long-term debt, excluding fair value adjustments, $221 million preferred securities, $170 million non-cash foreign exchange impact on Euro denominated debt, and immaterial capital lease and other obligations

2021B Quarterly Profile

$ in millions, except per share

Adjusted Segment EBDA	Q1	Q2	Q3	Q4	Total
2021 Budget	26%	24%	24%	26%	$ 7,112
2020 Actual	26%	23%	25%	26%	$ 7,135

Adjusted EBITDA					
2021 Budget	26%	24%	24%	26%	$ 6,829
2020 Actual	26%	23%	25%	26%	$ 6,962

Distributable Cash Flow (DCF)					
2021 Budget	28%	23%	23%	26%	$ 4,445
2020 Actual	27%	22%	24%	27%	$ 4,597

Adjusted EPS					
2021 Budget	26%	23%	23%	28%	$ 0.92
2020 Actual	26%	19%	24%	31%	$ 0.88

Note: See Non-GAAP Financial Measures and Reconciliations.

2021B Cash Tax Calculation Detail

$ in millions

	2021 Budget
Adjusted Segment EBDA	$ 7,112
Net income attributable to NCI	(69)
JV earnings from C corps	(350)
JV distributions from C corps (net of 65% dividend received deduction)	138
JV book DD&A (pass-through entities)	143
General and administrative and corporate charges	(633)
Interest, net	(1,515)
Book capex items expensed for tax purposes	(397)
Tax DD&A	(5,331)
Other items	(143)
Taxable loss	**$ (1,045)**

KMI U.S. federal cash taxes	$ -
Other cash taxes[(a)]	79
Total cash taxes	**$ 79**

Note: All items shown before certain items. See Non-GAAP Financial Measures and Reconciliations.

a) Includes cash taxes for our share of unconsolidated C corp JVs (Citrus, Plantation and NGPL), Texas margin tax and other state income taxes.

2021 Budget Sensitivities

Limited overall commodity exposure

2021B assumptions	Change	Potential Impact to Adjusted EBITDA & DCF (full year)				
		Natural Gas	Products	Terminals	CO_2	Total
Natural gas G&P volumes 2.864 bcfd	+/- 5%	$28 million				$28 million
Refined products volumes (gasoline, diesel & jet fuel) 1,676 mbbld for Products segment	+/- 5%		$36 million	$9 million		$45 million
Crude oil & condensate pipeline volumes 577 mbbld net	+/- 5%		$15 million			$15 million
Crude oil production volumes 41 mbbld gross (29 mbbld net)	+/- 5% in gross volumes				$22 million	$22 million
CO_2 sales 693 mmcfd gross (331 mmcfd net)	+/- 50 in gross volumes				$7 million	$7 million
$43/bbl WTI crude oil price	+/- $1/bbl WTI	$0.6 million	$1.5 million		$1.3 million	$3.4 million
$3.00/Dth natural gas price	+/- $0.10/Dth	$0.4 million[a]				$0.4 million[a]
$0.055/gallon ethane frac spread	+/- $0.01/gallon	$3.5 million[b]				$3.5 million[b]
NGL / crude oil price ratio 60% in Natural Gas segment & 41% in CO_2 segment	+/- 1% price ratio	$0.3 million			$1 million	$1.3 million
		Potential Impact to DCF (balance of year)				
LIBOR interest rates 0.15% 1-month / 0.21% 3-month	+/-10-bp change in LIBOR					$3.6 million[c]

Note: These sensitivities are general estimates of anticipated impacts on our business segments & overall business of changes relative to our assumptions; the impact of actual changes may vary significantly depending on the affected asset, product & contract. See Non-GAAP Financial Measures & Reconciliations at the end of this presentation for additional information.

a) Assumes constant ethane frac spread vs. natural gas prices
b) An unfavorable impact can be limited by reducing ethane equity volumes through operational changes & contractual elections.
c) As of 12/31/2020, ~16% of the principal amount of our debt balance was subject to variable interest rates – either as short- or long-term variable rate debt obligations or as fixed-rate debt converted to variable rates through the use of interest rate swaps. As of 12/31/2020, we had ~$7.6 billion of fixed-to-floating interest rate swaps on our long-term debt. We have fixed the LIBOR component on $2.5 billion of our floating rate swaps through the end of 2021.

Financial Highlights

Enhanced financial strength despite significant demand & price disruptions

	2020	2021 BUDGET
Weathering market disruptions	EBITDA down only 8% from budget despite significant demand & price disruptions	Demand disruptions remain, but expect financial recovery
Dividend growth	Declared dividends +5%	Expect declared dividends +3%
Net debt reduction	~$990 million	~$800 million[a]
Increase in Free Cash Flow[b]	$365 million	$400 million
	Improved cost of capital by issuing debt at all-time low coupon rates (2% 10-yr & 3.25% 30-yr)	Cash flow capacity for up to $450mm in stock buybacks

a) Could vary depending on discretionary use of Free Cash Flow.
b) CFFO less capital expenditures (GAAP). See Non-GAAP Financial Measures & Reconciliations.

Q&A

Natural Gas

Segment Presentation

Natural Gas Segment Overview

Connecting key natural gas resources with major demand centers

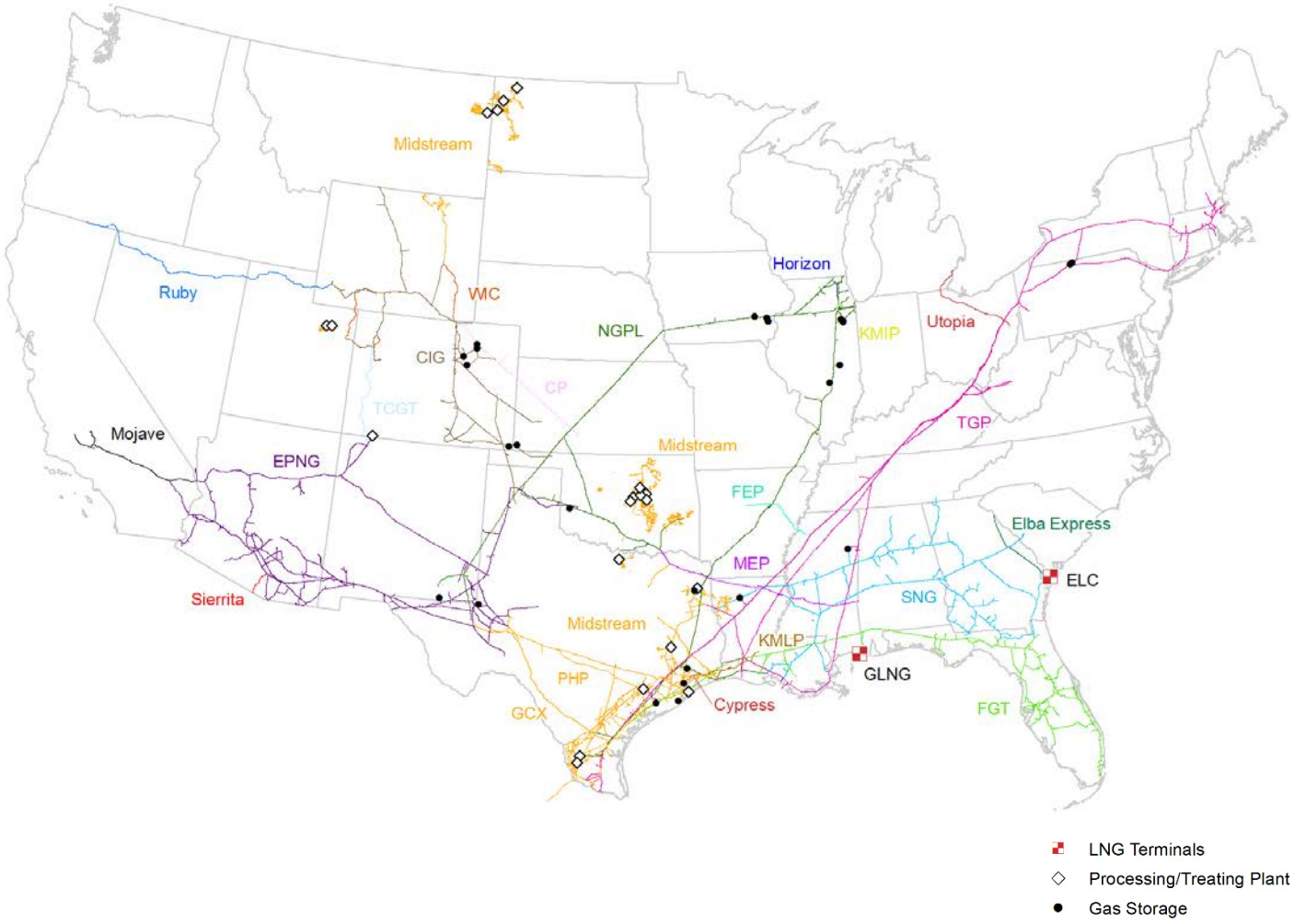
ASSET SUMMARY		
Natural gas pipelines:	~70,000	miles
NGL pipelines:	~1,200	miles
Natural gas transported (U.S. consumption & exports)		~40%
Working gas storage capacity:	659	bcf

2021 budgeted EBDA: $4.4 billion

Contributes ~60% of segment earnings & backlog

Connects effectively all major supply areas to key demand centers across the U.S.

Attractive expansion opportunities from significant existing footprint



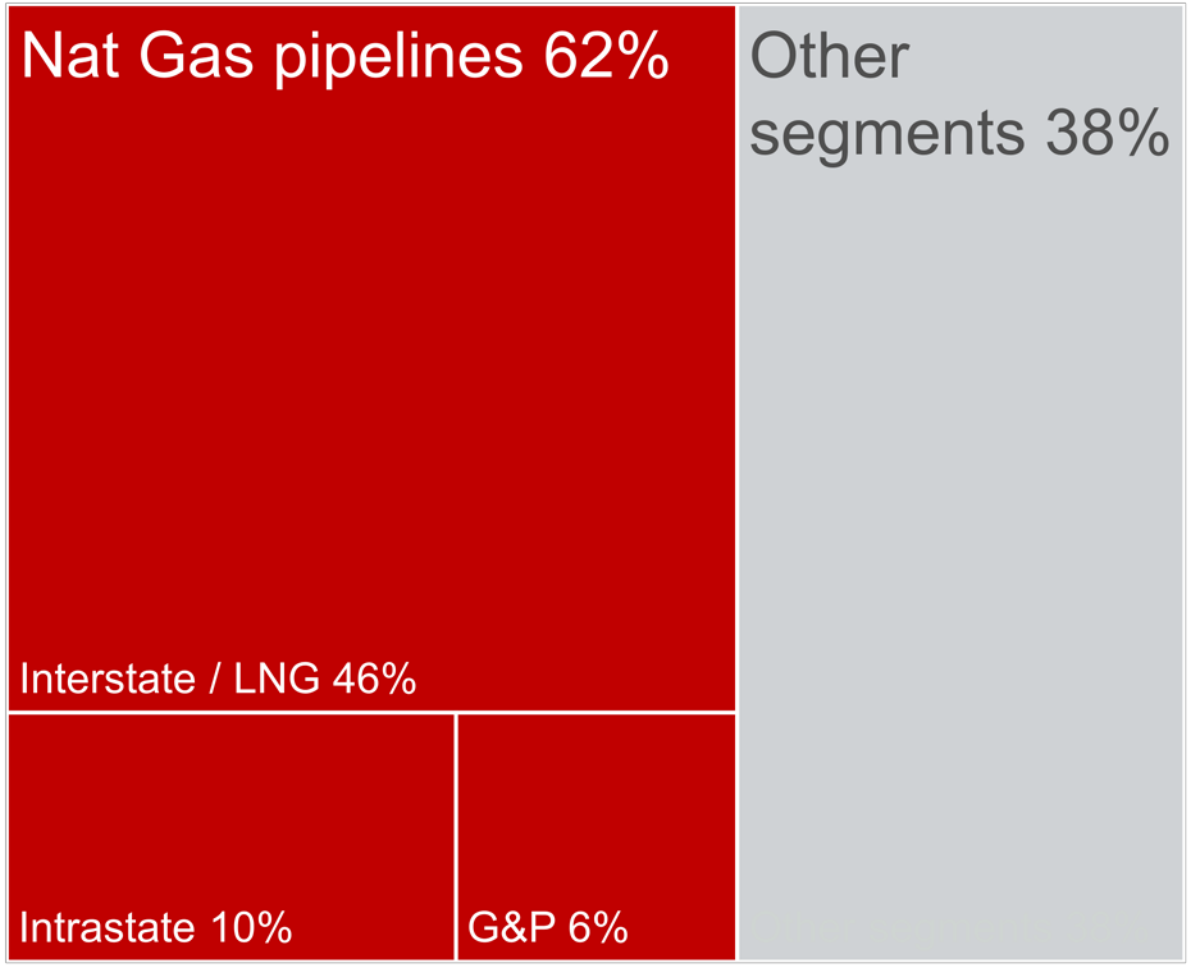
Note: 2021 budgeted EBDA & earnings contribution based on 2021 budgeted Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Natural Gas Segment is Predominantly Transport Pipelines

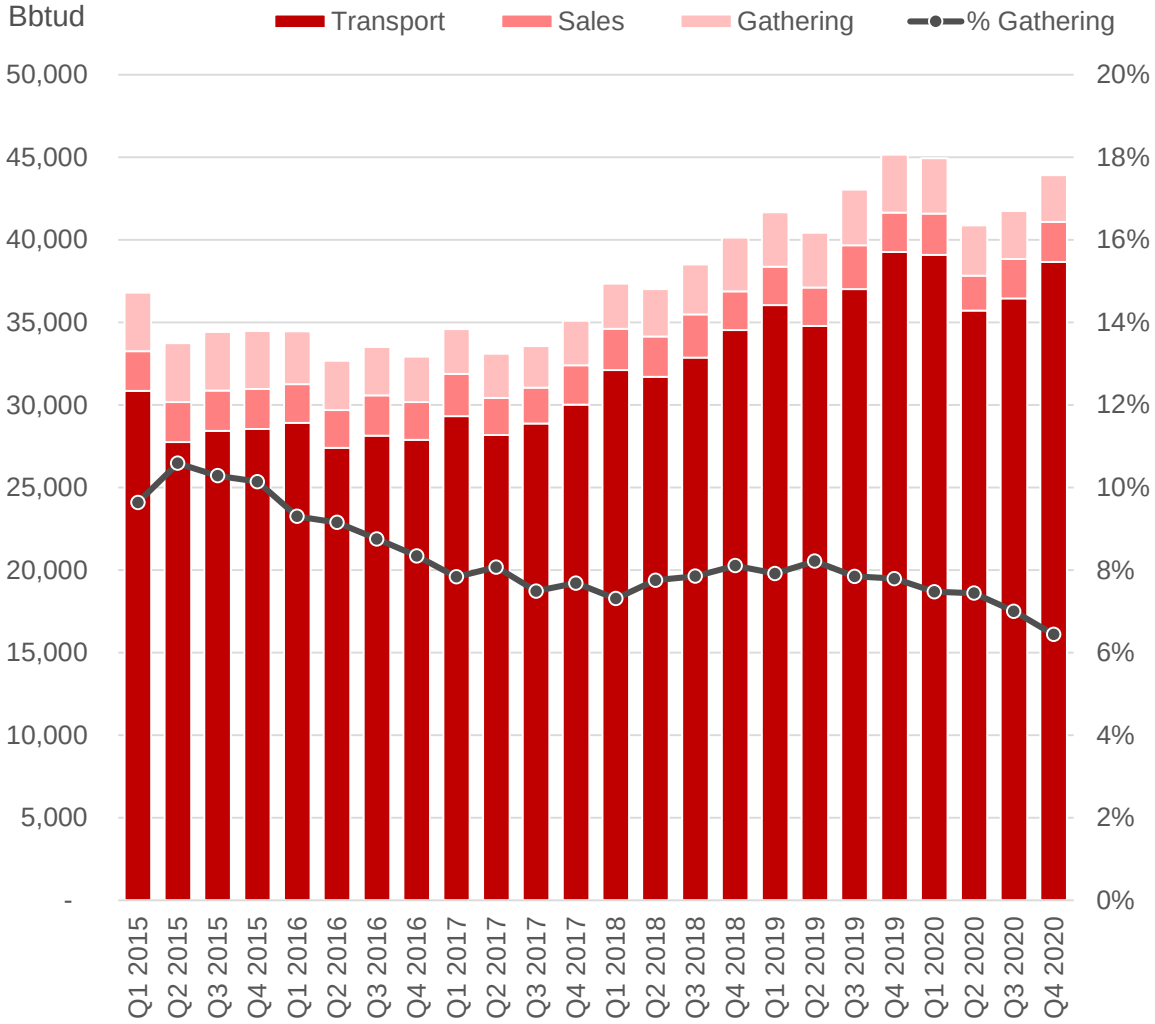
Over 80% take-or-pay | Fee-based gathering & processing assets focused in the Bakken, Eagle Ford & Haynesville

BUSINESS MIX

based on Adjusted Segment EBDA per 2021 Budget



NATURAL GAS SEGMENT VOLUMES



Note: % take-or-pay based on budgeted Adjusted Segment EBDA per 2021 company budget. See Non-GAAP Financial Measures & Reconciliations.

Natural Gas: Interstate Pipelines

Key statistics

		Ownership	Miles	Capacity (bcfd)	Storage (bcf)	Avg. Remaining Contract Term (yrs)	Effective Date of Next Rate Case	Rate Moratorium Through Date
100% KMI-owned:								
TGP	Tennessee Gas Pipeline	100%	11,760	12.1	80	8.4 / 3.6[a]	NA	10/31/2022
EPNG	El Paso Natural Gas + Mojave	100%	10,680	6.4	44	6.3	NA	12/31/2021
CIG	Colorado Interstate Gas	100%	4,300	6.0	38	4.8 / 5.6[a]	4/1/2022	9/30/2020
WIC	Wyoming Interstate	100%	850	3.6	–	3.3	4/1/2022	12/31/2020
KMLP	Kinder Morgan Louisiana Pipeline	100%	135	3.0	–	13.9	NA	NA
CP	Cheyenne Plains	100%	410	1.2	–	1.6	NA	NA
TCGT	TransColorado	100%	310	0.8	–	0.4	NA	NA
EEC	Elba Express	100%	200	1.1	–	16.4	NA	NA
Jointly-owned (asset stats shown at 100%):								
NGPL	Natural Gas Pipeline Co. of America	50%	9,100	7.6	288	5.1 / 2.9[a]	NA	6/30/2022
SNG	Southern Natural Gas	50%	6,930	4.4	66	4.8 / 1.7[a]	9/1/2024	8/31/2021
FGT	Florida Gas Transmission	50%	5,360	3.9	–	8.4	2/1/2021	1/31/2021
FEP	Fayetteville Express	50%	185	2.0	–	1.9	NA	NA
MEP	Midcontinent Express	50%	510	1.8	–	1.7	NA	NA
	Ruby	50%[b]	680	1.5	–	2.2	NA	NA
	Sierrita	35%	60	0.5	–	18.8	NA	NA
Storage & LNG (asset stats shown at 100%):								
	Keystone Gas Storage	100%	15	0.4	6	2.4	NA	
SLNG	Southern LNG Co. (Elba Island)	100%	–	1.8	12	11.8	NA	
GLNG	Gulf LNG	50%	5	1.5	7	10.8	NA	
ELC	Elba Liquefaction Company	51%	–	0.35	–	19.7	NA	
YGS	Young Gas Storage (CIG)	47.5%			6	4.4	NA	

a) Transport / Storage.
b) Reflects third party ownership of a 50% preferred interest.

Gathering & Processing Assets Across Multiple Key Basins

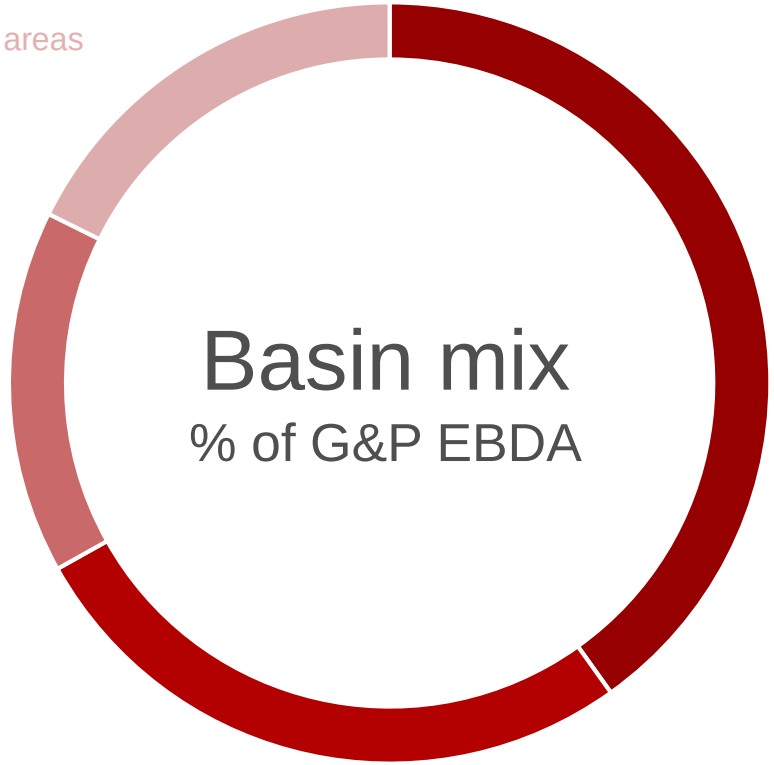
Represents ~7% of KMI EBDA with ~6% in Natural Gas & ~1% in Products (primarily Bakken)

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

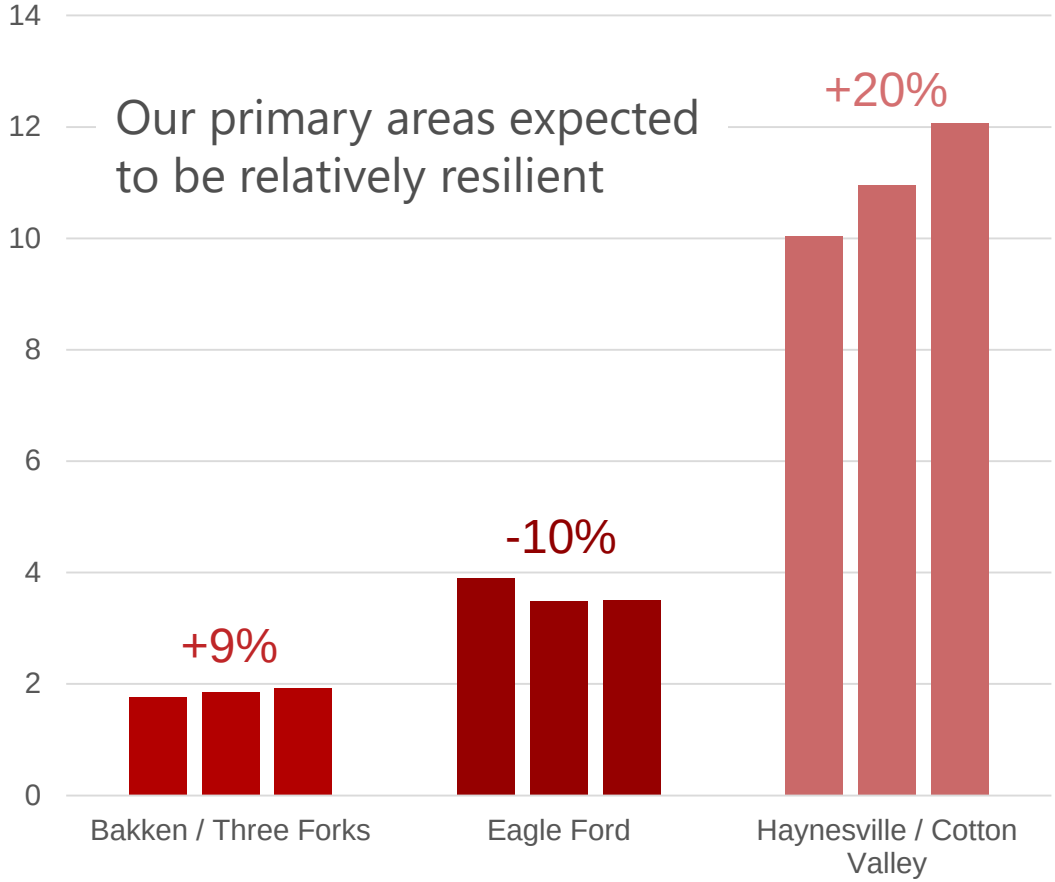
~13% Haynesville
KinderHawk assets with proximity to Gulf Coast industrial & LNG

~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 – 2022



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 (December 2020).

Natural Gas: Intrastate, G&P and NGL Assets

Key statistics

	Ownership	Miles	Capacity	Avg. Remaining Contract Term (yrs)	Storage	Treating	Processing
			(bcfd)		(bcf)	(GPM)	(bcfd)
100% KMI-owned natural gas pipelines:							
KMTP / Tejas	100%	5,920	8.3	5.7	132	1,680	0.5
Copano - gas	100%	6,120	4.8	2.5		2,600	1.1
KinderHawk Gathering	100%	520	2.4	life of lease		2,960	
Mier-Monterrey	100%	90	0.7	7.3			
North Texas Pipeline	100%	80	0.3	12.6			
Hiland (Williston Basin) - gas	100%	2,180	0.6	13.9		80	0.3
Camino Real Gathering - gas	100%	70	0.2	1.8			
Altamont Gathering	100%	1,510	0.1	2.1			0.1
Jointly-owned natural gas pipelines (asset stats shown at 100%):							
Eagle Hawk Gathering - gas	25%	530	1.2	life of lease			
Gulf Coast Express	34%	530	2.0	8.7			
Permian Highway Pipeline	27%	430	2.1	10.0			
Red Cedar Gathering	49%	900	0.3	3.8		4,600	
Treating - Leased Units	100%	Plants in service: 45 Amine / 39 Mechancial Refrigeration Units / 16 Dew Point					
			(mbbld)		(mbbl)		
100% KMI-owned liquids pipelines:							
Copano - liquid	100%	430	115	4.1			
Jointly-owned liquids pipelines (asset stats shown at 100%):							
Cypress (FERC Regulated)	50%	100	56	0.3			
Utopia (FERC Regulated)	50%	270	50	18.0			
Eagle Hawk Gathering- condensate	25%	400	220	life of lease	60		

Note: KMTP/Tejas average remaining contract term is 5.7 years for transport & 4.5 years including term sales portfolio.

Long-Term Growth Drivers: Natural Gas Segment

Opportunity for our unique last-mile pipeline connectivity, capitalizing on industry trends

Exports	— LNG exports: pipeline & storage infrastructure supporting existing & new LNG development — Exports to Mexico: well-positioned to serve growing demand as critical infrastructure is built within Mexico
Storage (659 Bcf), linepack & additional capacity to support increasingly variable demand	— LNG export interruptions (e.g., due to weather, cargo cancellations, maintenance) — Complement variable renewable generation with responsive gas deliverability — Support daily & seasonal variability in exports to Mexico, where minimal storage exists — Balancing services to meet peak demand periods in summer & winter — Develop creative new services to address increasing variability in most demand sectors
Petrochemical & other industrial demand along the Gulf Coast	— Strategic pipeline footprint & storage to serve growing demand — Established deliverability & unique high pressure capability into major market centers
Leverage existing ~70,000 mile pipeline network	— Investment in facility modifications provides bi-directional flow opportunities — Extensions off of existing network to connect growing supply to end-use markets — Repurpose assets to serve new markets and/or maximize value - move higher margin products through pipes — Tailor premium non-ratable services to leverage operational flexibility — Brownfield solutions in increasingly challenging market for new construction — Provide transportation & storage for Responsibly Sourced Gas (RSG)
End-user / LDC demand growth	— Regional power generation opportunities, baseload growth, peaking & deliverability — Unique last-mile connectivity to LDC, electric generation & industrial markets
Well-positioned to move potential fuels of the future	— Renewable Natural Gas (RNG) — Hydrogen

Leading the Way Out of the Permian

Excellent execution in face of global pandemic & substantial opposition

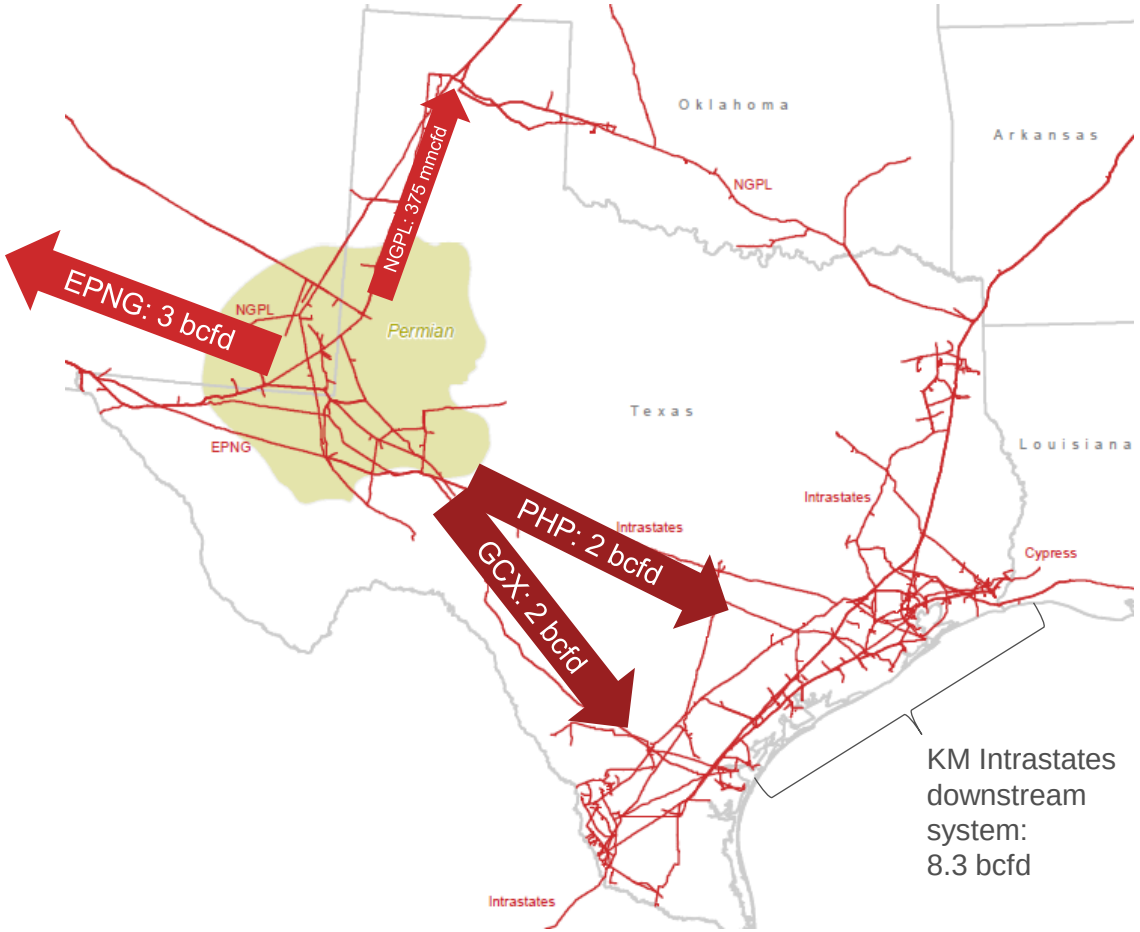
Leveraging existing footprint into new takeaway capacity

- Reaches across Texas & the Desert Southwest, connecting into major demand markets
- Our advantaged network offers broad end-market optionality with deliverability to Houston markets (power, petrochemical), substantial LNG export capacity & Mexico

Invested over $250 million across existing Texas Intrastates pipeline networks

- Supporting distribution of significant incremental volumes
- Increased capacity by ~1.4 bcfd
- Key to delivering Permian volumes into the U.S. Gulf Coast & Mexico markets

	Gulf Coast Express (GCX)	Permian Highway Pipeline (PHP)
Mainline:	450 miles of 42” pipeline	430 miles of 42” pipeline
Endpoint:	Near Agua Dulce	Near Katy
KM ownership:	34%	26.7%
Capacity:	2.0 bcfd	2.1 bcfd
Capital (100%):	$1.75 billion	~$2.2 billion
In-Service:	September 2019	January 1, 2021
Min. contract term:	10 years	10 years



Providing unparalleled takeaway capacity from the Permian basin to the Gulf Coast & Desert SW markets

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

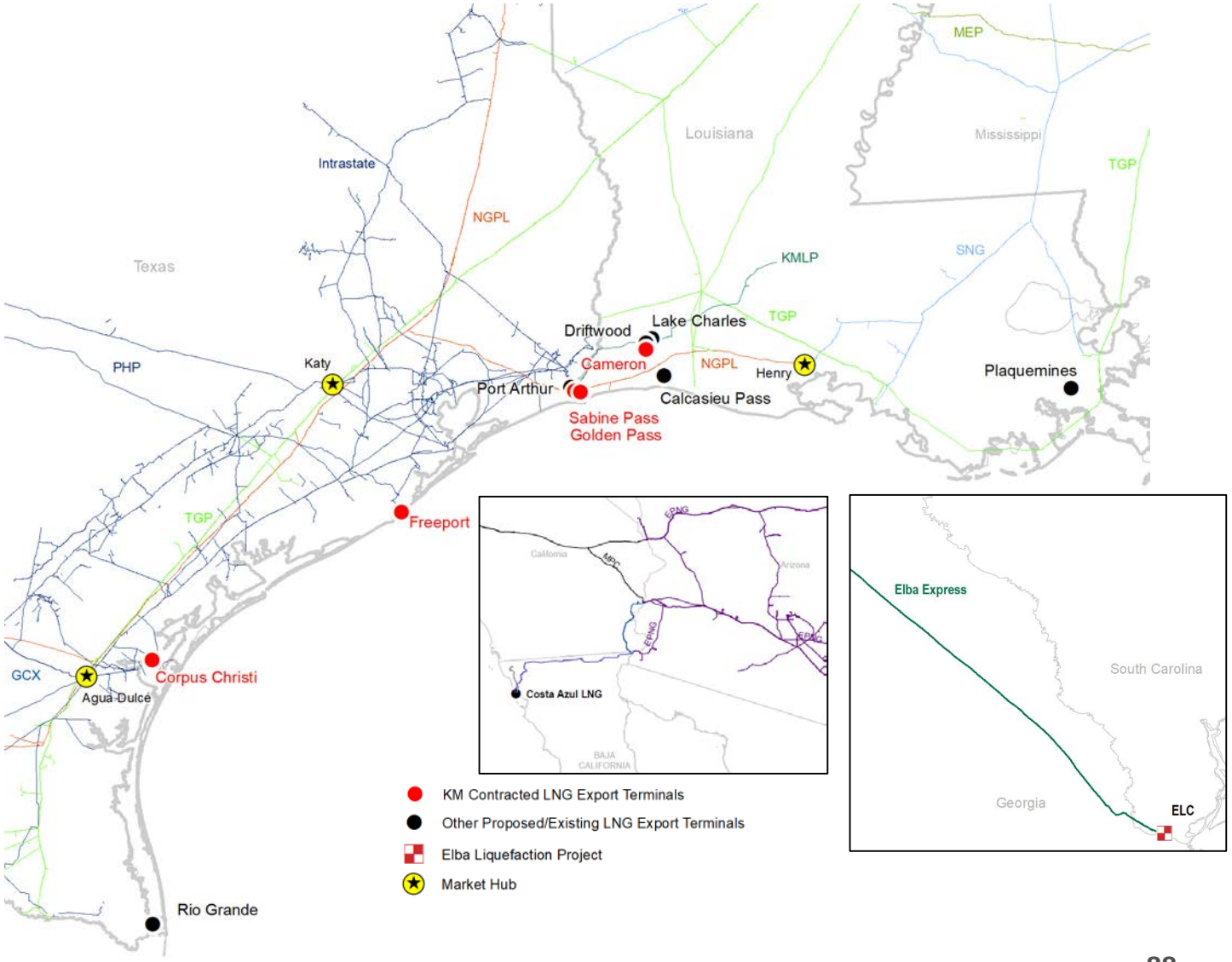
Premier deliverability

659 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
~ 4.4 bcfd	1.7 bcfd	17 years	2-4 bcfd

Also deliver ~1 bcfd of producer / marketer supply



Key Market: Exports to Mexico

Expect to maintain market share of growing Mexico market | ~57%[a] in 2020

Extensive footprint offers diverse supply options to multiple Mexico interconnections – 12 direct & 4 indirect

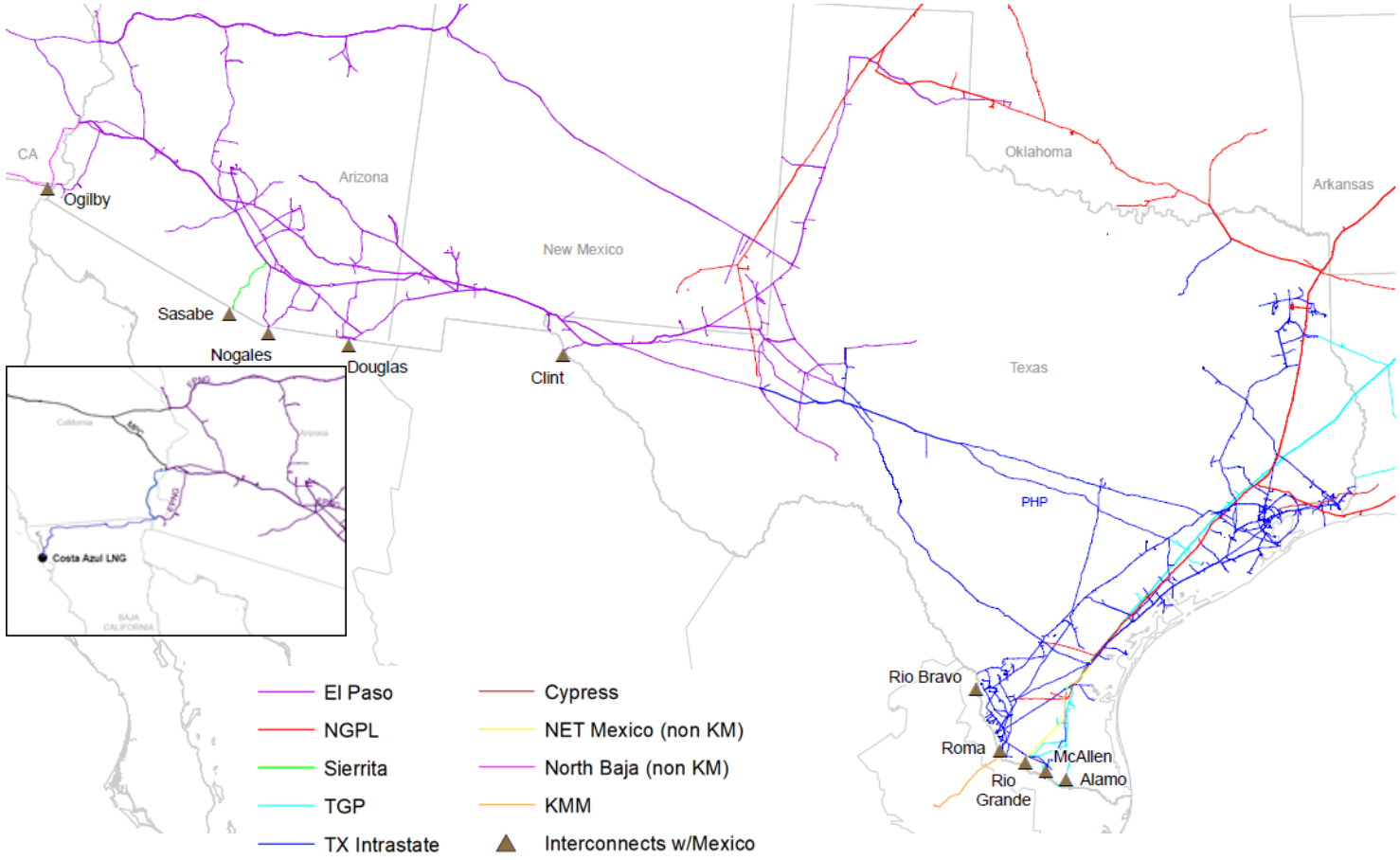
U.S. natural gas exports to Mexico are expected to grow by 22%, or ~1.2 bcfd, to 6.6 bcfd by 2025[b]

~1.6 bcfd of capacity put in service for ~$600 million since 2014

Opportunities remain:

- Expansions of existing assets (including Monterrey)
- Storage & hub services near the border
- West Coast Costa Azul LNG adds incremental demand to the Desert Southwest
  - Global gas pricing will influence regional pricing & volatility & may incentivize additional infrastructure investment (capacity & storage)
  - Costa Azul Phase II will require additional infrastructure

2020 volumes delivered	Contracted capacity	Average remaining contract term
~3.3 bcfd	~3.9 bcfd	~11 years



Multiple pipelines across our network supply growing Mexican demand with attractive opportunities in the future

Note: KM projects / long-term commitments to Mexico detail available in Natural Gas segment presentation.

a) Sources: U.S. Energy Information Administration - U.S. Natural Gas Exports, Velocity Suite – pipeline nomination data, Nueva Era Pipeline Informational Postings, Sur de Texas-Tuxpan Pipeline Informational Postings & KM Analysis.

b) Source: WoodMackenzie, North America Gas Markets Long-Term Outlook, Fall 2020.

Supporting Increasing Variable Demand

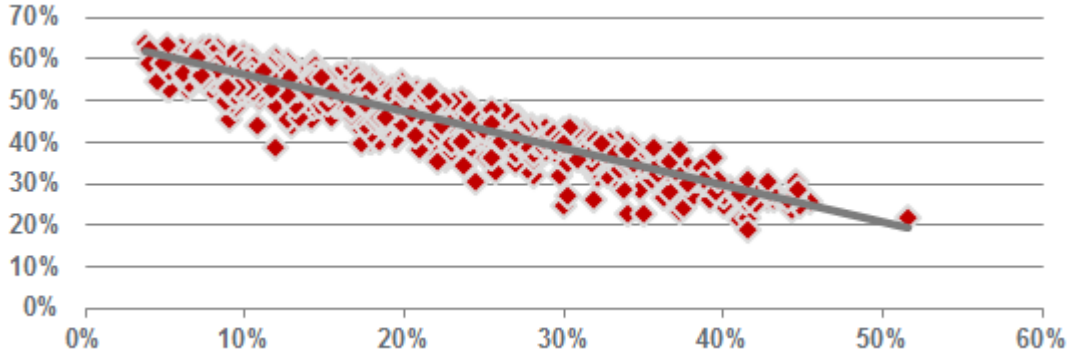
Opportunities for short notice, high deliverability services & gas storage

Renewable generation

- Non-dispatchable, intermittent wind & solar generation requires dispatchable natural gas-fired generation to ramp up during periods of low generation from wind & solar
- Necessary to provide variable amounts of gas pipeline capacity on-demand or with limited notice
- Increases necessity of pipeline linepack & market area storage

DAILY ERCOT GENERATION[a] Dec 2018 – Oct 2020

as % of demand: natural gas (y-axis) & wind (x-axis)



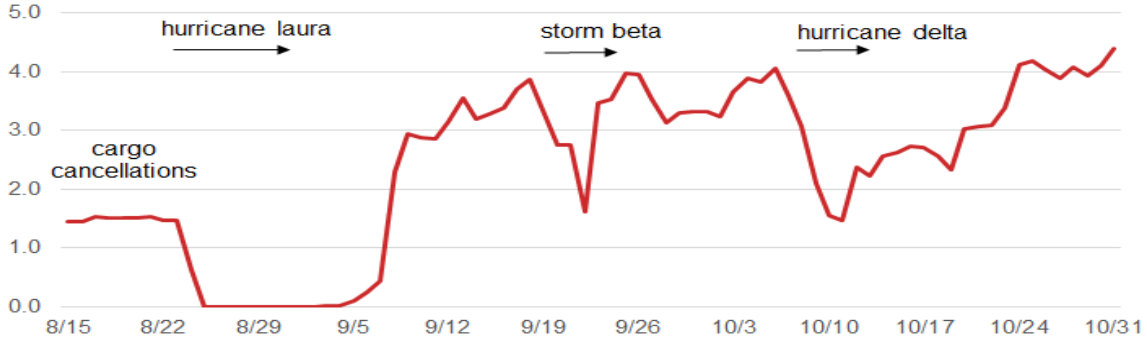
Tailor services to provide required deliverability, including allocating capacity to provide additional no notice or hourly services

Export demand

- Interruptions to LNG exports due to cargo cancellations, weather or other outages[b]
- Provide sufficient injection capability & storage capacity driven by sudden LNG interruptions
- Minimal existing storage capability in Mexico

TOTAL SABINE PASS DELIVERIES[b]

bcfd (y-axis) & Aug 15 – Oct 31, 2020 (x-axis)



Provide responsive pipeline & storage services with our multiple large diameter pipelines & 659 bcf of working gas storage in production & market areas

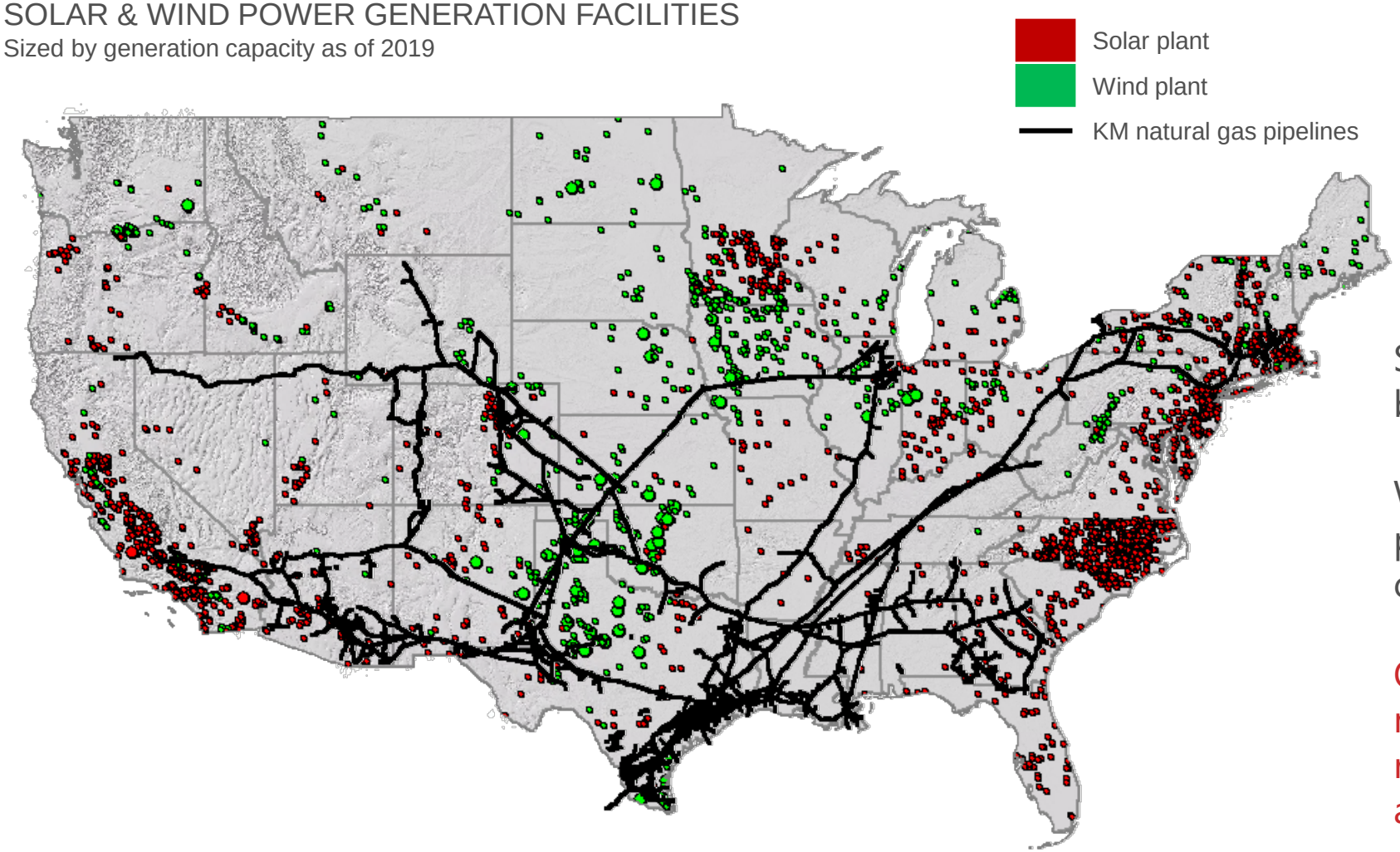
a) U.S. Energy Information Administration – U.S. Electric System Operating Data.
b) Velocity Suite/KM Data.

We Serve Regions with Meaningful Renewable Power Today

Our tailored deliverability services better support the needs of flexible grids in these areas

SOLAR & WIND POWER GENERATION FACILITIES

Sized by generation capacity as of 2019



Solar power generation tends to be concentrated along the coasts

Wind power generation most prominent in the interior of the country

Our extensive natural gas pipeline network spans both of these regions & supports customers who are firming renewable power assets

Source: Hitachi ABB Velocity Suite Monthly Plant Generation.

Renewables Require Hourly Flexibility & Associated Non-Ratable Services

KINDER MORGAN

Currently serving this dynamic in Western markets – trend developing in Central & Eastern markets

Our service offerings reflect dedicated use of infrastructure required to meet market demand (ratable & non-ratable services)

Coupled with ratable service, underutilized assets & horizontal linepack can be used to support non-ratable services

Ratable Service	Supply basin exports to various interconnects (Interstate/Intrastate pipelines, industrial, LNG, Mexico, etc.)
Non-Ratable Service	On-system local distribution companies (LDCs) & utility electric generators with variable hourly demand **Examples:** High population load centers (i.e. Phoenix) without Market Area Storage (EPNG) *(High renewable penetration)* Colorado Front Range with Market Area Storage (CIG) *(Large unpredictable temperature swings & renewable penetration)*

Non-ratable services are priced higher than ratable service, reflecting associated infrastructure use

- Pipe, storage & compression provide for hourly peak demand & duration, pressure guarantees, no-notice takes
- Service structures & associated rate design/pricing efficiently ration deployed capital over time
- Economic & physical incentives for adequate contracting / nominations
- Colorado Front Range & Desert Southwest market area facilities are currently fully dedicated & backed by long-term contracts

As renewable penetration grows along our footprint, underutilized assets & services are being investigated / developed to address the non-ratable opportunities in those markets

Opportunities from Energy in Transition

Multiple strategies to participate with our substantial natural gas assets

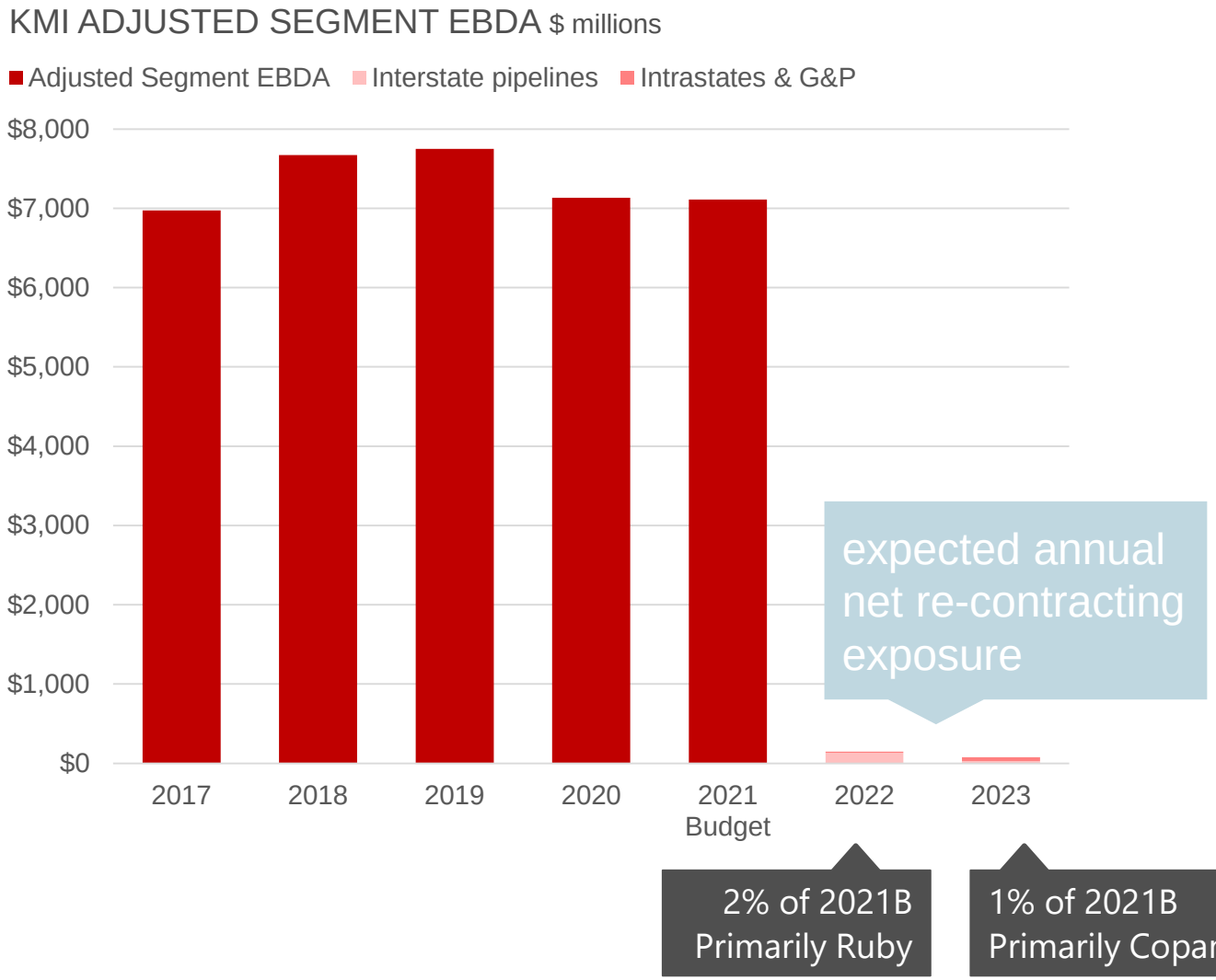
Near-Term Strategies	Opportunities	Next-Steps
Position base business to further enable renewable penetration	• Monetize deliverability & unutilized ratable capacity	• Identifying regions & specific pipeline corridors that may benefit from specific service enhancements
Energy storage to firm intermittent renewable infrastructure	• High-turn storage, look to repurpose for H2 or low-carbon fuels	• Engaging current utility customers to assess their need for & propensity to support an energy storage project
Incorporate clean power around our operations	• Reduce power cost (peak shave) & lower emissions	• Analyzing our assets & operations for potential peak shaving opportunities • Engaging potential clean power providers

Emerging & longer-term opportunities:

Responsibly sourced gas (RSG), renewable natural gas (RNG), power transmission & ROWs, hydrogen

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)

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.

Projects Placed Into Service During 2020

New natural gas projects expected to generate $297 million of annual EBITDA

Asset	Project	In-service date: 2020 (Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec)	Capacity (mDthd)	KM share ($mm) Capital	KM share ($mm) EBITDA
Texas Intrastates	Permian Highway		2100	$652	
	Crossover II		1400	$257	
	Dayton Storage Loop Line		275	$58	
	Intrastate well / market connects		570	$30	
	TGP Storage Expansion Project		12 Bcf	$28	
ELC	Elba Liquefaction - 7 units and ancillary facilities		250	$244	
EPNG	South Mainline Expansion		471	$134	
	XTO / Matador Permian Expansion		415	$58	
Gathering / Other	Williston Basin (Hiland Gas)		Various	$56	
	Altamont		Various	$15	
	Other		Various	$13	
NGPL	Sabine Pass Compression		400	$34	
	Lockridge Lateral Extension		500	$26	
	NIPSCO		40	$10	
Sieritta	Sieritta Gas Pipeline Expansion		230	$16	
FGT	Various Expansions		87	$6	
CIG	5C Ft Lupton / High Five		167	$5	
SNG	Ranburne Meter Station		4	$1	
Total Natural Gas Pipeline Segment:				**$1,644**	**$297**

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation. Permian Highway in-service date shown as of initial commissioning.

Project Backlog

Natural Gas

Asset	Project	KM share ($mm) Capital	KM share ($mm) EBITDA	Capacity (mDthd)	In-service Date	Project Status
TGP	East 300 Upgrade	$246		115	11/2022	Under Development
	Line 261 Upgrade (Eversource)	$72		121	11/2021	Under Construction
	Station 321 Cooling	$10		30	11/2021	Under Development
KMLP	Acadiana (Cheniere SP Train 6)	$145		945	2Q2022	Under Construction
NGPL	GC Southbound Phase II (Cheniere C.C.)	$101		300	2Q2021	Under Construction
FGT	Seminole Electric Project	$48		136	4/2022	FERC Certificate received 3/19/2020
	Big Bend	$18		29	8/2023	Preparing FERC 7(c) Application
	Galveston County Project	$9		107	2/2021	Under Development
EPNG	Sempra LNG Vail	$23		95	4/2022	Under Development
CIG	Carlsbad South Expansion	$23		159	1/2021	Under Construction
	Black Hills Elkhart	$0		1	6/2021	Under Development
SNG	Dalton	$3		5	10/2021	Preparing prior notice filing
Total Interstate		$699	$140			
Texas Intrastate	AP Texas City Expansion	$34		75	1Q2023	Construction ongoing
	Bob West Loop (Monterrey)	$22		35	2Q2021	Construction ongoing
	Intrastate - well / market connects	$15		Various	1Q - 4Q2021	Supply / Market connects to transmission systems
Gathering / Other	Roosevelt Gas Exp. Projs.	$46		200	4Q2022	Extension for dedicated future development area
	HP Gathering Slug Catcher	$21		17	2Q2021	Under Construction
	Other system expansion and well connects	$68		Various	2021	Expansions / extensions of existing gathering systems
Total Midstream		$206	$51			
Total Natural Gas Pipeline Segment		$904	$191			

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation.

LNG Contract Overview

Contracted capacity (online / to come) & Elba Liquefaction

KM Asset	Contracted capacity (mDthd)	KM share ($mm) Capital	KM share ($mm) EBITDA	Remaining contract term
TGP	1,250	$281		
KMLP	1,545	$278		
NGPL	1,975	$223		
EPNG	95	$23		
Intrastate	740	$370		
Elba Express	436	$100		
Transport subtotal	6,041	$1,275		17 years
Elba liquefaction	350 mmcfd	$1,264		20 years
Total		$2,539	$368	

~$2.5 billion of capital projects

Note: EBITDA is a non-GAAP financial measure. See Non-GAAP Financial Measures & Reconciliations. EBITDA represents first full calendar year of operation (KM share).

Products

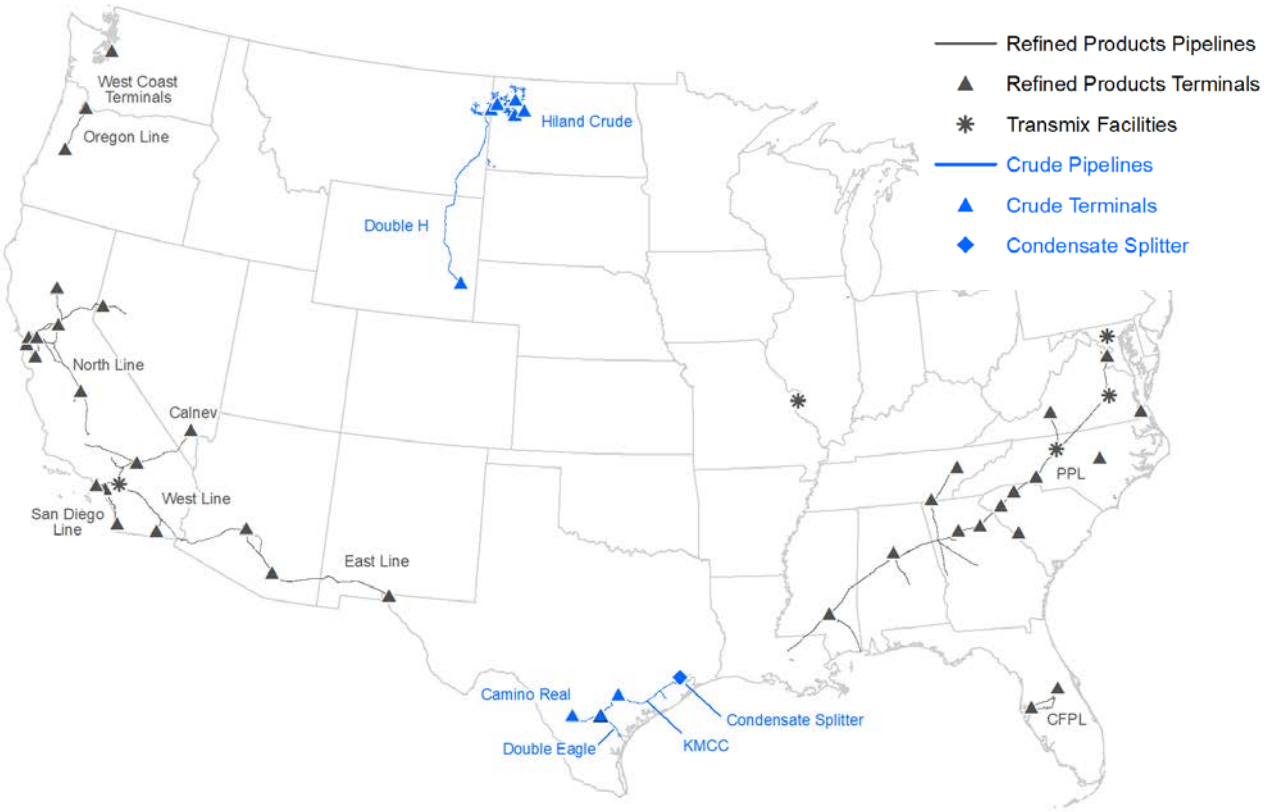
Segment Presentation

Products Segment Overview

Strategic footprint with significant cash flow generation

ASSET SUMMARY

Pipelines:	~9,500	miles
2021 budgeted throughput[a]	~2.3	mmbbld
Terminals:	65	terminals
Terminals tank capacity	~39	mmbbls
Pipeline tank capacity	~16	mmbbls
Condensate processing capacity	100	mbbld
Transmix	5	facilities



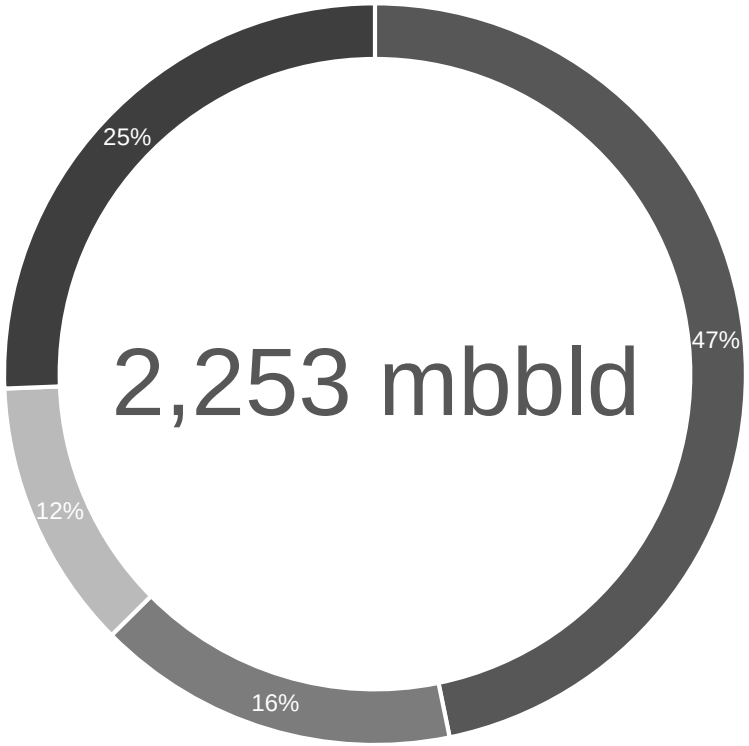
2021 budgeted EBDA of ~$1.2 billion
+13% over 2020

Note: 2021 budgeted EBDA based on Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
a) Volumes include SFPP, CALNEV, Central Florida, PPL (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering.

Products Segment Volume Mix

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

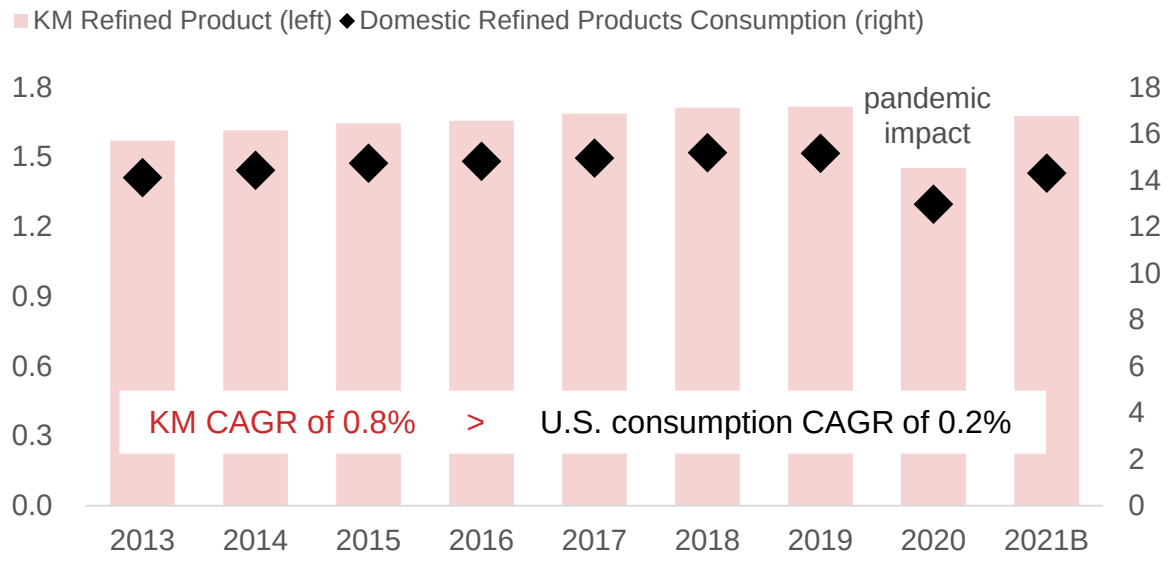
a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida, PPL (KM share), KMCC, Camino Real, Double Eagle (KM share), Double H & Hiland Crude Gathering; Gasoline volumes include ethanol.
b) Southeast Region Assets include Central Florida & PPL (KM share); West Region includes SFPP & CALNEV. Texas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

Refined Products Pipes Historically A Steady Contributor

Fee-based with stable volumes over the long-term

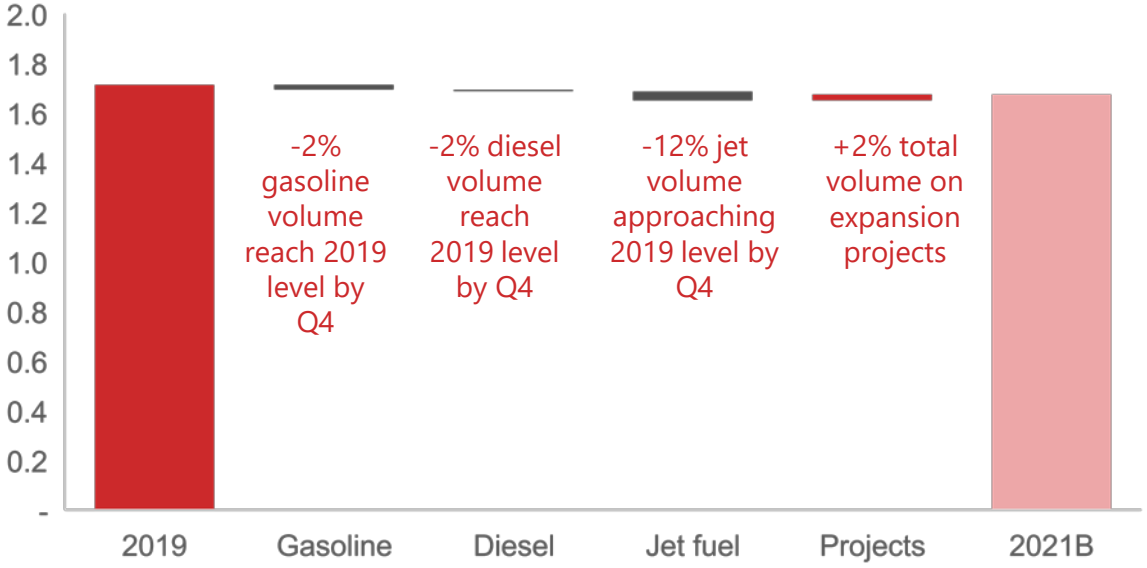
REFINED PRODUCTS VOLUMES[a]

mmbbld



2021 BUDGETED VOLUMES VS 2019 ACTUAL VOLUMES

mmbbld



Unmatched connectivity between major refining centers & key demand markets

- West Coast: SFPP & CALNEV deliver product from major refining centers in San Francisco, Los Angeles & El Paso, as well as marine terminals along the West Coast, to cities throughout California, Arizona, Nevada, Washington & Oregon
- Southeast: PPL sourced by PADD 3 refineries, the most competitive refining center in the world, delivers to population centers from Mississippi to Virginia

Refined product demand continues to recover throughout 2021

- Strong economy continues to support diesel demand
- Jet fuel rebound in 2021 coincides with vaccine roll-out

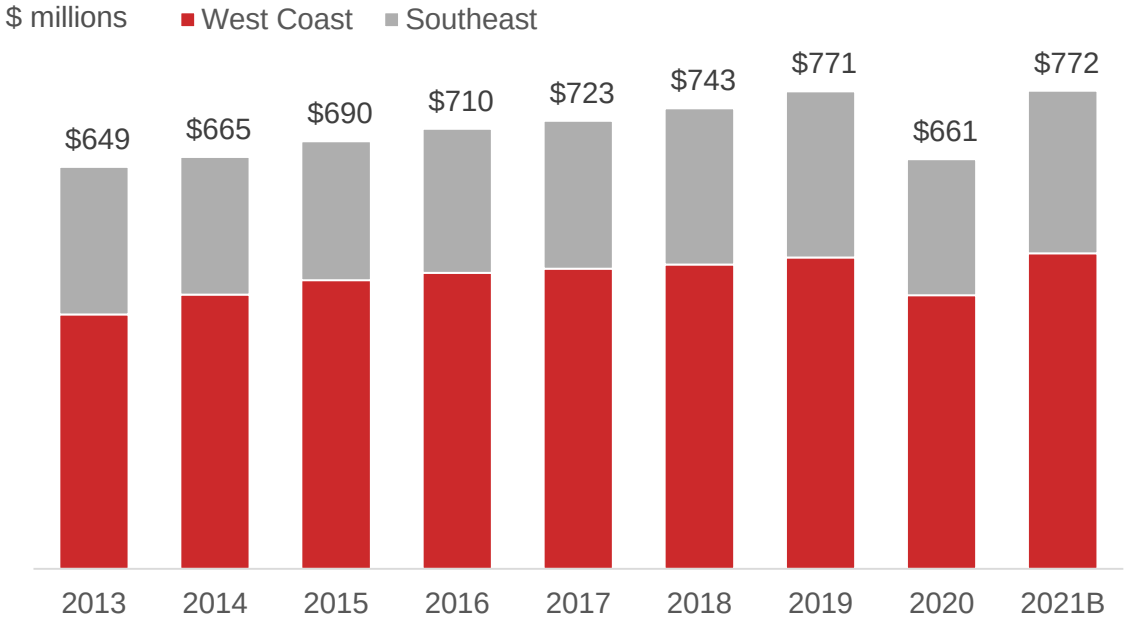
Note: Volume CAGR calculated from 2013 through 2021B.

a) Kinder Morgan volumes include SFPP, CALNEV, Central Florida & PPL (KM share). U.S. consumption volumes per EIA, Short-term Energy Outlook Table 4a, December 2020.

Refined Products Assets Generate Stable Cash Flows

Earnings recovery & growth opportunities

REFINED PRODUCTS EBDA BY REGION[a]



KM EBDA CAGR of

2.2%

KM volume CAGR of

> 0.8%

- Renewable fuels provide opportunity to sell incremental services
- Vast geography provides opportunity for tuck-in acquisitions
- Volume growth translates to earnings growth
- FERC indexing provides long-term growth driver averaging 2.7% Jul 2013 – Jun 2021[b]

Note: See Non-GAAP Financial Measures & Reconciliations. CAGR calculated from 2013 through 2021B.

a) Contributions to Products Pipelines Adjusted Segment EBDA are from SFPP, CALNEV, West Coast Terminals, Central Florida, Transmix, PPL (KM share) & Southeast Terminals.

b) FERC index published on ferc.gov. Average rate from July 1, 2013 to June 30, 2021.

West Coast Renewable Fuels Projects

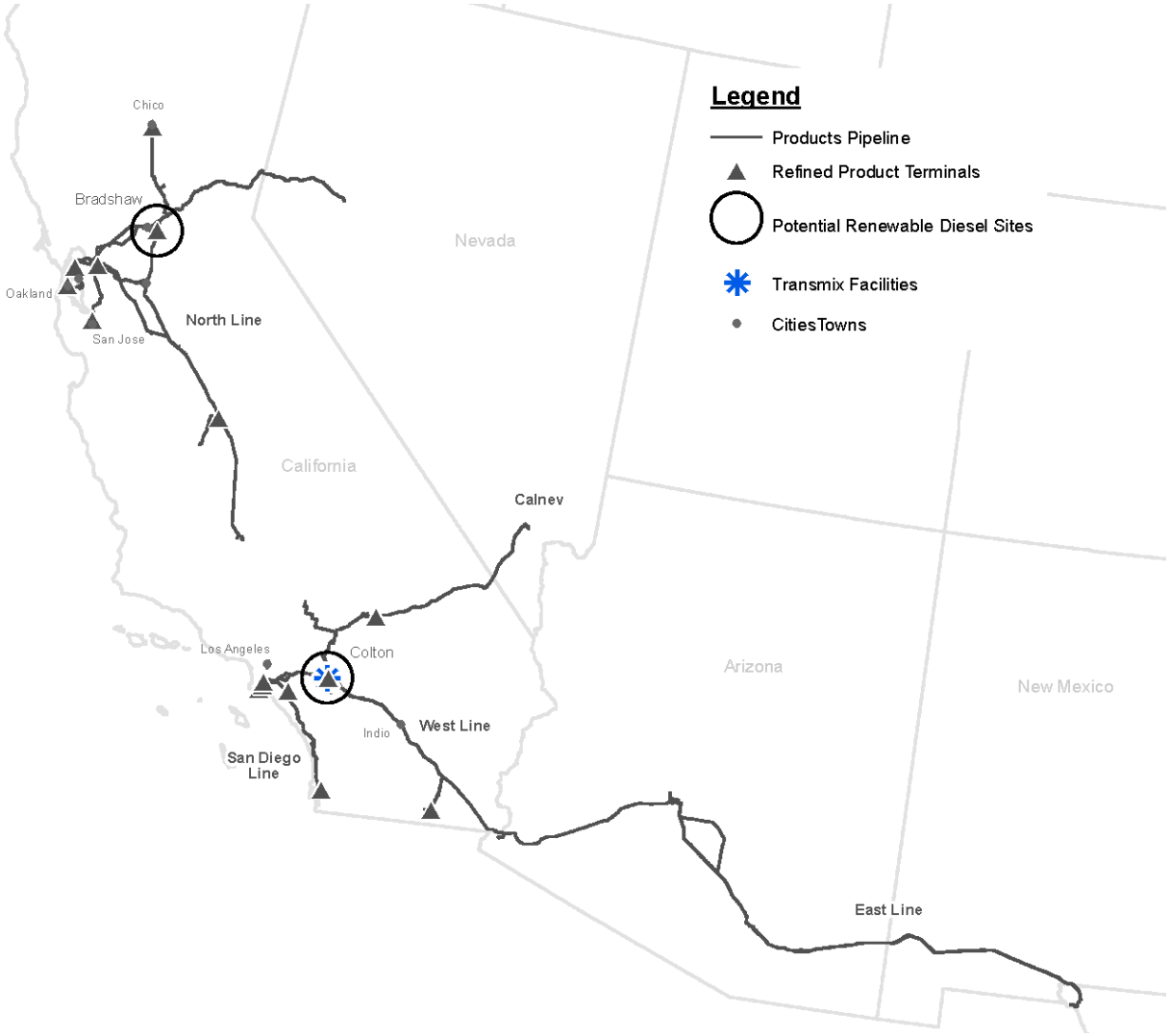
Developing infrastructure to secure renewable fuels

Market drivers

- Renewable Diesel (RD) has been driven by California subsidies
  - RIN credits
  - Low Carbon Fuel Standard (LCFS) credits
  - Blender's Tax Credit
  - Currently averaging approximately $3.00/gal for total credits (RIN+LCFS+ Blender's tax credits)
- State goals to reduce emissions
  - CARB has 2030 goal to reduce 1990-level GHG emissions by 40%
  - Oregon's Clean Transportation Fuel Standards program has aggressive goals for reducing carbon emissions

Potential project highlights

- Construction of new RD hubs in both Northern & Southern California
  - Approximately $90 million discretionary capex for all locations
  - Rail in renewable diesel / biodiesel
  - Segregated storage for renewable products
  - Opportunities to blend RD with both biodiesel & CARB diesel over the truck rack – providing increased high-value optionality to customers
  - Each hub location currently scoped for 20 mbbld renewable capacity with further expansion opportunities available
- Serving the entire California diesel market
- Biodiesel blend capabilities will increase from existing 5% limit to 20%

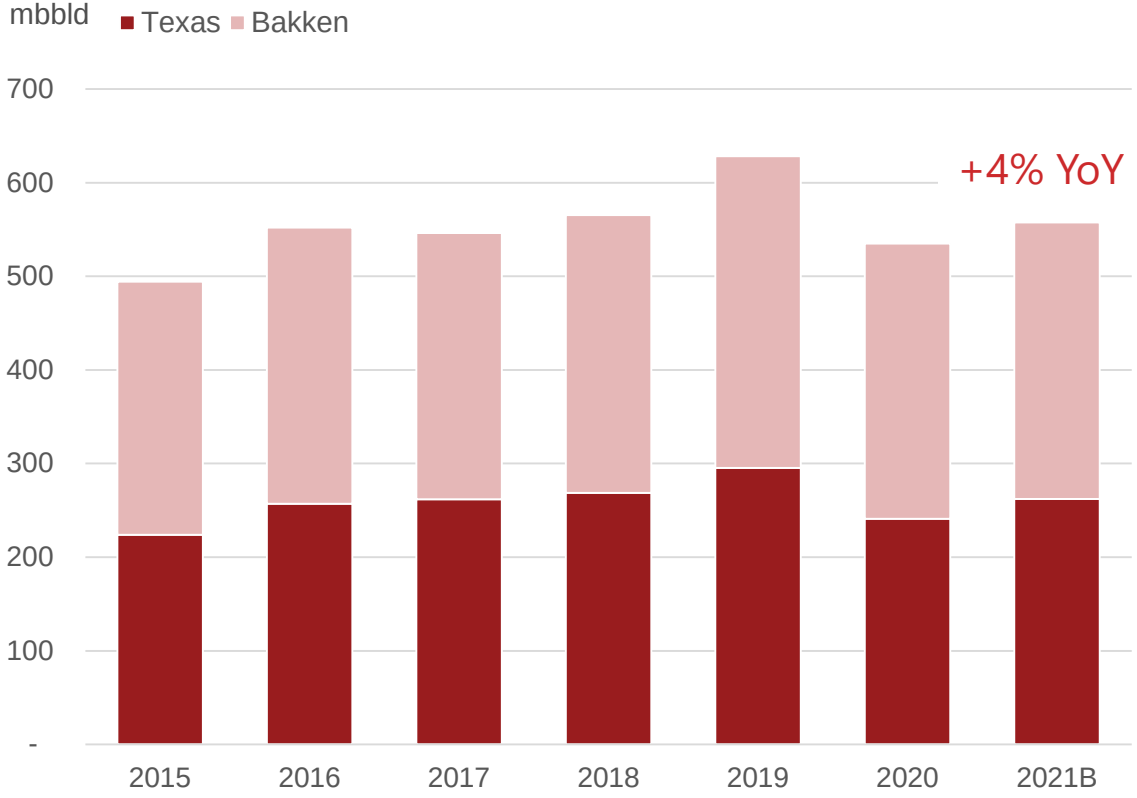


Note: RIN = Renewable Identification Numbers. CARB = California Air Resources Board.

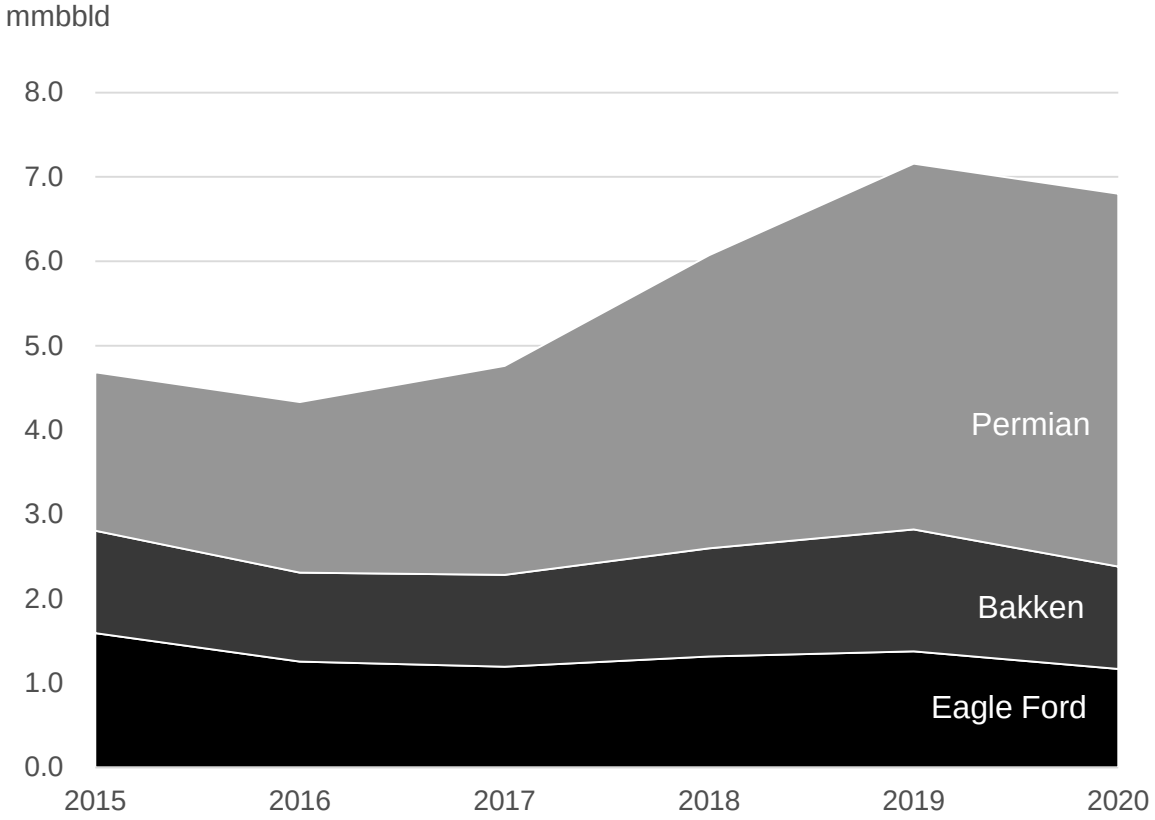
Volume Across Crude Assets Outpace Production

Maximizing throughput in difficult markets: marketing affiliates on KMCC & Double H utilize available capacity on spot basis

THROUGHPUT VOLUMES BY CRUDE PIPELINE



CRUDE OIL PRODUCTION[a]



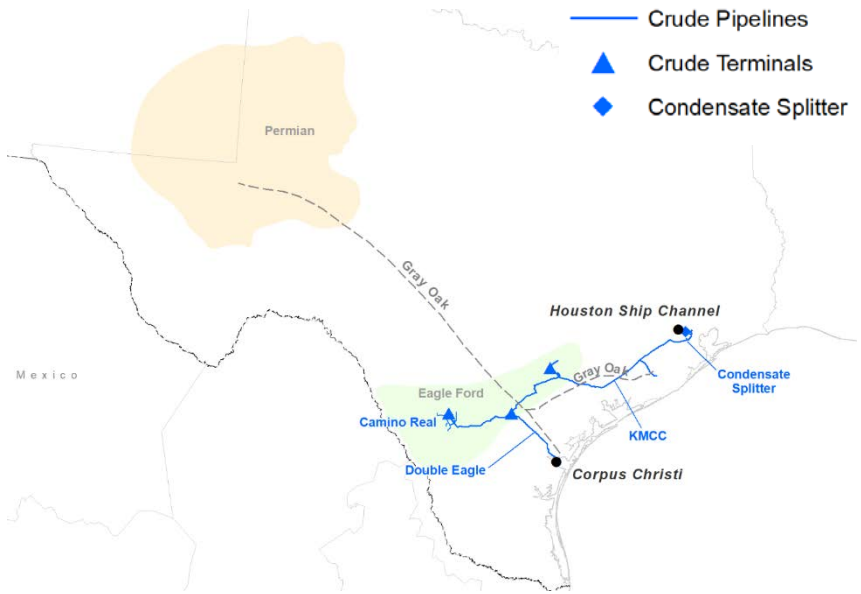
Our Texas & Bakken pipelines CAGR of 1.6% > Eagle Ford & Bakken production CAGR of (3.2)%

Note: Bakken volumes include Hiland Crude Gathering & Double H Pipelines. Texas volumes include Double Eagle Pipeline & KMCC. CAGR calculated from 2015 through 2020.

a) Source: U.S. EIA Drilling Productivity Report, December 2020.

Texas & Bakken Crude Oil Assets

Strategically positioned in Eagle Ford & Bakken



- Texas crude assets offer connectivity to the Corpus Christi & Houston Ship Channel markets
  - Flexibility to reach domestic refining capacity & export facilities
- KMCC connection & mainline expansion allow for delivering Permian Basin volumes into Houston market under joint tariff service with Gray Oak pipeline
- Condensate splitter located in the Houston Ship Channel with two processing units totaling 100 mbbld of capacity

- Hiland is one of the Bakken's premier gathering systems
  - Backed by dedications from key producers in the basin
  - Strategically positioned in core Bakken acreage
- Double H aggregates Hiland volumes for delivery into Cushing & other U.S. markets
  - Joint tariff with Pony Express provides access to Cushing

Products Segment Snapshot

Asset statistics

Crude oil assets:	Statistics	Origin	Destination
KM Crude & Condensate pipeline (KMCC)	266 miles	Eagle Ford Shale Field in South TX (Dewitt, Karnes, Gonzales Counties)	Houston Ship Channel Refining Complex
Camino Real Gathering	66 miles	South Texas, Eagle Ford shale formation	
Double Eagle pipeline (50% JV)	204 miles	Eagle Ford	Corpus Christi & KMCC
Double H pipeline	512 miles	Bakken shale in Montana & North Dakota	Guernsey, WY
Hiland (Williston Basin)	1,595 miles	Bakken / Three Forks shale formations (North Dakota / Montana)	
Condensate Splitter	Two 50 mbbld units which split condensate into its various components; located in the Houston Ship Channel		
Refined products assets:			
PPL (51% JV)	3,183 miles	Louisiana & Mississippi	From Mississippi through Virginia incl. Tennessee
SFPP Pipeline System	2,845 miles	North Line: San Fran Bay area refineries Oregon Line: Portland Marine terminals West Line: Los Angeles Basin East Line: El Paso, TX	North Line: Northern CA & NV Oregon Line: Eugene, OR West & East Lines: Arizona San Diego Line: serves major population areas in Orange County & San Diego
CALNEV Pipeline System	566 miles	Colton, CA	Las Vegas, NV
Central Florida Pipeline (CFPL)	206 miles	Tampa, FL	Orlando, FL
Southeast Terminals	25 locations ~9 mmbbls capacity	From Mississippi through Virginia incl. Tennessee	
West Coast Terminals	38 miles 8 locations ~10 mmbbls storage capacity	Seattle, Portland, San Francisco & Los Angeles area terminals	
Transmix Facilities	~0.6 mmbbls tankage capacity	Colton, CA; St Louis, MO; Greensboro, NC; Woodbine, MD; Richmond, VA	

Terminals

Segment Presentation

Terminals Segment Overview

National terminaling network connecting our customers with domestic & international markets

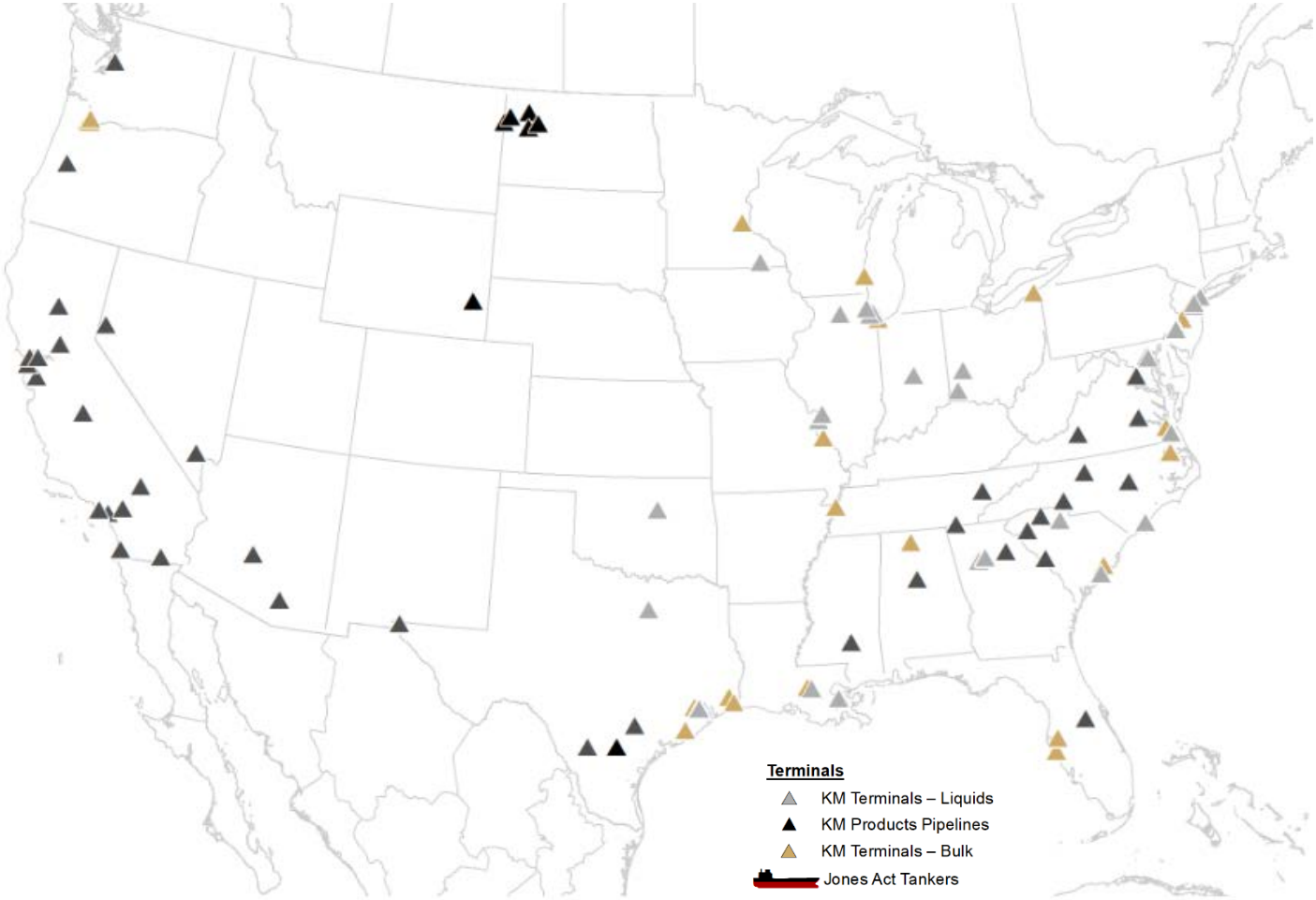
ASSET SUMMARY	# of terminals	capacity (mmbbls)
Terminals segment – Bulk	29	
Terminals segment – Liquids	50	80
Products segment	65	55
Total Terminals	144	135
Jones Act:	16 tankers	

2021 budgeted EBDA of ~$1.0 billion

Nationwide footprint focused on refined products, renewables & chemicals

Earnings driven by long-term contractual use of our assets

Infrastructure critical to our customers & their business

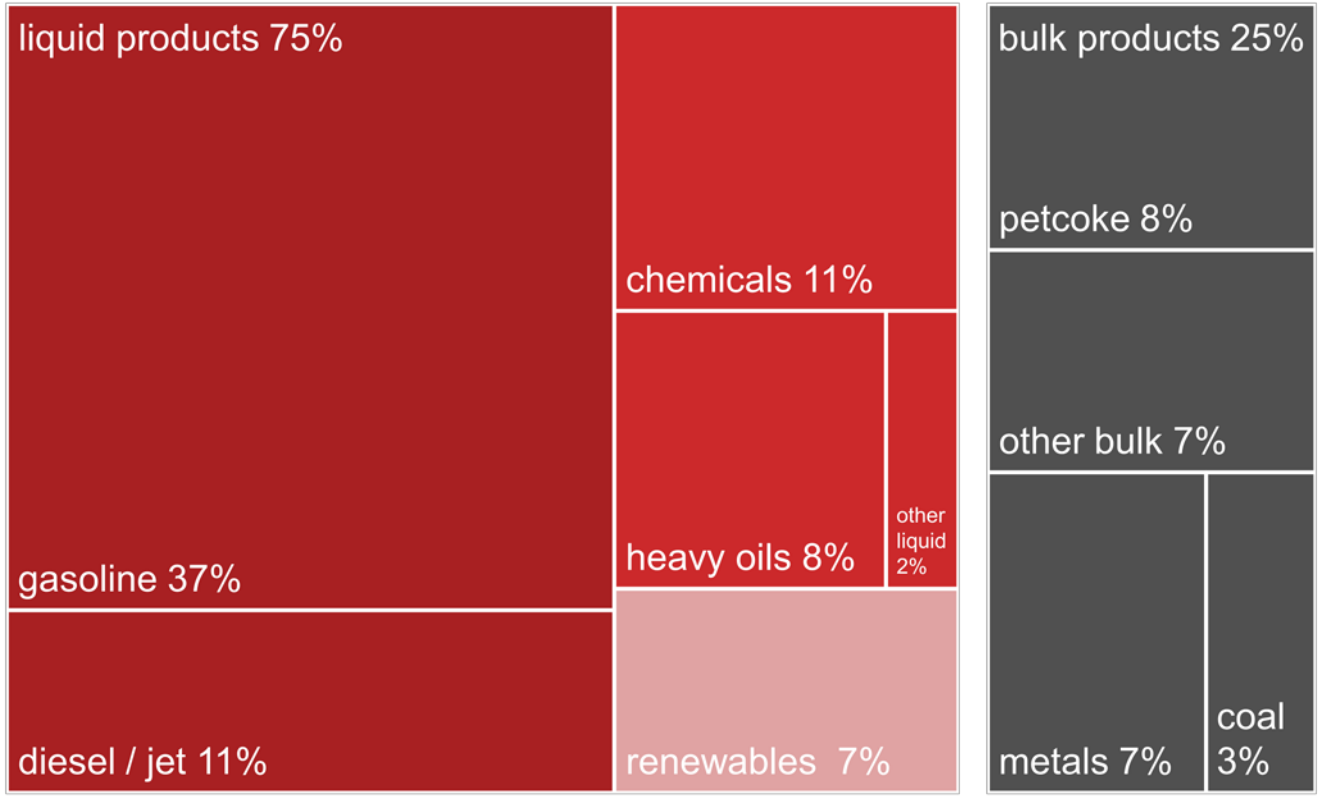


Note: 2021 budgeted EBDA based on Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Liquids-Focused Terminals with a Diverse Product Mix

Core services to the domestic refining industry

2021B REVENUE: $1.8 BILLION[a]



LIQUIDS

- Market-making industry hubs in key refining centers critical to our customers
- Complementary & synergistic with renewables & chemicals
- Jones Act tankers to meet domestic maritime demand; renewables & chemicals capable
- Unmatched service offerings & flexibility to efficiently supply domestic & international markets

BULK

- Complementary petroleum coke logistics & export terminals serving the refinery industry
- Services to domestic steel manufacturing

Partner to domestic refiners, the most competitive world-wide supply

Complementary renewables & chemicals services offering future growth

a) 2021 budgeted Terminals Segment revenues.

Terminals Segment Contract Model

Earnings driven by long-term contractual use of our assets

take-or-pay 70%

- Leased tank capacity (pre-paid monthly)
- Jones Act tanker charters (pre-paid monthly)
- Minimum volume commitments (per bbl or ton)

other fee-based 20%

- Ancillary services (e.g., vessel loading & blending)
- Based on customer use (per bbl or ton)
- Secured by customer & market needs

requirements 10%

- Ratable fee-based contracts based on customer plant production
- Refineries – petroleum coke
- Steelmaking – Nucor in-plant services

Resilient business model as proven by 2020 performance

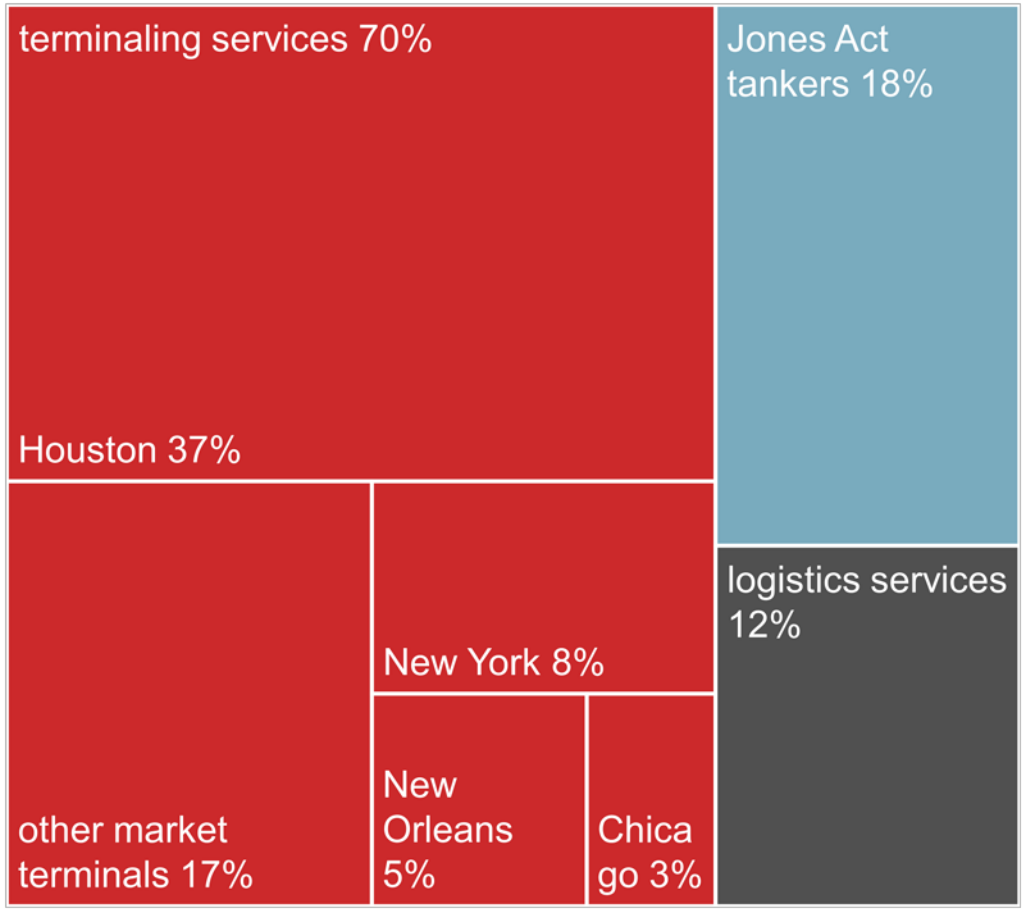
Stable fee-based earnings stream derived from customer service solutions

a) Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Terminals Segment Services

Offering unmatched market access with modal flexibility alongside value-added terminaling services

2021B EBDA: $1.0 BILLION[a]



terminal services

- Concentrated in key industry supply & demand market hubs
- Houston Ship Channel assets serving the world's most-competitive refining & petrochemical industry
- Complementary regional distribution terminals
- ***Allows indispensable connectivity to markets***

logistics services

- In-plant handling of steel, scrap & ores serving steel production
- Petroleum-coke handling supporting refineries
- In-plant logistics services supporting petrochemicals
- ***Serves world-class production facilities***

Jones Act tankers

- Most modern & efficient Jones Act tanker fleet
- Handle refined products & crude with renewables & chemicals capabilities
- ***Meets domestic maritime demand***

Service offering of full supply chain logistics solutions

a) Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

Our Liquid Hubs

Strategically located to serve key supply & demand markets

Houston Ship Channel

- Serves the world's most competitive supply of refined products & petrochemicals
- 9 terminals providing ~43 million barrels of capacity[a]
- $382 million 2021B EBDA[b]

New York Harbor[c]

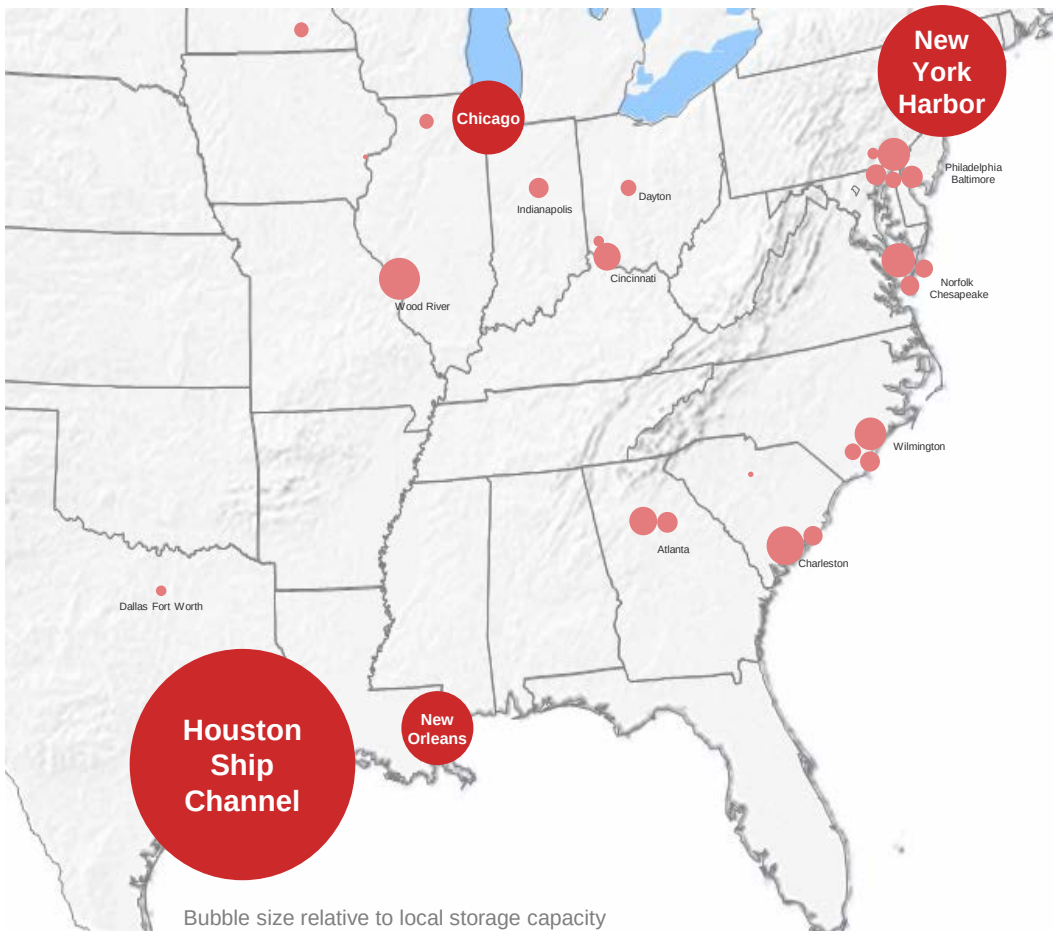
- Serves as the world's largest & most-liquid refined product clearinghouse
- 5 terminals providing ~14 million barrels of capacity
- $81 million 2021B EBDA[b]

New Orleans

- Serves growing renewable & chemical markets along the Mississippi River
- 6 terminals providing ~5 million barrels of capacity
- $51 million 2021B EBDA[b]

Chicago

- Serves as the nation's ethanol clearinghouse, pricing & trading hub
- 4 terminals providing ~5 million barrels of capacity
- $29 million 2021B EBDA[b]



80 million barrels of storage capacity centered around key market hubs

a) Houston Ship Channel includes tankage associated with Products segment splitter at Galena Park; capacities represented on a gross basis.
b) Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
c) New York Harbor excludes divested Staten Island terminal.

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

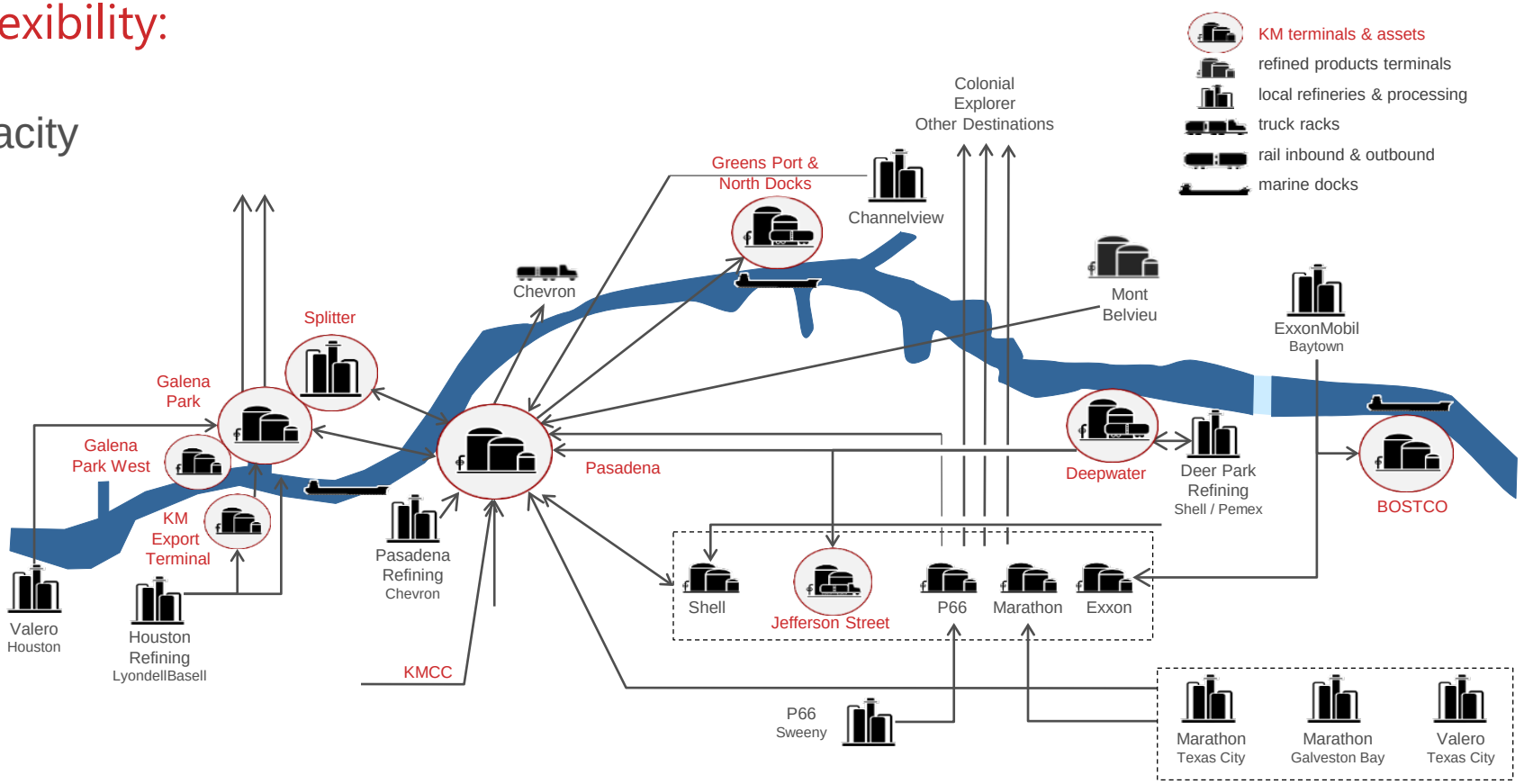
16 cross-channel pipelines

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.

Our Integrated Terminal Network on Houston Ship Channel

Industry leading capabilities in the world's most competitive refining & petrochemical center

Unmatched inbound connectivity

Refineries	Pipeline connectivity to all HSC refineries providing gasoline, distillate & blendstock supply	Pasadena Galena Park Kinder Morgan Export Terminal (KMET) BOSTCO
Chemicals	Pipeline & barge receipts of chemicals & gasoline blending components	Pasadena Galena Park
Ethanol	Unit train receipts of domestic ethanol production	Deer Park Rail Terminal Pasadena Jefferson Street Truck Rack
Mont Belvieu NGLs	Pipeline connectivity to Mont Belvieu fractionators for butanes & natural gasoline	Pasadena Galena Park

Value-added services

Aggregation, staging & storage services	Gasolines & distillates Black oils Chemicals Renewables	Pasadena, Galena Park, BOSTCO, KMET, Deer Park Rail Terminal, Jefferson Street Truck Rack, et al.
Product blending services	Gasolines & distillates	Pasadena, Galena Park, KMET
Bunker blending services	Residual oils Black oils Distillates	BOSTCO

Outbound market access

Truck rack	Local truck rack loadings to local markets	Jefferson Street Truck Rack
Pipelines	Pipeline origination to domestic markets	Pasadena Galena Park
Rail	Unit train origination of refined products to Mexico	Greens Port
Marine	Docks for export, as well as Jones Act domestic shipments	Pasadena Galena Park BOSTCO KMET North Docks

"More than just a bucket"

Value-added customer solutions for trading, blending, optimization & market access

Tankers Meeting Domestic Maritime Demand

Most modern & efficient Jones Act tanker fleet

American Petroleum Tankers

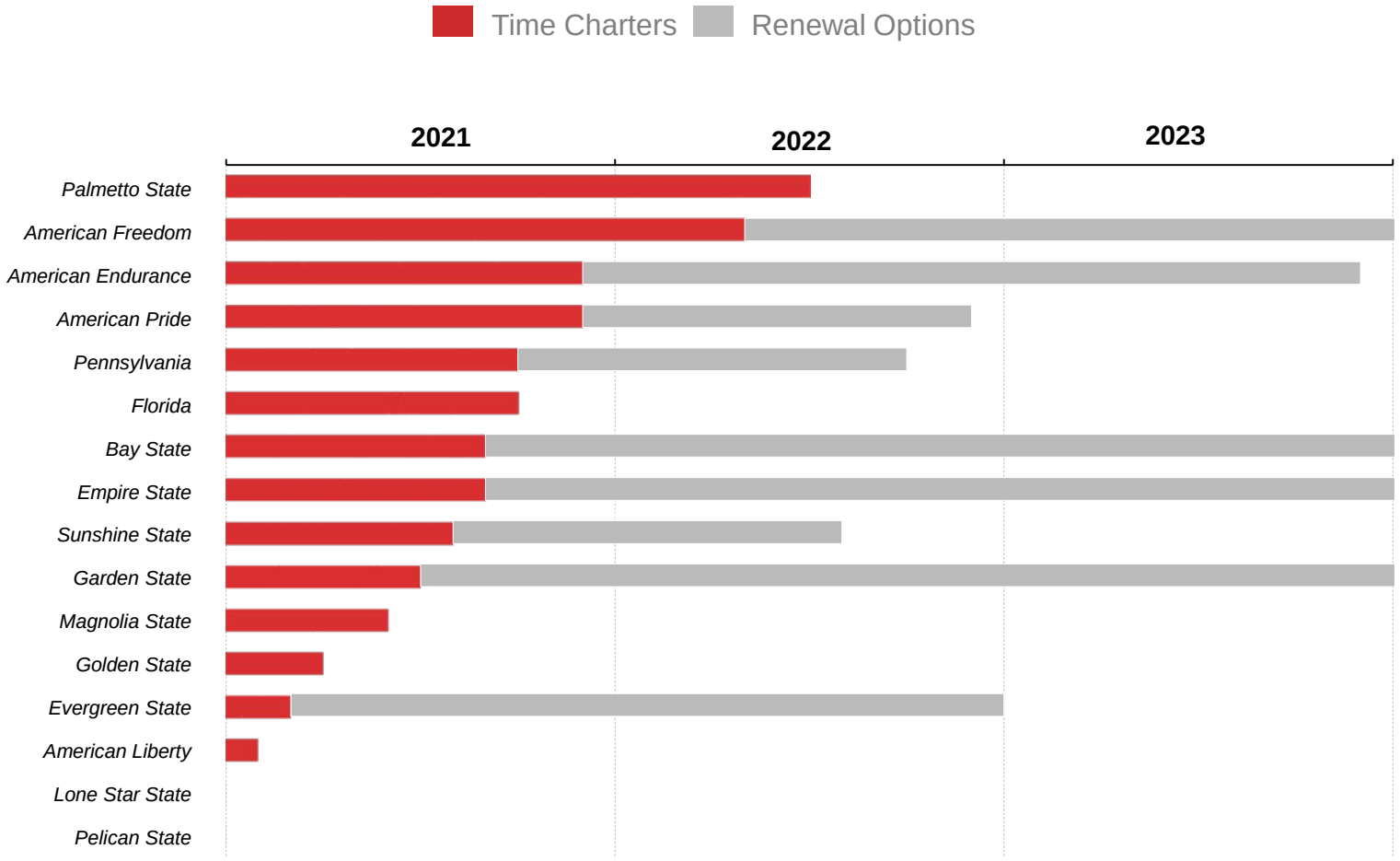
- 16 modern, fuel-efficient tankers
- Largest Jones Act tanker fleet
- Most modern fleet with an average age of 6.8 years

Near-term market softness…

- COVID demand destruction resulting in temporary excess supply of Jones Act tonnage
- Near-term weakness: term charters generally unavailable
- Two APT tankers have been idled to reduce operating expenses

…worked off as favorable supply & demand dynamics take foot

- Attractive long-term fundamentals
- Competitive U.S. Gulf refinery supply
- Recovering refined product demand
- No new tankers under construction
- Ageing U.S. Jones Act fleet
- Emerging renewables trade



Jones Act market with significant barriers to entry & sound long-term fundamentals

Bulk Commodities

Diversified product & logistics service offerings

Petroleum Coke

One of the nation's largest handlers

8%

2021B Segment Revenue[a]

- Handle ~40% of Midcontinent & Gulf Coast production[b]
- In-plant refinery bulk-handling
- Export terminaling services
- Aggregation & blending at export terminals

Metals & Ores

Supporting steel manufacturing

7%

2021B Segment Revenue[a]

- Feedstock ores & scrap
- Finished product handling of coils, plate, bar, billets & pipe
- Break-bulk imports & export terminals
- In-plant steel logistical services

Coal

Advantaged export position

4%

2021B Segment Revenue[a]

- U.S. coal exports
- Steam & metallurgical coal
- Highly efficient East & Gulf Coast terminals

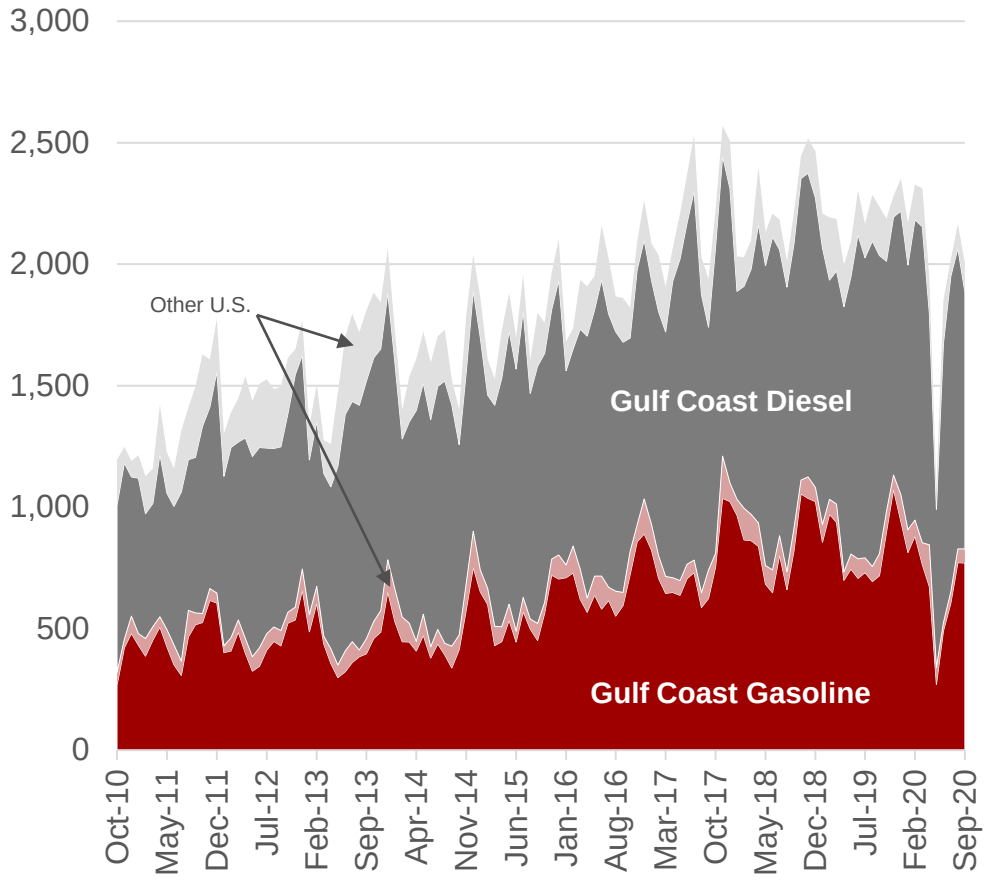
a) 2021 budgeted Terminals Segment revenues of $1.8 billion, 25% from bulk products.
b) marketable petroleum coke.

Meaningful Growth in Gasoline & Diesel Exports

Globally competitive U.S. Gulf Coast refiners increasingly serve growing export markets

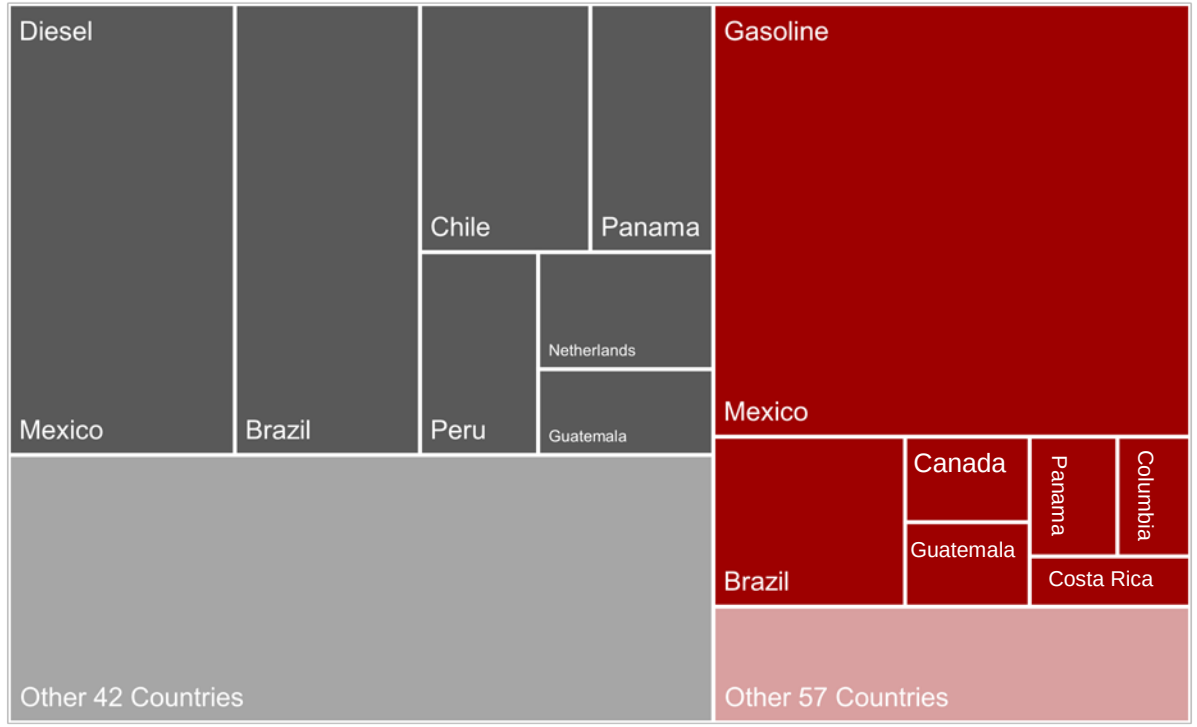
U.S. REFINED PRODUCT EXPORTS[a]

thousand barrels per day



USGC EXPORT DESTINATIONS[a]

trailing twelve months



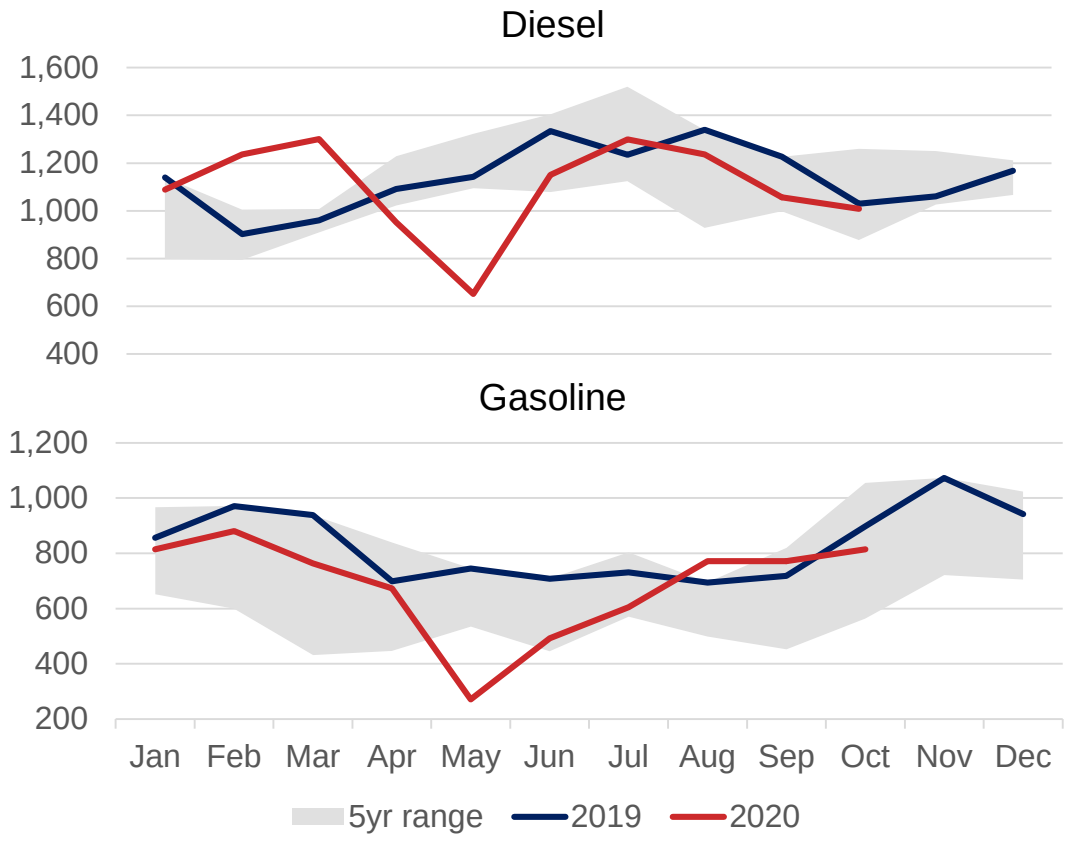
Over 2.0 mmbbld of U.S. exports of gasoline & diesel & growing

a) Source: U.S. Energy Information Administration (through Sep-2020); diesel inclusive to total distillates; gasoline exports include both finished product and blendstocks.

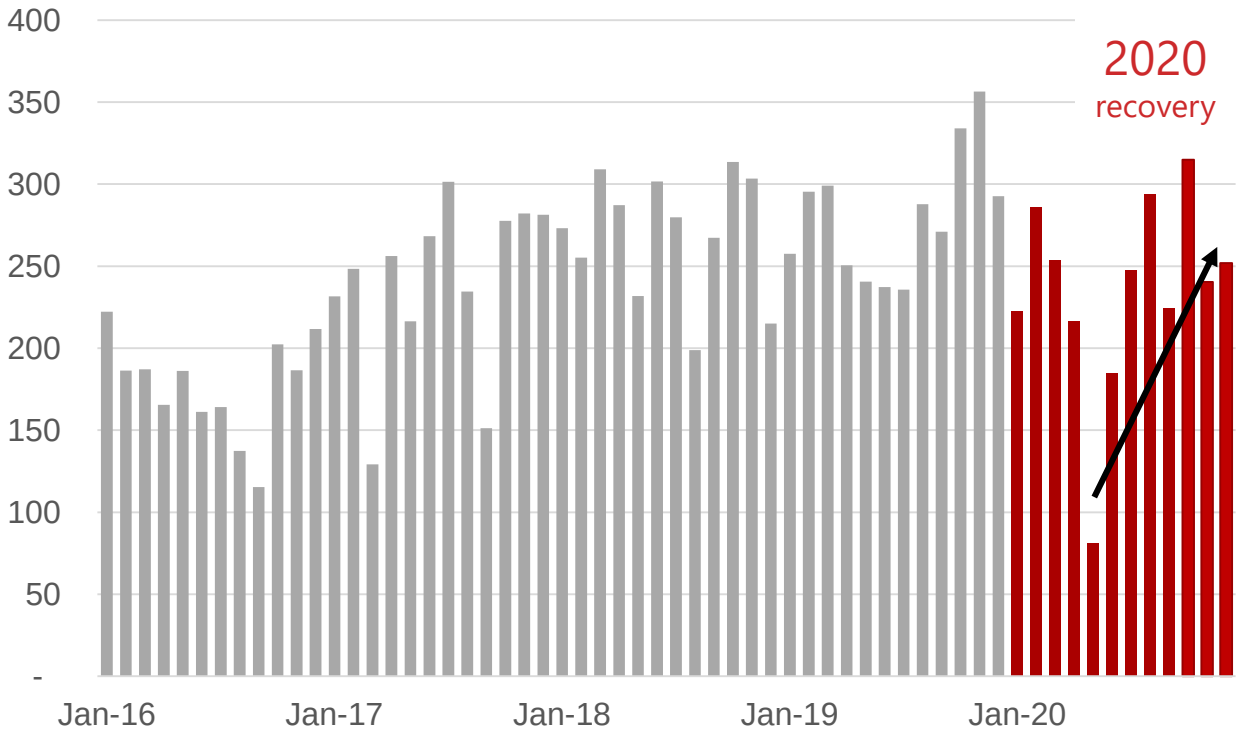
Leading Exporter of U.S. Gasoline & Diesel

COVID recovery & prospective long-term growth in USGC product exports

US GULF EXPORTS[a]
thousand barrels per day



OUR HOUSTON SHIP CHANNEL EXPORTS[b]
thousand barrels per day



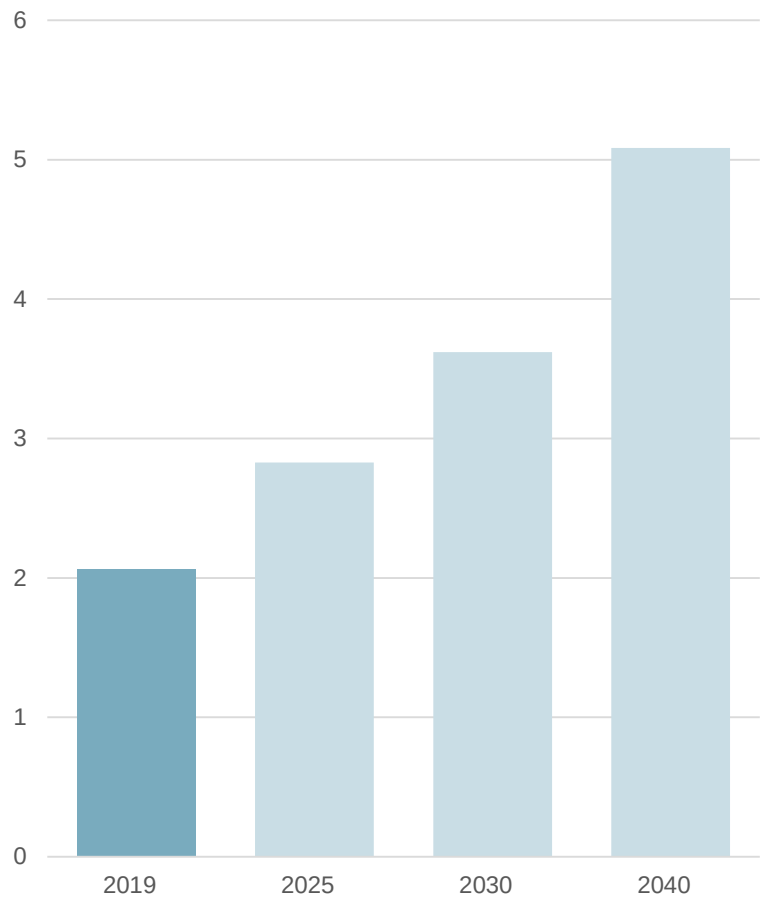
Expanded dock capacities capable of up to 600 thousand bbld of export volumes

a) U.S. Energy Information Administration (through Sep-2020); diesel exports inclusive of total distillates; gasoline exports include both finished product & blendstocks.
b) KM internal data including export origination on both marine vessel & railcar.

Attractive Potential for Liquid Biofuels

Policy support & efficient infrastructure important to increasing adoption of ethanol, biodiesel & other low-carbon fuels

GLOBAL BIOFUELS DEMAND OUTLOOK
million barrels per day



Stated policies scenario projects:

~75% or 1.5 mmbbld increase by 2030

~150% or 3.0 mmbbld increase by 2040

Even more in a 2-degree scenario

~40% of growth from the U.S. & China

Policies such as the U.S. Renewable Fuel Standard & China's E10 program underpin this level of increase

5x more investment required each year

Over $10 billion projected to be spent on production capacity through 2030 versus just $2 billion in 2019

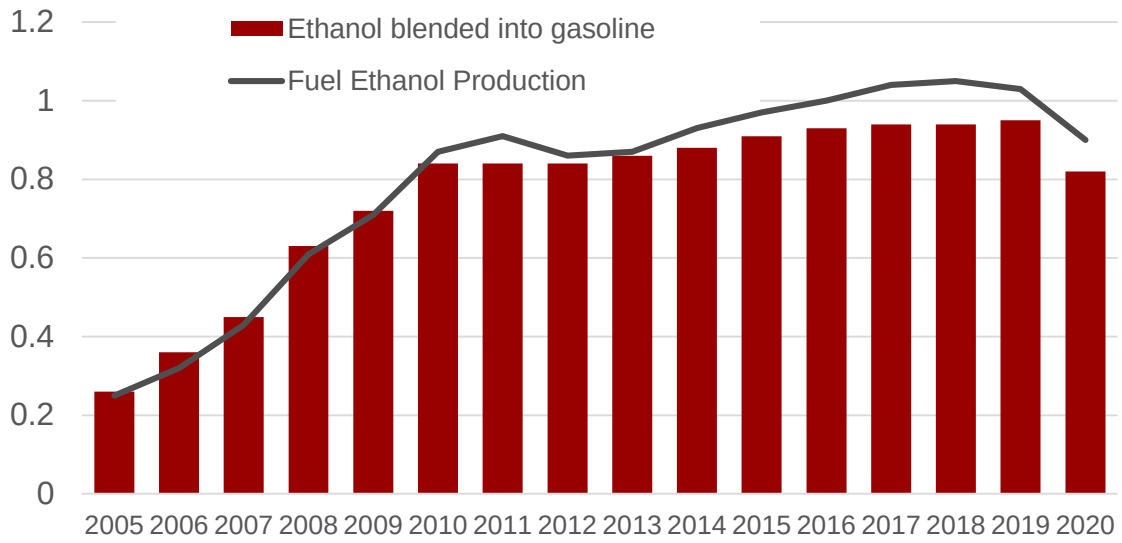
Source: International Energy Agency, World Energy Outlook, October 2020 (Stated Policies Scenario).
Note: Statistics relative to 2019, the latest actual available.

Our Industry Leading Ethanol Capabilities

Handling nearly a third of domestic ethanol & positioned for growth

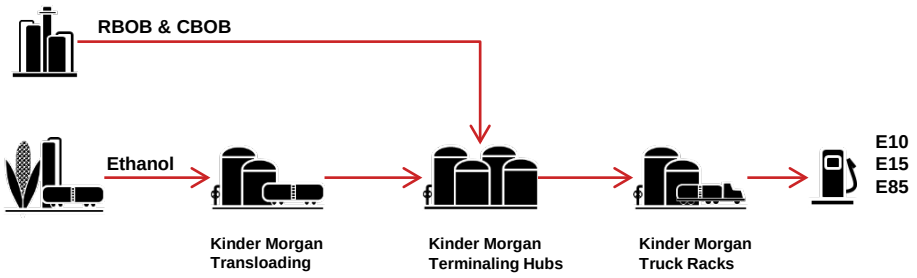
U.S. ETHANOL

million barrels per day



KINDER MORGAN RESPONSE

Efficient, full-service, logistics solutions



1	—	Market-making hub at Argo, IL
2	—	Pipelines transporting ethanol
9	—	Unit train ethanol transload receipt terminals
69	—	Truck racks blending ethanol into gasoline
275	—	2021B ethanol volumes, mbbld[(a)]

Significant past growth was driven by RFS

2020 COVID demand destruction alongside gasoline

Recent growth encumbered by E10 blend wall

Increasing near-term EPA RFS standards

Elimination of small refiner exemptions

Regulatory reform promoting higher-level blends, E15 & E85

Enabling customers across our network to deploy renewables today

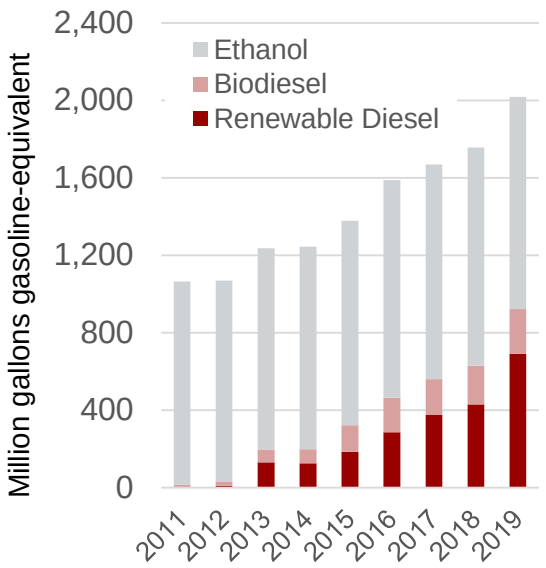
a) Includes terminal throughputs, transload terminals & rack ethanol blending; excludes non-fuel grade ethanol.

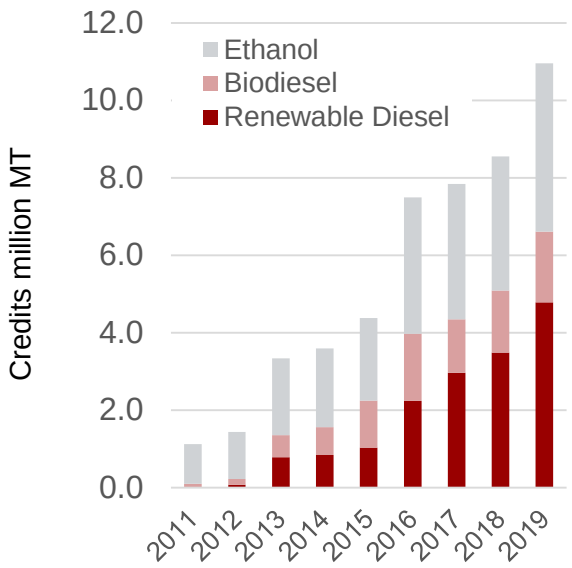
A Leading Position to Meet Renewable Diesel Growth

Advantaged footprint to provide logistics solutions for emerging products

CALIFORNIA LOW CARBON FUEL STANDARD[a]

alternative volumes & credits





Renewable diesel pathways to meet California LCFS standards

New plants, expanded plants & wholesale refinery conversions

California leading toward further States' adoption

OUR RENEWABLE DIESEL OPPORTUNITIES

by segment

TERMINALS

Significant market share of renewable diesel & feedstocks handled today

Growth opportunities for feedstock aggregation

- Advantaged Midwest & Gulf Coast footprint

Leverage existing storage & modal infrastructure toward supply chain solutions & site hosting

PRODUCTS

Growth opportunities for distribution

Extensive refined product pipeline & terminaling business on the West Coast & in California

- Railcar receipt & transloading at existing terminals
- Blending at our terminals
- Reference Products section in this presentation

Evaluating multiple opportunities to establish hubs for renewable products & feedstocks

a) Source: California Air Resources Board.

Our Unmatched Energy Storage & Distribution Infrastructure

Unrivaled offering of value-added industry solutions

TERMINALS SEGMENT HIGHLIGHTS
irreplicable collection of infrastructure & capabilities

79	terminals
1,600+	tanks
80	million Bbls of capacity
101	marine docks
56	ship capable
169	barge dock spots
422	truck bays (loading/unloading)
6,200+	combined railcar capacity
1,000+	railcar spots (loading/unloading)
3.5+	million square feet warehousing

Meeting the energy needs of today…

- core liquids solutions critical to our customers & industry
- the most competitive global infrastructure in the U.S. Gulf Coast
- expected increases in global export refined product supply
- expected continued petrochemical growth
- irreplicable & irreplaceable assets & capabilities

… & tomorrow: the logical choice for lower carbon fuels

- existing infrastructure tied into a large refining network
- existing zoned industrial facilities with favorable capital efficiencies (cost & schedule) versus new builds
- established customer trust
- current specialty product & blending capabilities
- positioned to meet emerging fuels needs

Existing infrastructure positioned to fuel the future

Our Logistics Solutions

Long-term macro fundamentals support our value propositions

Markets	Macro Trends	Our Value Propositions
Renewables	• Domestic growth in renewable, low-carbon alternative fuels • Renewable diesel investments to supply low carbon fuels • Further expected state & national standards • Continued need for logistics solutions	▪ Biofuel & feedstock liquid supply hubs & pricing points ▪ Multi-modal transportation modes: truck, rail, ship & barge ▪ Transload facilities serving existing distribution terminals ▪ Refined product biofuel blending to gasoline & diesel finished product
Refining	• Flat-to-declining domestic refined product demand • Rationalization / repurposing of challenged refineries • World's most competitive supply in U.S. Gulf Coast • Continued need for logistics solutions	▪ Hub terminal market access: local, domestic & export markets ▪ Blending capabilities to fully capture product value ▪ Complete supply chain services from blendstocks to finished products ▪ Dock expansions minimizing demurrage
Petrochemical	• Advantaged domestic petrochemical feedstocks • Low-cost NGL, natural gas & refinery derivatives • Promoting domestic expansion as global low-cost producer • Continued need for logistics solutions	▪ In-plant logistics solutions for infrastructure & operations ▪ Select terminal repurposing & plant site hosting ▪ Feedstock supply for natural gas, NGLs & refinery intermediates ▪ Dock capabilities for export-oriented growth

Value-added logistics services to the fuels of today & the future

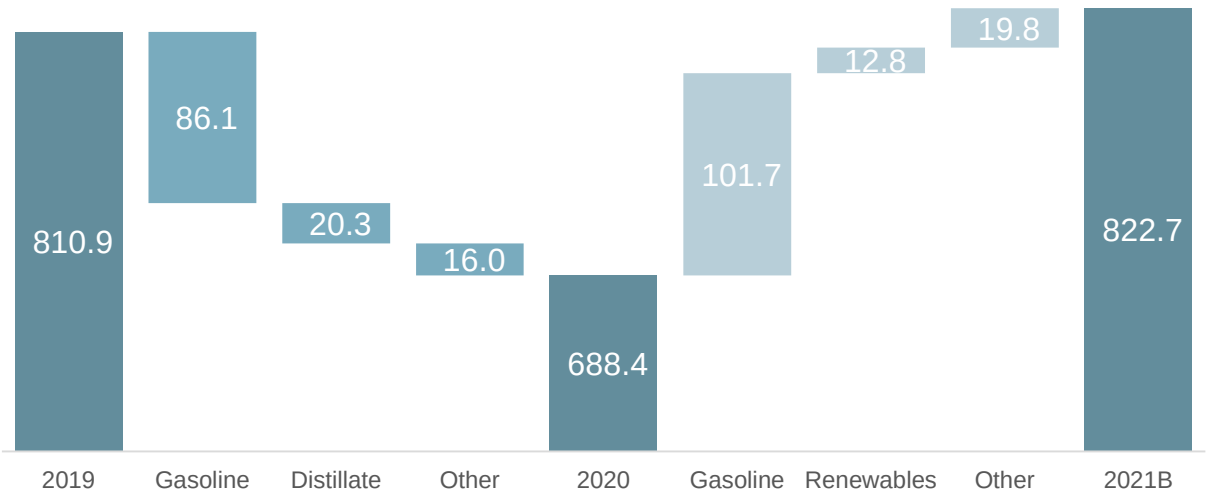
Terminals Throughput & Tonnage Statistics

2019 to 2021B comparison

	Throughput		Variance vs. 2020		2019 Throughput	Variance vs. 2019	
MMBbls	2020	2021B	MMBbls	%	2019	MMBbls	%
Gasoline	426.9	528.6	101.7	24%	513.0	15.6	3%
Distillate	122.7	126.3	3.7	3%	142.9	(16.6)	-12%
Petroleum Feedstocks	44.5	56.8	12.2	27%	49.9	6.8	14%
Renewables	41.2	54.0	12.8	31%	50.3	3.7	7%
Chemical	43.9	46.0	2.1	5%	44.5	1.5	3%
Vegetable Oils	6.3	7.7	1.4	23%	6.4	1.2	19%
Other	3.0	3.5	0.5	15%	3.7	(0.3)	-8%
	688.4	**822.7**	**134.4**	**20%**	**810.9**	**11.9**	**1%**

	Tonnage		Variance vs. 2020		2019 Tonnage	Variance vs. 2019	
tons (millions)	2020	2021B	mm tons	%	2019	mm tons	%
Ores/Metals (Bulk)	14.5	14.5	(0.0)	0%	15.6	(1.0)	-7%
Petroleum Coke	13.7	14.2	0.6	4%	13.8	0.5	3%
Coal	6.0	9.7	3.7	62%	10.0	(0.3)	-3%
Soda Ash	3.2	3.7	0.5	17%	4.4	(0.7)	-16%
Aggregate	3.9	5.6	1.7	43%	4.3	1.2	28%
Salt	2.0	2.3	0.3	15%	2.3	0.0	1%
Ores/Metals (Break-Bulk)	1.7	2.1	0.4	21%	1.8	0.3	16%
Other Bulk	1.1	1.4	0.2	20%	1.5	(0.1)	-7%
Fertilizers	1.0	1.2	0.1	11%	1.0	0.1	13%
Cement (Including Clinker)	0.8	0.9	0.1	12%	0.6	0.3	45%
	48.0	**55.6**	**7.6**	**16%**	**55.3**	**0.3**	**1%**

LIQUIDS THROUGHPUT year-over-year variance



Notes: Excludes refined product or crude oil volumes through Jones Act tankers. Excludes divested assets & assets held for sale. Petroleum feedstocks includes crude oil, black oil & refinery intermediates. Renewables includes ethanol, biodiesel & renewable diesel.

CO_2

Segment Presentation

CO_2 Segment Overview

World class, fully-integrated assets | CO_2 source to crude oil production & takeaway in the Permian Basin

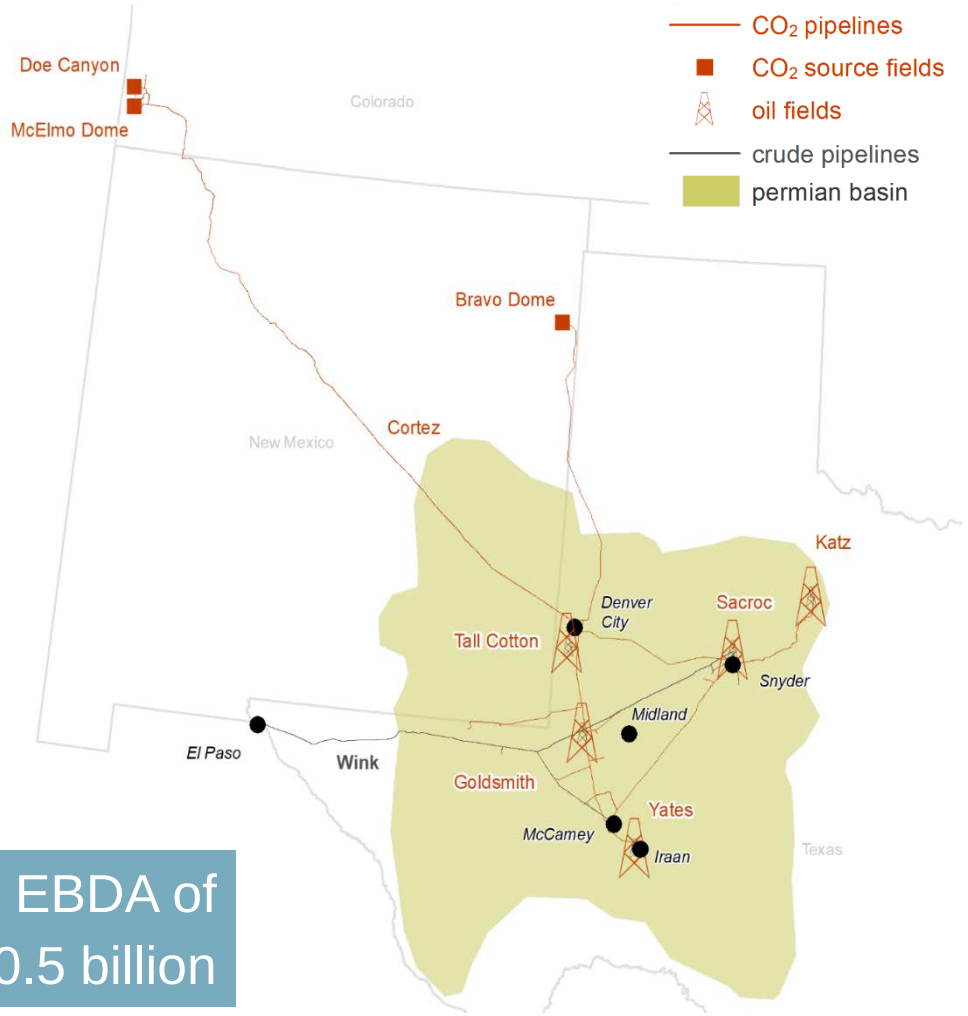
CO_2 & TRANSPORT

CO_2 Reserves	KMI Interest	NRI	Location	Est. OGIP tcf
McElmo Dome	45%	37%	SW Colorado	22.0
Doe Canyon	87%	68%	SW Colorado	3.0
Bravo Dome[a]	11%	8%	NE New Mexico	12.0

Pipelines	KMI Interest	Location	Capacity mmcfpd
Cortez	53%	McElmo Dome to Denver City	1,500
Bravo[a]	13%	Bravo Dome to Denver City	375
Central Basin (CB)	100%	Denver City to McCamey	700
Canyon Reef	97%	McCamey to Snyder	290
Centerline	100%	Denver City to Snyder	300
Pecos	95%	McCamey to Iraan	125
Eastern Shelf	100%	Snyder to Katz	110
Wink (crude)	100%	McCamey to Snyder to El Paso	145 mbbld

OIL & GAS

Crude Reserves[b]	KMI Interest	NRI	Location	Est. OOIP billion bbls
SACROC	97%	83%	Permian Basin	2.8
Yates	50%	44%	Permian Basin	5.0
Katz	99%	83%	Permian Basin	0.2
Goldsmith	99%	87%	Permian Basin	0.5
Tall Cotton	100%	88%	Permian Basin	0.7



2021 budgeted EBDA of ~$0.5 billion

Note: OGIP = Original Gas In Place. OOIP = Original Oil In Place. 2021 budgeted EBDA based on Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.

a) Not KM-operated.

b) In addition to KM's interests listed, KM has a 22%, 51% & 100% working interest in the Snyder gas plant, Diamond M gas plant & North Snyder gas plant, respectively.

Enhanced Oil Recovery Process

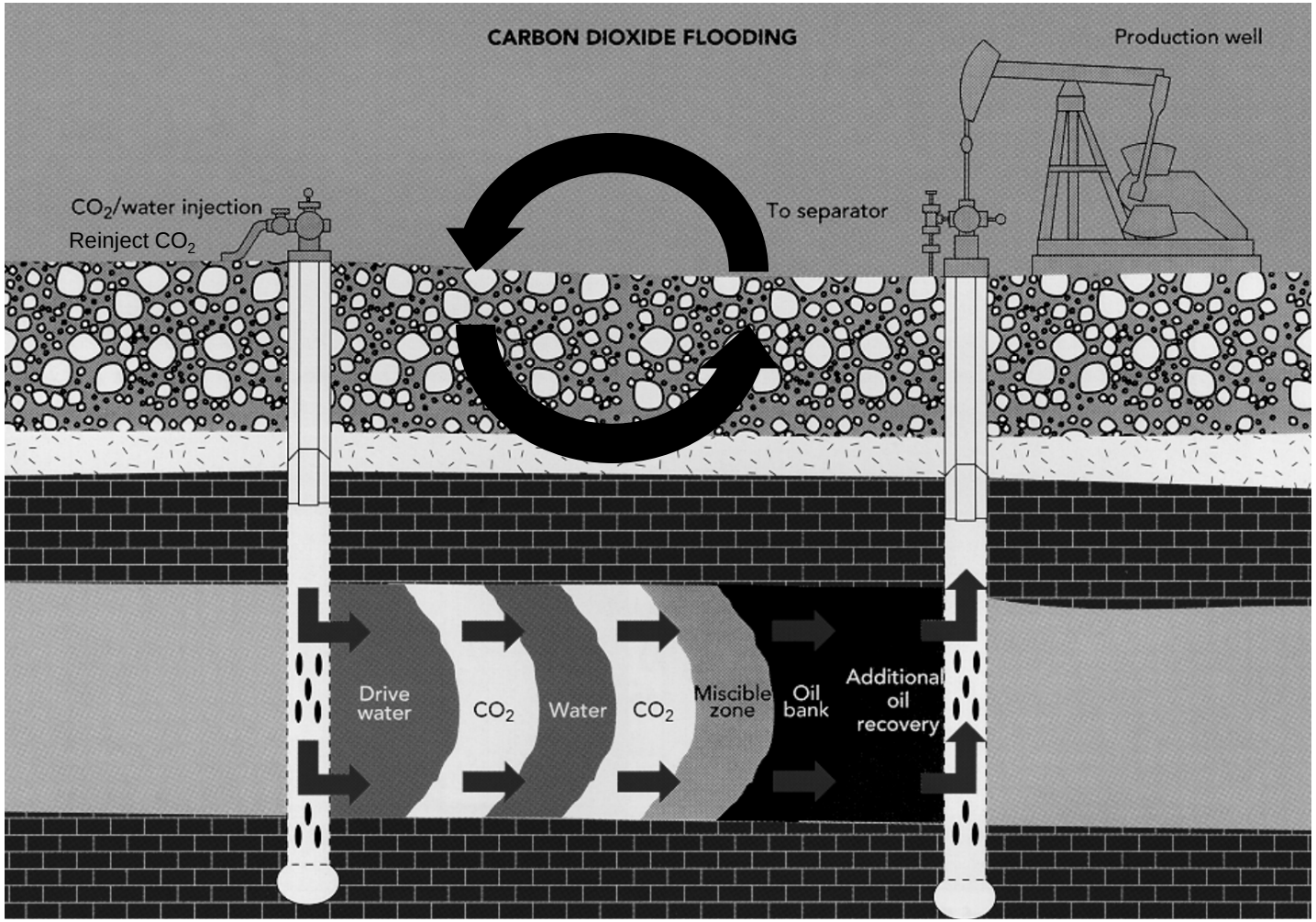
Specializing in the gas injection method of enhanced oil recovery (EOR)

Three phases of oil & gas production

PRIMARY RECOVERY	SECONDARY RECOVERY	TERTIARY (ENHANCED) RECOVERY
10-20% OOIP recovered	20-40% OOIP recovered	30-60% OOIP recovered
Natural pressure from reservoir drives oil to pumps	Gas injection & waterflooding with goal to maintain reservoir pressure	Various injection methods with goal to reduce viscosity of oil

Methods of enhanced oil recovery

- Thermal injection – steam
- Chemical injection – polymers, surfactants
- Gas injection – CO_2, natural gas, nitrogen
  - Accounts for nearly 60 percent of U.S. EOR production



Own & operate naturally occurring CO_2 source, pipelines & oil fields in the Permian

Source: DOE, https://www.energy.gov/fe/science-innovation/oil-gas-research/enhanced-oil-recovery.

Key Factors Driving the Success of Our CO_2 Segment

Maximizing returns through financial discipline & innovation

Advantaged Assets

- Vertically integrated & Permian focused
- Produce & transport >80%[a] of the CO_2 delivered into the Permian
- Upside potential – history of extending productive life of fields
- CO_2 supply will lead to additional tertiary recovery
- Positioned for future 45Q carbon capture opportunities

Highly-Skilled Team

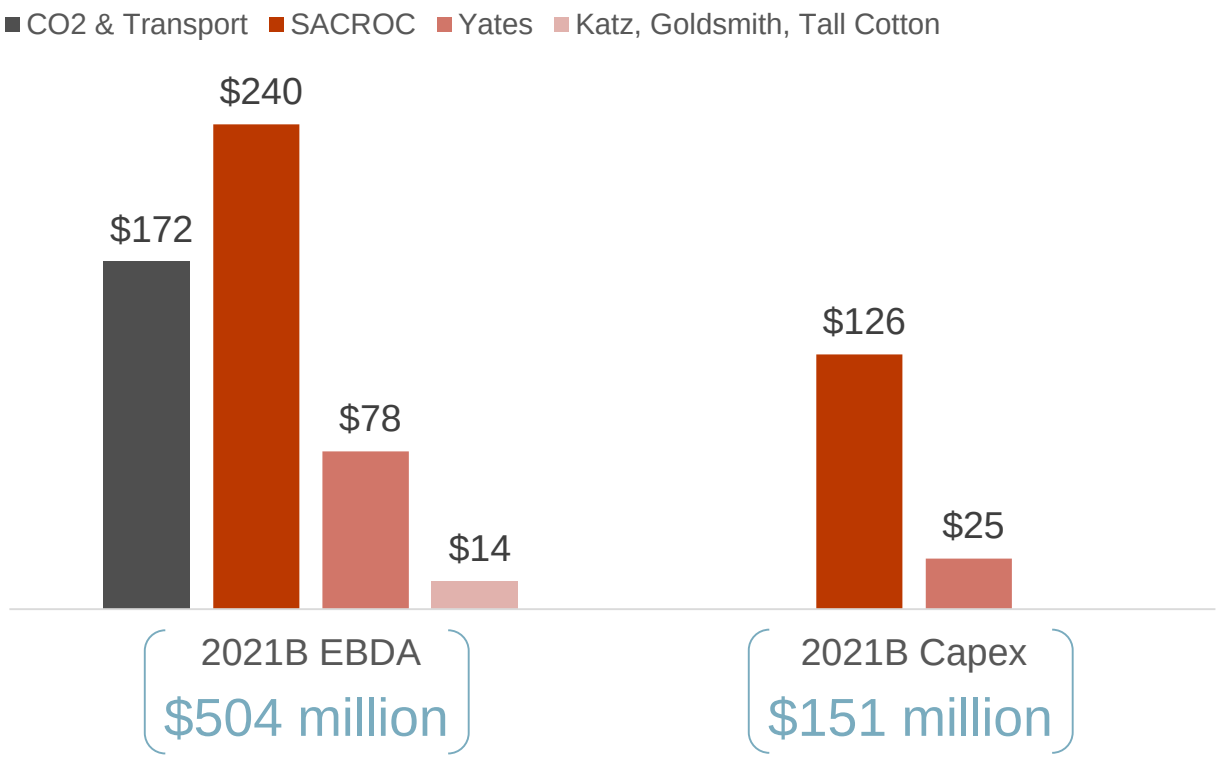
- Industry-leading experience in highly specialized business will facilitate development of CCUS in North America
- Continually executing on technological advancements
- Consistently achieve production & capex budget targets
- Proven ability to adjust capital program when markets change

Profit-Focused

- High-return asset base
- Invest based on project economics – not to maintain production
- Manage commodity price volatility with consistent hedge policy
- Healthy operating margins driven by low cost structure
- Meaningful free cash flow & profitable through commodity cycles

a) KM data & EPA.

CO_2 Segment Budget & Sensitivities



2021B assumptions	Change	Potential Impact to Adjusted EBITDA & DCF (full year)
Crude oil production 41 mbbld gross (29 mbbld net)	+/- 5% in gross volumes	$21.6 million
CO_2 sales 693 mmcfd gross (331 mmcfd net)	+/- 50 mmcfd in gross volumes	$6.9 million
$43/bbl WTI crude oil price	+/- $1/bbl WTI	$1.3 million
41% NGL / crude oil price ratio	+/- 1% NGL / crude oil price ratio	$0.9 million
$0.30/bbl Mid / Cush differential	$0.10/bbl Mid / Cush differential	$0.1 million

Proven capital discipline

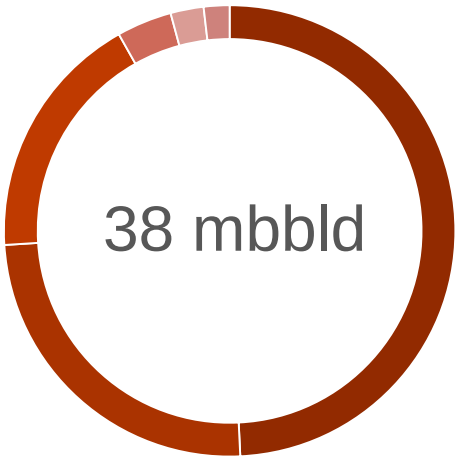
2021B CO_2 Segment Free Cash Flow of $339 million

Note: 2021B Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations. Total capex includes capitalized CO_2.

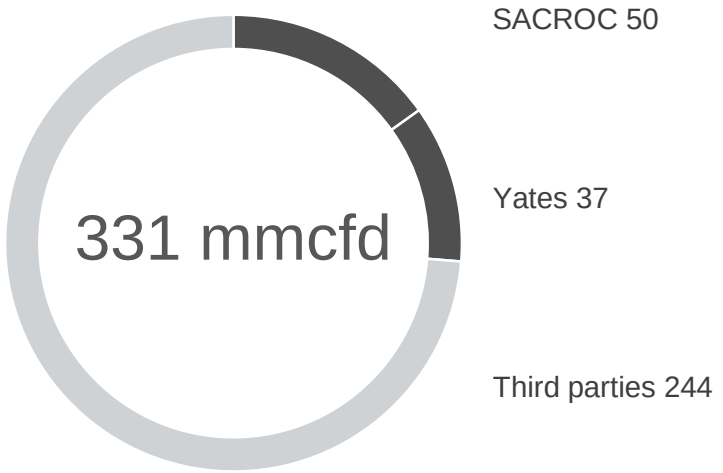
CO_2 Segment Budgeted Volumes & Highlights

2021B NET OIL & NGL PRODUCTION
mbbld

SACROC oil	18.7
SACROC NGL	9.4
Yates	6.8
Katz	1.5
Goldsmith	0.9
Tall Cotton	0.7



2021B NET CO_2 SALES
mmcfd



OIL & GAS

- Majority of required takeaway capacity provided by KM-owned Wink pipeline
- ~90% of 2021B oil production hedged to WTI price
- Mid-Cush differential applies to ~26.9 mbbld of the 2021B oil production, of which 24.6 mbbld (or 91%) is hedged

CO_2 & TRANSPORT

- Supplies >80% of CO_2 to Permian including 100% to KM oil & gas business
- 100% of 2021B CO_2 production is contracted, including 84% subject to minimum volume commitments
- ~8 years weighted average remaining contract life with third parties

CO_2 Segment 2021 Oil & Gas Major Projects

Major projects expected to generate attractive returns in multiple commodity price environments

Asset	Project	2021B capex	Commentary	ATIRR% at flat WTI price scenarios			
				Forward Curve	$43	$45	$50
SACROC	Expansion Projects	$126mm	— Activate remaining 10 of 33 Conventional West Shore Project Area Patterns — Complete 3 Bypassed Pay Zonal Horizontal Producers — Complete Town Center Seismic & East of Southwest Bank injection tests — Implement Bullseye Phase 3 project — Execute +/-25 Conformance projects	30%	26%	30%	40%
Yates	Horizontal Drain Hole Program & Other	$25mm	— Drill 40 Horizontal Drain Hole wells — Continue Surfactant stimulations — Execute on pilot of second phase double displacement process	47%	43%	48%	61%

Note: 2021B capex includes related CO_2 purchases. Forward curve strip price as of December 2020.

Extending Productive Life of Mature Fields

Innovation & team work continue to push SACROC decline curve flatter

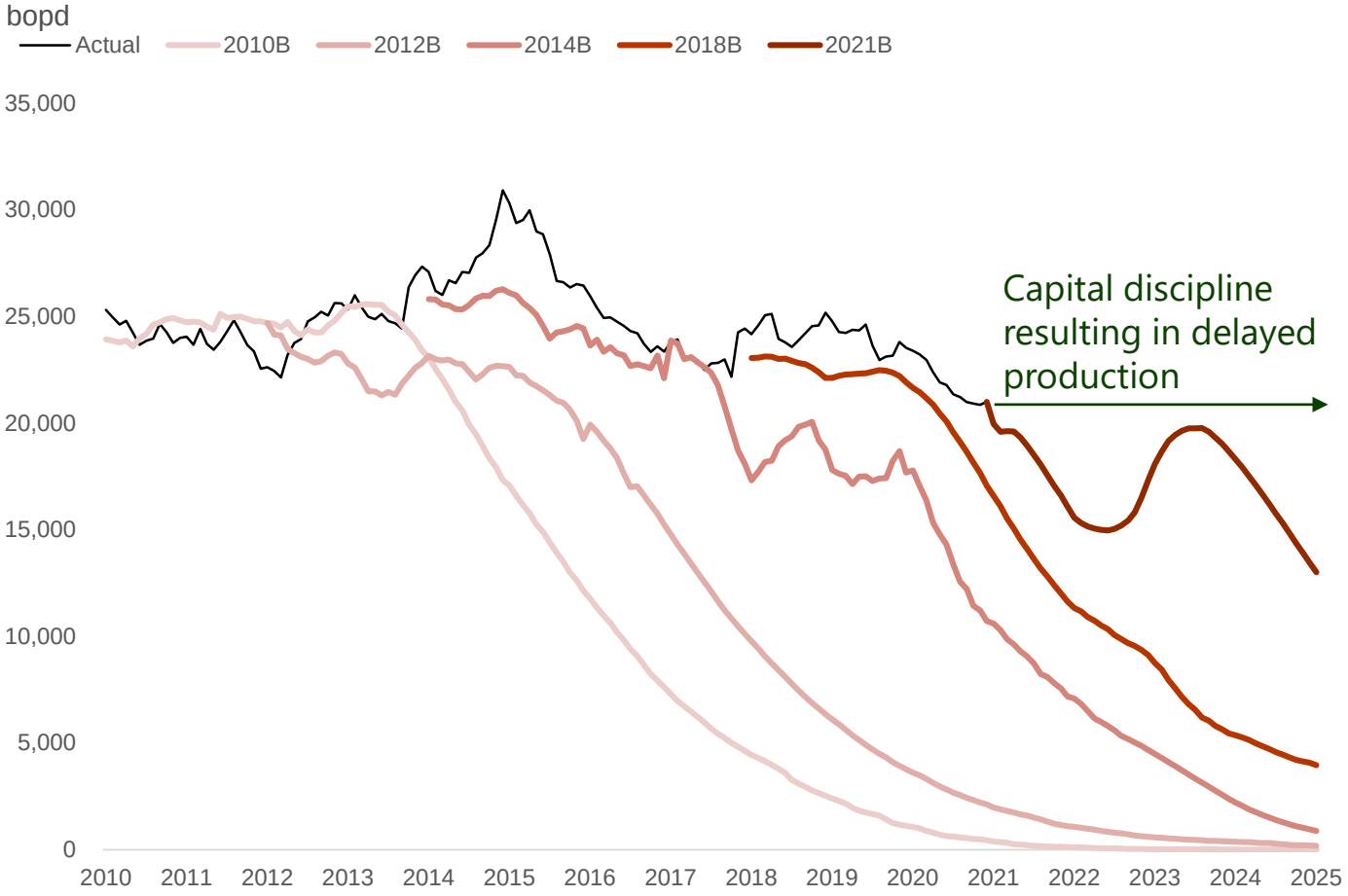
Significant amounts of recoverable oil in place

- SACROC is estimated at 2.8 billion barrels of original oil in place (OOIP)
  - Executing Transition Zone & Conventional projects
- Evaluating other areas of the SACROC field
- Yates is estimated at 5.0 billion barrels of OOIP, representing another large resource base

Technical expertise will drive future success

- Long track record of expanding the field through advanced technology & new exploitation techniques
- Advanced seismic reprocessing used to identify new development projects like Transition Zone
- Horizontal drilling technology has improved recovery
- Conformance technologies & techniques have led to redevelopment opportunities

SACROC NET OIL PRODUCTION FORECASTS

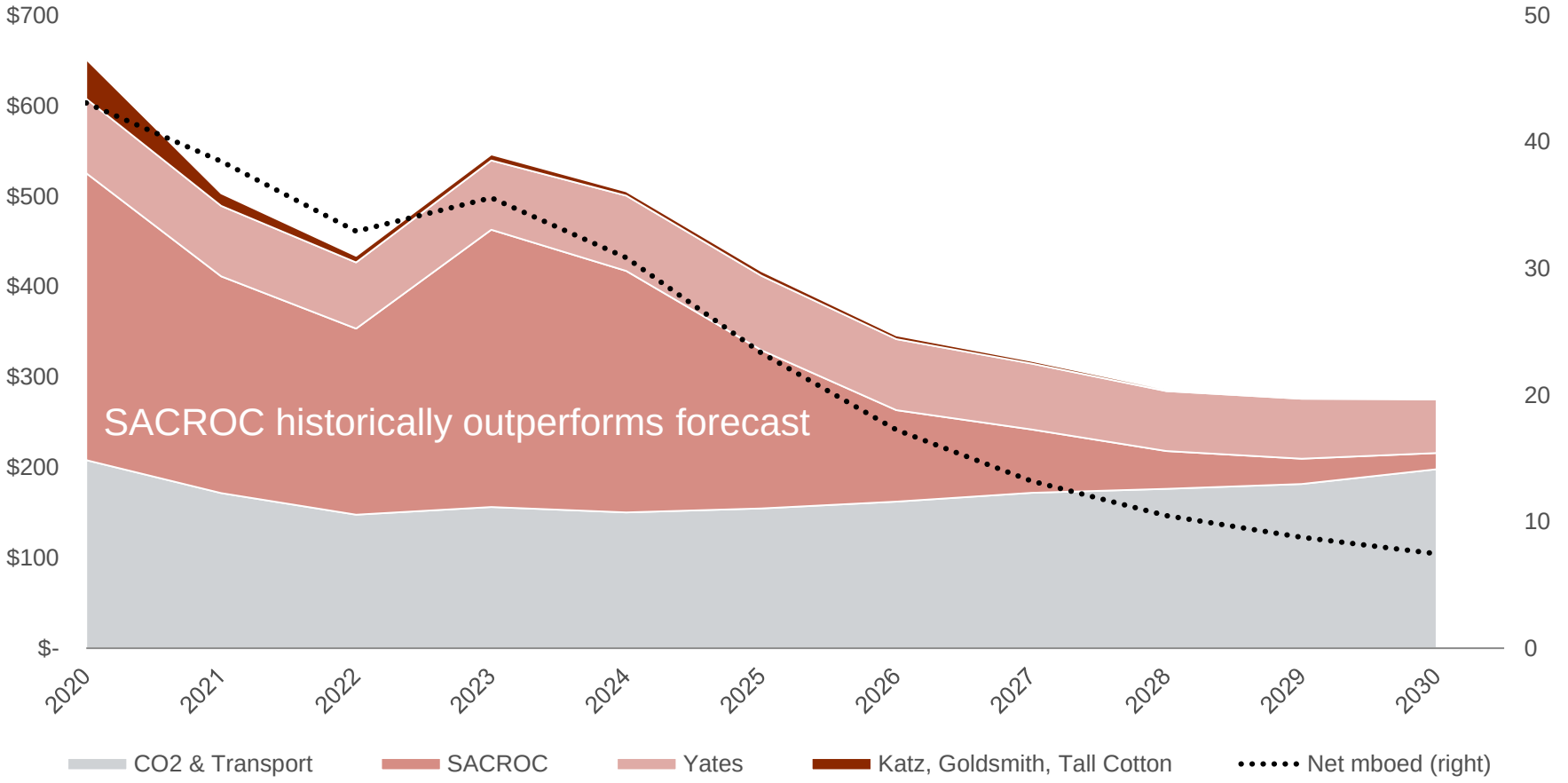


CO_2 Segment Long-Term Growth Outlook

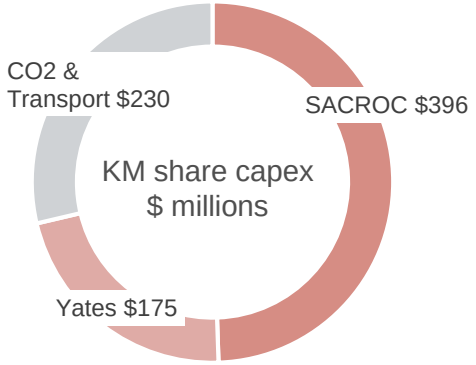
Projected EBDA, net production & development plan

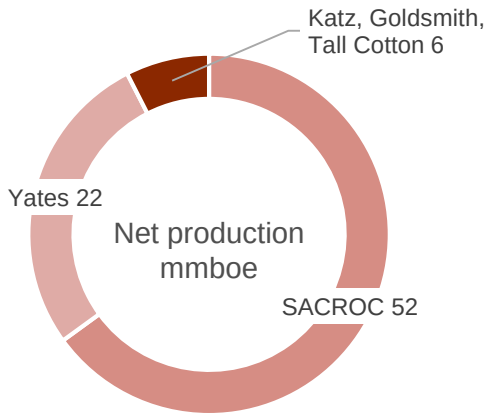
EBDA[a]
$ millions

NET PRODUCTION
incl. NGL & residue gas (mboed)



10 YEAR DEVELOPMENT PLAN
2021 – 2030



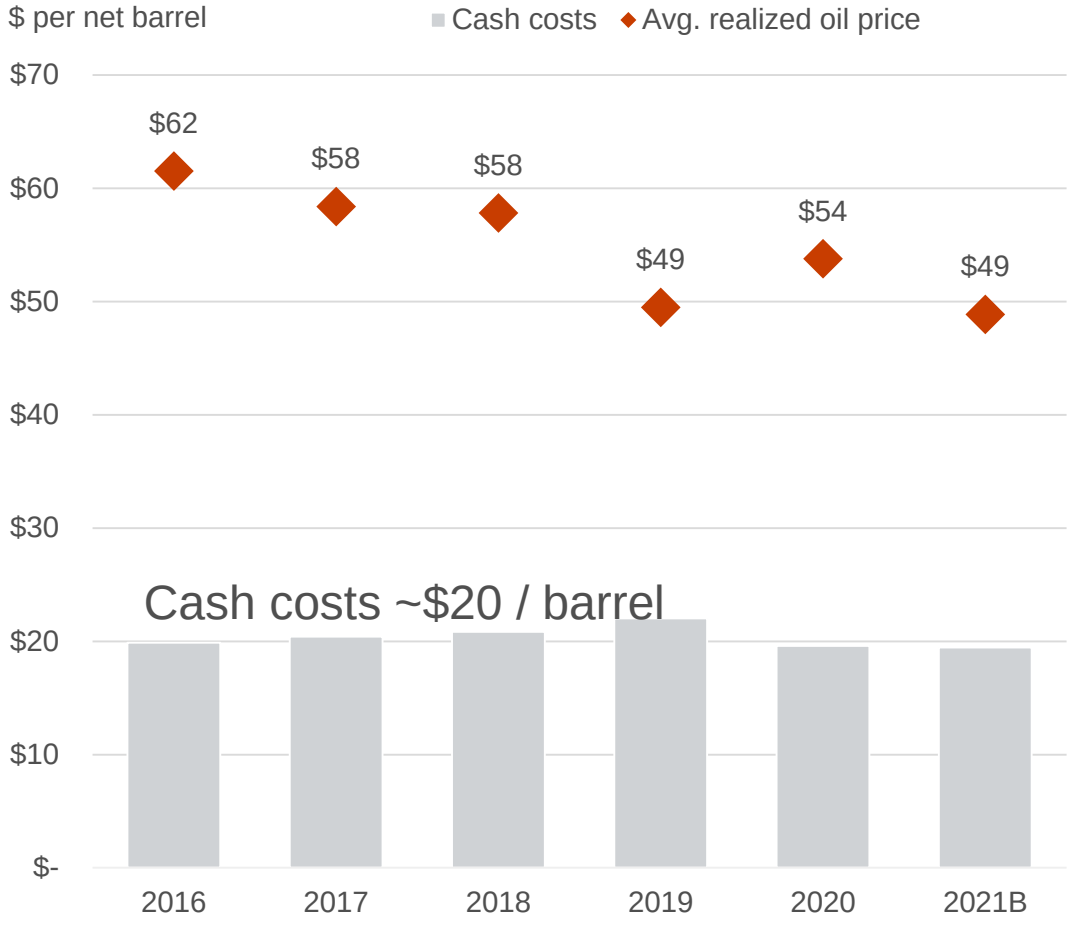


Note: 2021B Adjusted Segment EBDA. See Non-GAAP Financial Measures & Reconciliations.
a) Segment EBDA excludes intersegment eliminations related to CO_2 purchase profits. Assumes crude oil price of $43 / bbl in 2021, $50 / bbl in 2022 & $55 / bbl thereafter.

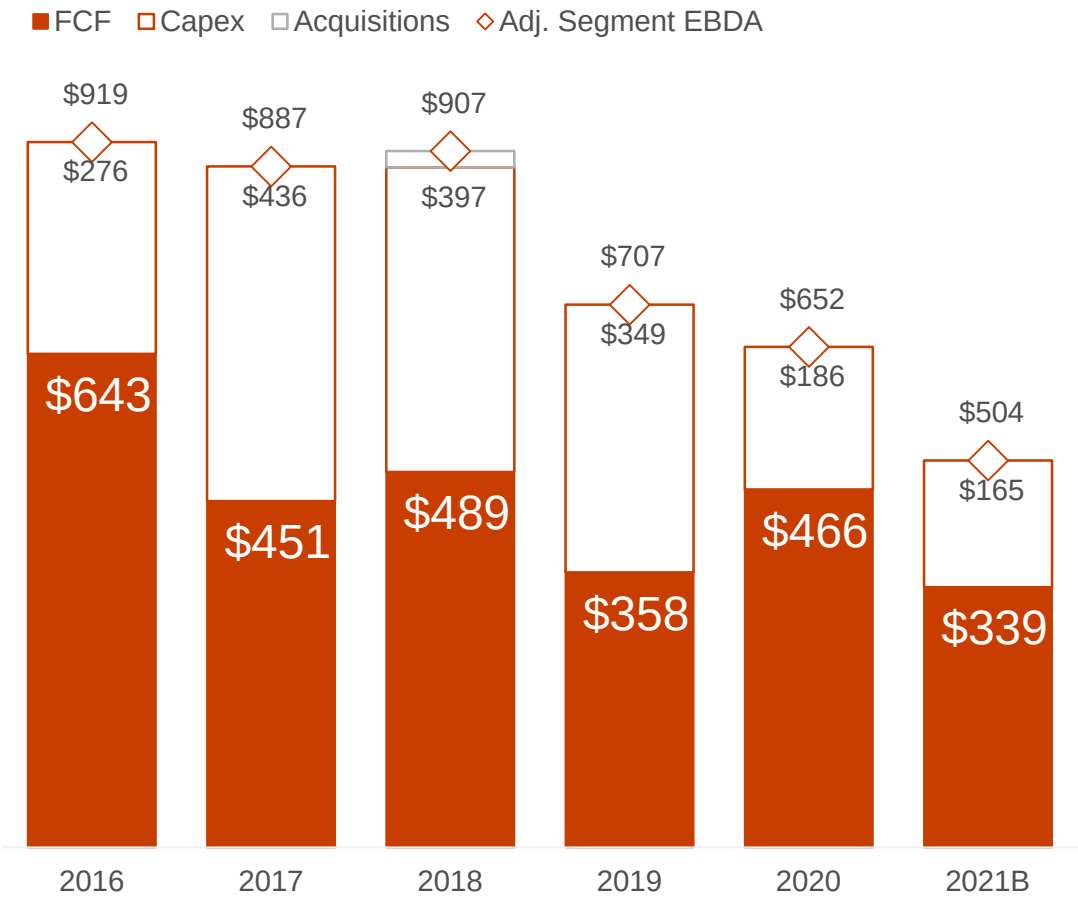
CO_2 Segment Consistently Generates Free Cash Flow

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

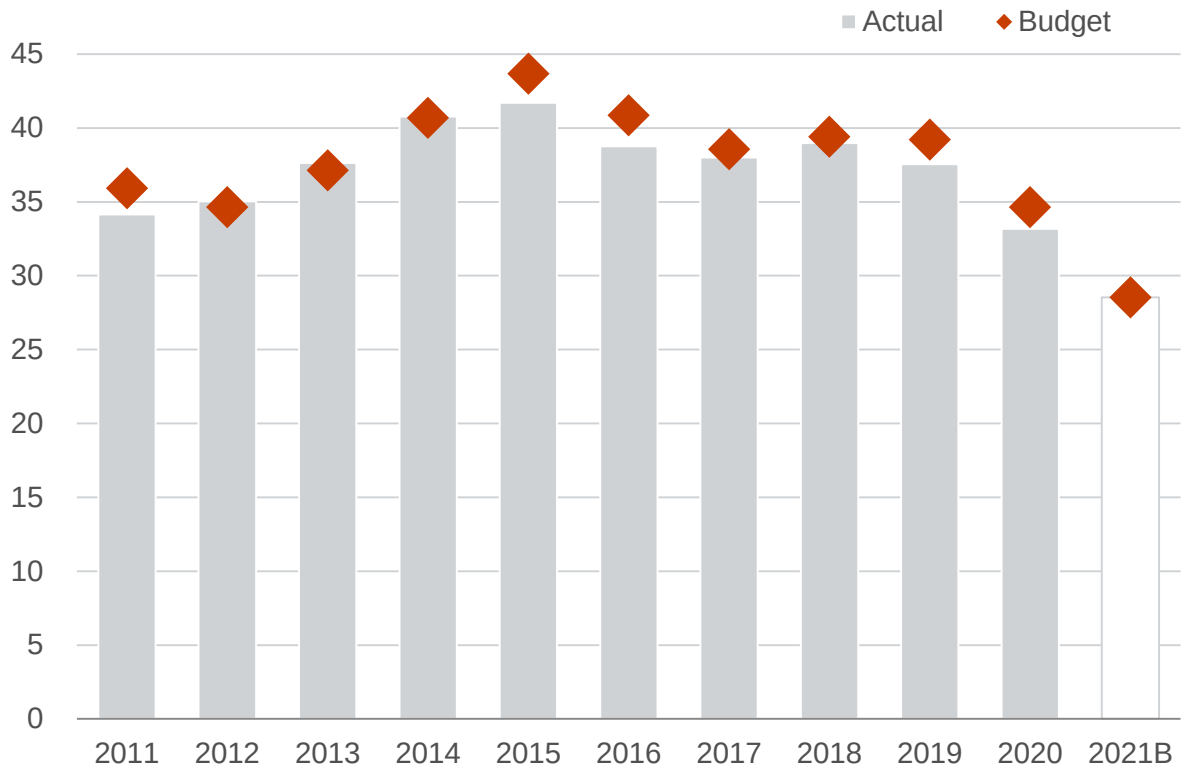


Note: Cash costs & revenue per net oil barrel, including hedges where applicable. See Non-GAAP Financial Measures & Reconciliations for CO_2 Free Cash Flow.

CO_2 Segment Predictable Volumes & Hedged Commodity Price

Mitigating uncertainties where possible | EOR oil & gas production represents ~5% of KMI business mix

NET OIL PRODUCTION: ACTUALS VS. BUDGET mbbld



Stable & predictable production over many years with actual oil production within 2% of budget 2011-2020

HEDGED VOLUMES as of 1/7/2021

	2021	2022	2023	2024	2025
Crude oil - West Texas Intermediate					
$/bbl	$ 50.37	$ 50.71	$ 49.08	$ 43.78	
bbl/d	25,700	11,700	6,650	1,850	
NGLs					
$/bbl	$ 29.40				
bbl/d	4,584				
Midland-to-Cushing basis spread					
$/bbl	$ 0.26				
bbl/d	24,550				
Argus Current Month Average basis spread					
$/bbl	$ (0.23)				
bbl/d	24,900				

Disciplined hedge policy mitigates near-term price volatility impact on expected cash flows

Note: Business mix based on Adjusted Segment EBDA per 2021 Budget.

Carbon Capture Utilization & Storage (CCUS)

Positioned to leverage our existing expertise & capabilities to provide CCUS services in the future

Our experience & current operations cover the CCUS value chain

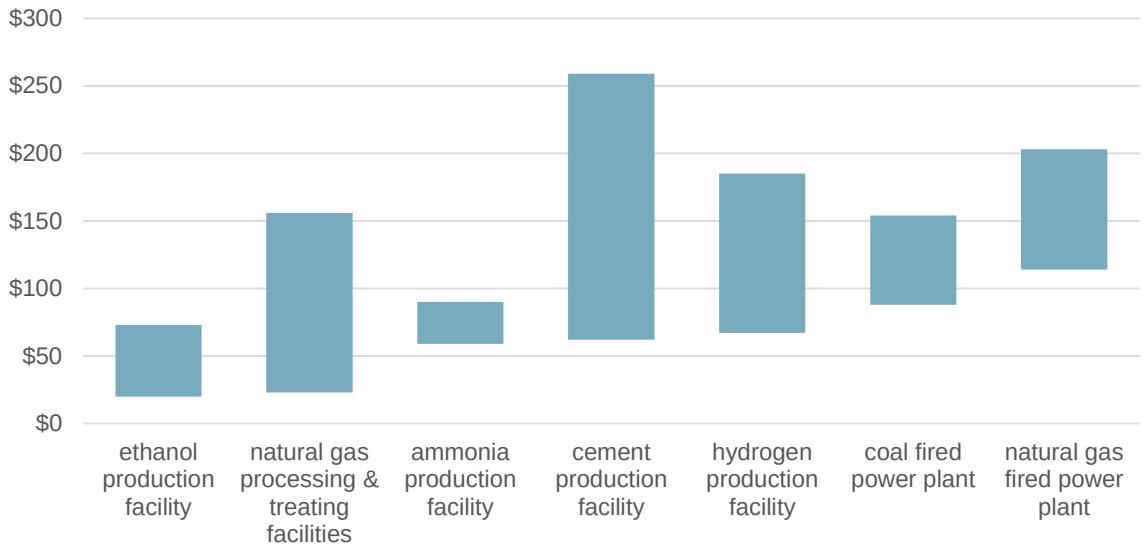
- Design, manufacture, install & operate equipment needed for CO_2 separation
- Operate >1,300 miles of CO_2 pipeline — more than any company in the U.S. with total system capacity of >3 bcfd
- Secure geologic storage of CO_2 via CO_2 enhanced oil recovery (EOR)

Participate with other organizations to advance CCUS policy & technology

Future opportunity to participate in CCUS

- Transportation of very large volumes of CO_2 will be required in order to meet CCUS goals
- Converting other types of pipelines to long haul CO_2 is rarely feasible
- Manufacture & installation of primarily new capture equipment necessary for 45Q eligibility
- EOR is widely viewed to be the best disposition for captured CO_2, but the best EOR potential is distant from most major sources of CO_2

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



Given 45Q credits, CCUS is economic for some ethanol production, natural gas processing, and natural gas treating facilities

Additional technological advancements & government policy could advance CCUS economics for other facilities

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.

APPENDIX

Energy Toll Road

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

	Natural Gas			Products		Terminals			CO_2	
2021B EBDA %[a]	62%			16%		15%			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 80% 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 2021 forecasted net crude oil, propane & heavy NGL (C4+) net equity production.
e) Products terminals not FERC regulated, except portion of CALNEV.

$1.5 Billion Project Backlog as of 12/31/2020

Primarily focused on contracted natural gas opportunities

	DEMAND PULL	SUPPLY PUSH	CAPITAL ($ billion)	ESTIMATED IN-SERVICE	PIPELINE CAPACITY
Supply for U.S. power & LDC demand (TGP, FGT & SNG)	●		$ 0.4	Q1 2021 – 2023	0.6 bcfd
Supply for LNG export (KMLP, NGPL, EPNG)	●		0.3	Q1 2021 – 2022	1.3 bcfd
Gathering & processing (primarily Hiland, Altamont & KinderHawk)		●	0.1	Q1 2021 – 2022	various
Other natural gas	●	●	0.1	Q4 2020 – 2022	~0.3 bcfd
Natural Gas			$ 0.9		
Terminals		●	0.1		
CO_2		●	0.5		
Total backlog			$ 1.5		

~60% of total with 4.7x EBITDA build multiple on average

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

Joint Venture Treatment in Key Metrics

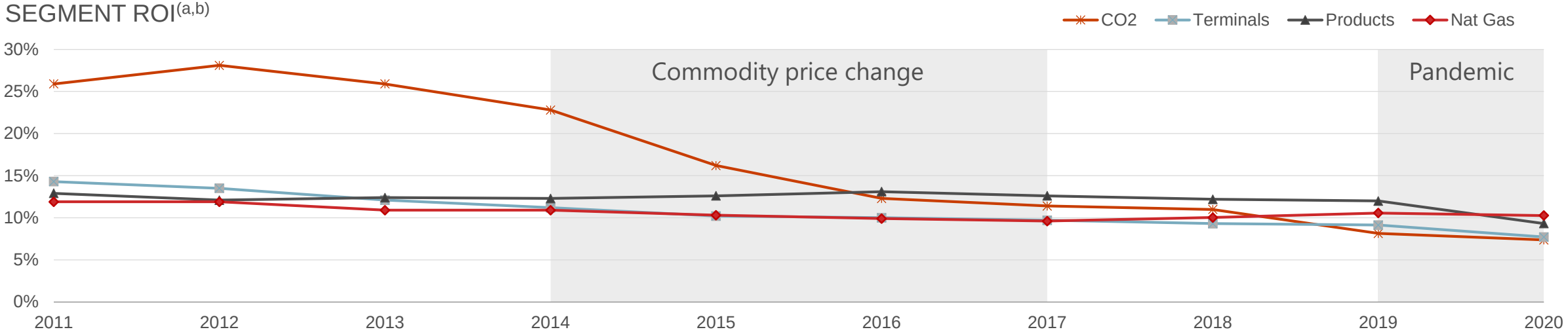
	KM controls & fully consolidates third party portion referred to as noncontrolling interests in financial statements	**KM does not control or consolidate** KM portion referred to as equity investments in financial statements
Example JVs	Elba Liquefaction (51%), BOSTCO (55%)	NGPL (50%), SNG (50%), FGT (50%), MEP (50%), FEP (50%), Gulf LNG (50%)
Net Income	**Includes 100% of JV Net Income** consolidated throughout income statement line items	**Includes KM share of JV Net Income** included in Earnings from Equity Investments
Net Income Attributable to Kinder Morgan, Inc.	**Includes KM share of JV Net Income** excludes Net Income Attributable to Noncontrolling Interests	**Includes KM share of JV Net Income** included in Earnings from Equity Investments
Segment EBDA	**Includes 100% of JV's operating results before DD&A** excludes G&A & corporate charges, interest expense & book taxes Partners' share of earnings are recorded to Noncontrolling Interests on income statement	**Includes KM share of JV Net Income** includes JV DD&A, G&A & interest expenses & book taxes, if any
Adjusted Segment EBDA	**Includes 100% of JV's operating results before DD&A + Certain Items** excludes G&A & corporate charges, interest expense & book taxes Partners' share of earnings are recorded to Noncontrolling Interests on income statement	**Includes KM share of JV Net Income + Certain Items** includes JV DD&A, G&A & interest expenses & book taxes, if any
Adjusted EBITDA	**Includes KM share of JV's (Net Income + DD&A + Book Taxes + Interest Expense + Certain Items)** excludes Net Income Attributable to Noncontrolling Interests	**Includes KM share of JV's (Net Income + DD&A + Book Taxes + Certain Items)** i.e., after subtracting interest expense
Distributable Cash Flow (DCF)	**Includes KM share of JV's (Net Income + DD&A + Book Taxes – Cash Taxes – Sustaining CapEx + Certain Items)** excludes Net Income Attributable to Noncontrolling Interests	**Includes KM share of JV's (Net Income + DD&A + Book Taxes – Cash Taxes – Sustaining CapEx + Certain items)**
Debt	**100% of JV debt included, if any** fully consolidated on balance sheet	**No JV debt included** JV's Adjusted EBITDA contribution is <u>after subtracting</u> interest expense
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.

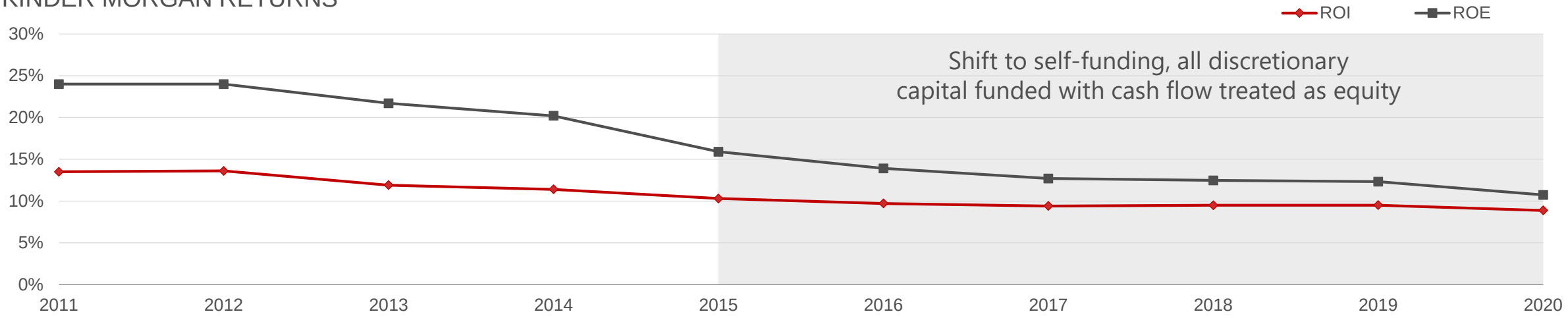
Returns on Invested Capital

Targeted returns for new capital investment are substantially above cost of capital

SEGMENT ROI[a,b]



KINDER MORGAN RETURNS



Notes: See Non-GAAP Financial Measures & Reconciliations for an explanation of return calculations. Reflects KMP (2000-2012), KMP & EPB (2013-2014) & KMI (2015-2020).

a) G&A is deducted to calculate the combined Return on Investment, but is not allocated to the segments & therefore not deducted to calculate the individual Segment ROI.

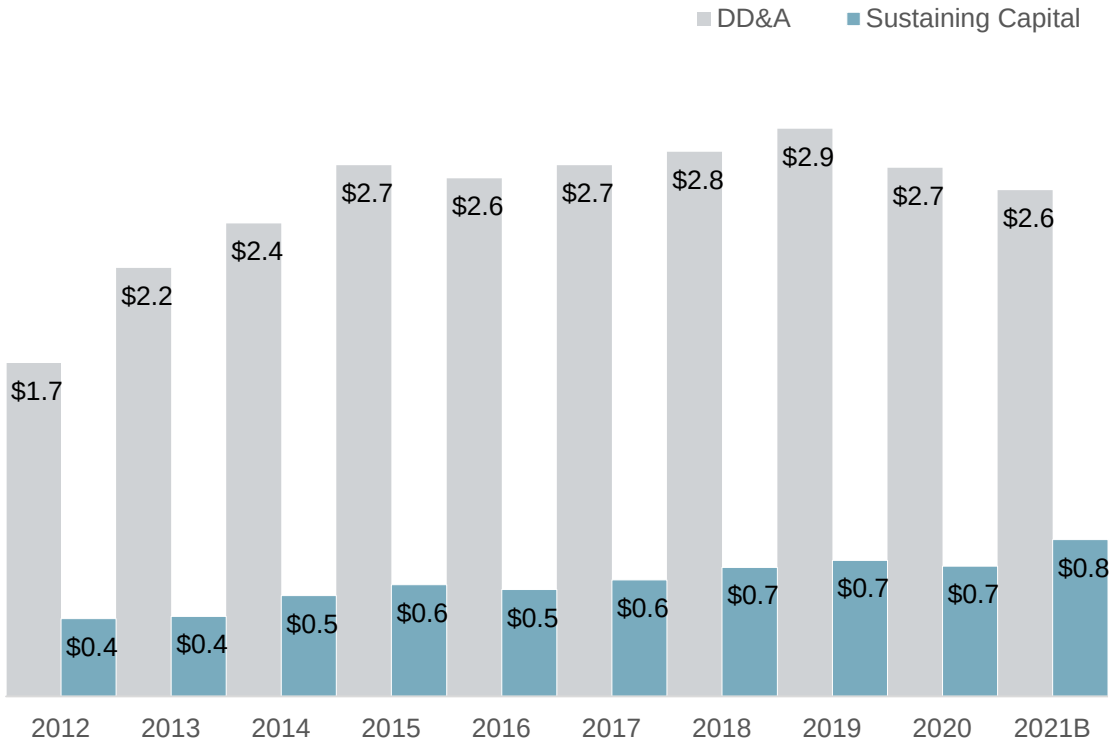
b) Natural Gas segment ROI includes NGPL & Citrus investments since 2015.

Distributable Cash Flow (DCF) versus Net Income

Largest differences easily explainable & reflective of cash earnings

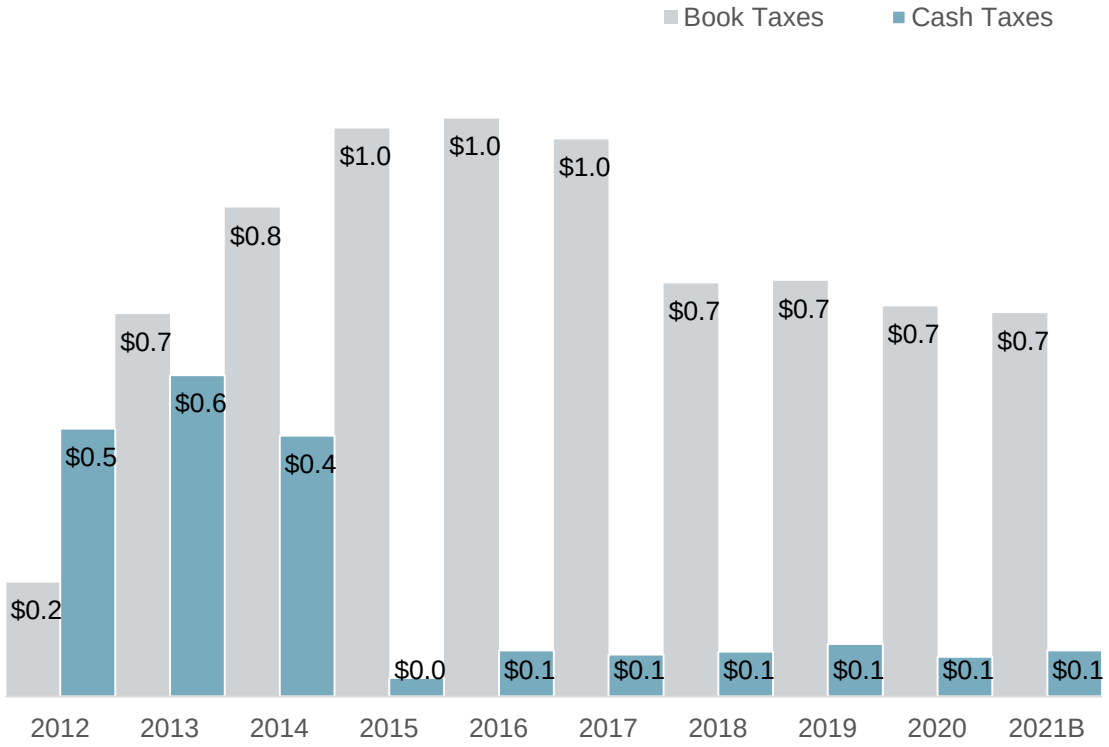
DEPRECIATION EXPENSE VS. SUSTAINING CAPEX[a]

$ billions



BOOK TAX EXPENSE VS. CASH TAXES

$ billions



Our sustaining capex budget is built bottom up by operations based on need & long-term plans

Exemplary safety record demonstrates our spending level on sustaining capex is appropriate

Note: Actuals as presented on the distributable cash flow reconciliation to net income available to common stockholders in SEC Annual Forms 10-K, which includes KM's share of unconsolidated JV amounts.

a) Represents depletion, depreciation & amortization expense (DD&A), including amortization of excess cost of equity investments & JV DD&A. See Non-GAAP Financial Measures & Reconciliations.

Our Pandemic Response

Prioritizing the health of our co-workers & their families while maintaining safe & reliable operations of our assets

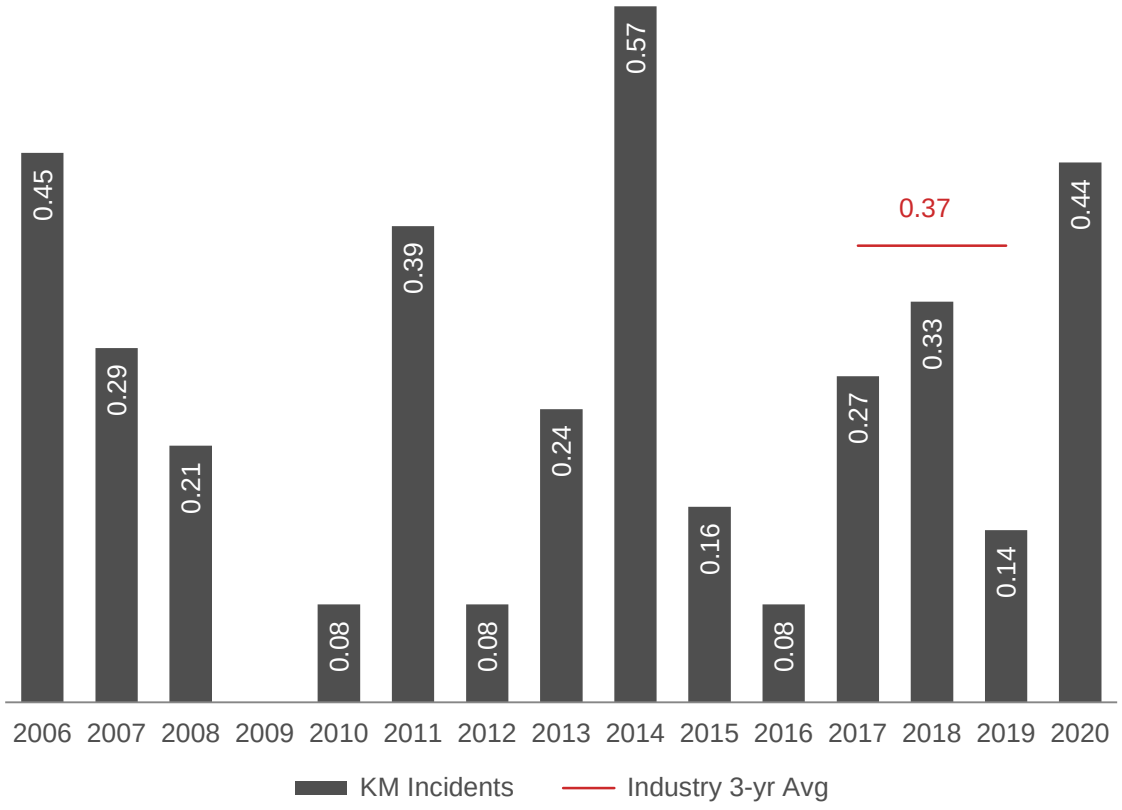
- Leveraging well-established & previously utilized business continuity & pandemic response plans
- Kinder Morgan's Pandemic Preparedness Committee actively monitors both seasonal influenza & COVID-19
  - Regularly adapts response plan to follow guidance from Centers for Disease Control & other health organizations
- Enhanced cleaning protocols
- Telecommuting strategy began on March 16 where possible & continues as we monitor data from the CDC & other health organizations
- Reviewed all tasks that required physical presence to ensure adequate social distance or made alternative arrangements (e.g., critical roles such as field operations, control centers, IT & network operations, etc.)
  - Limiting access to our facilities
  - Implemented screening procedures
  - Distributing PPE, including masks, for a limited number of tasks where social distancing or alternatives were not possible
- In the case of a COVID-19 diagnoses, Human Resources follows established protocol for notifying employees who had direct contact with someone who tested positive to begin mitigation efforts

Delivering energy that is essential to the communities & businesses we serve

Incidents & Releases: Liquids Pipelines

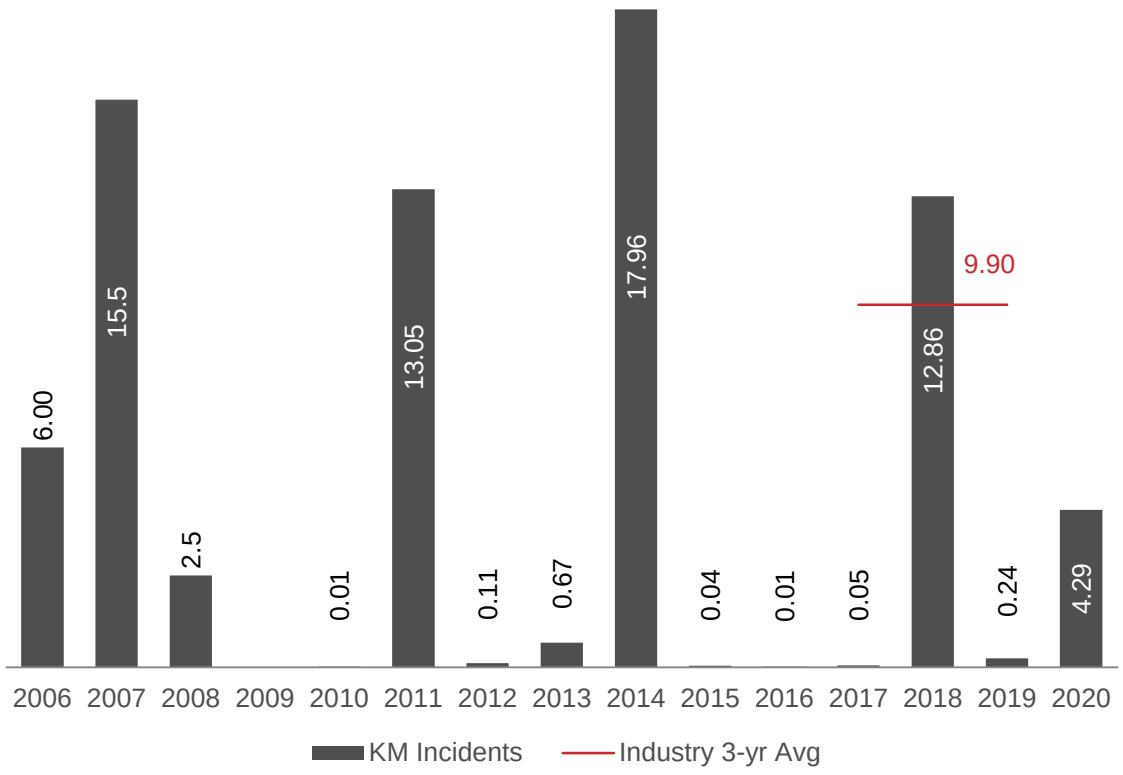
Liquids pipeline right-of-way

INCIDENTS PER 1,000 MILES[a,b]



RELEASE RATE[a,b]

barrels per billion barrel miles



Note: KM totals exclude non-DOT jurisdictional CO_2 Gathering & Crude Gathering for compatibility with industry comparisons.

a) Failures involving onshore pipelines that occurred on the ROW, including valve sites, in which there is a release of the liquid or carbon dioxide transported resulting in any of the following:
- Explosion or fire not intentionally set by the operator
- Release 5 barrels or greater.
- Death of any person
- Personal injury necessitating hospitalization
- Estimated property damage, including cost of clean-up & recovery, value of lost product & damage to the property of the operator or others, or both, exceeding $50,000; not included: natural gas transportation assets

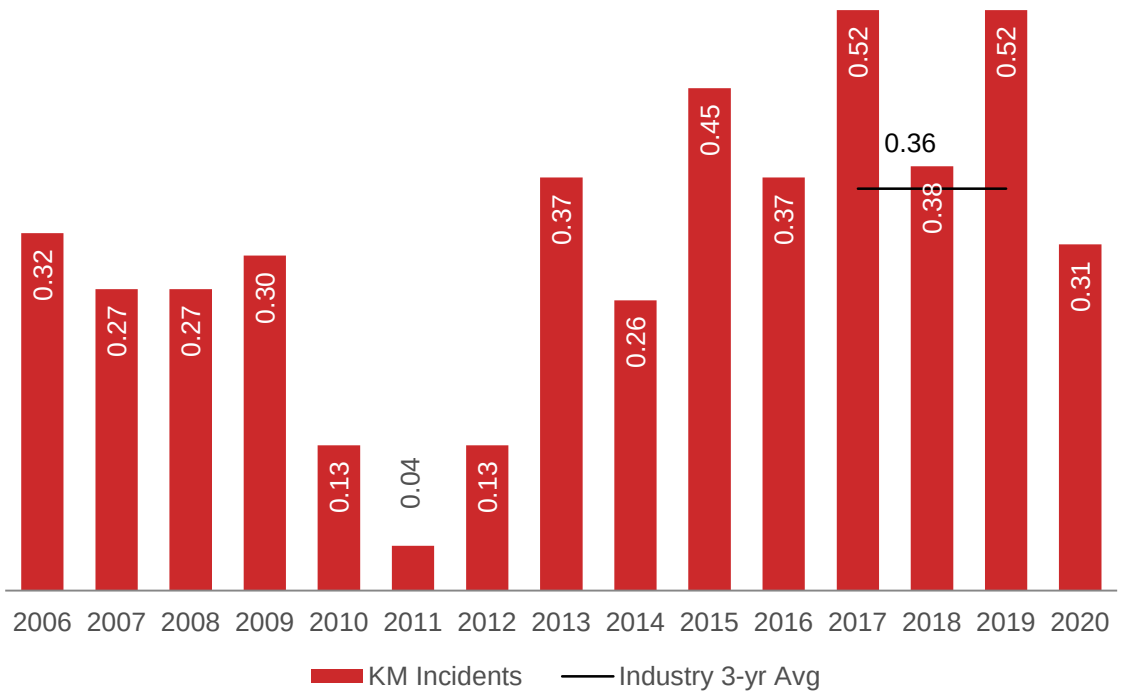
b) 2017-2019 most recent PHMSA 3-year average available.

Incidents & Releases: Natural Gas Pipelines

Natural gas pipeline right-of-way

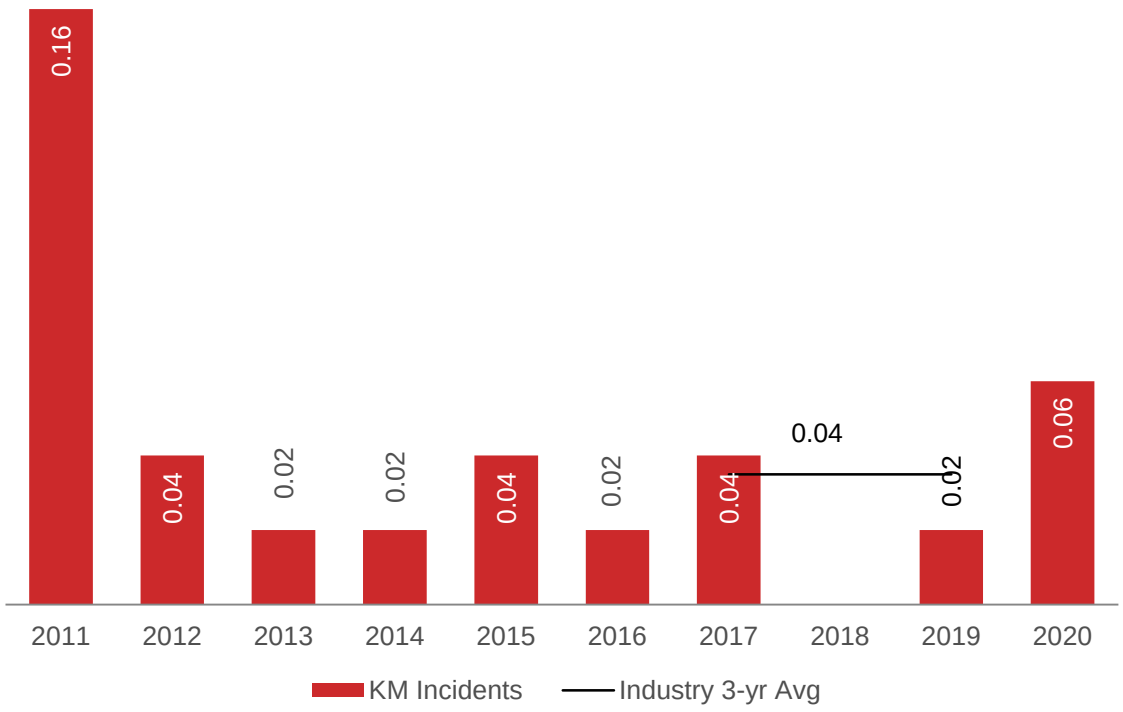
INCIDENTS RATE ALL REPORTABLE INCIDENTS[a,b]

Incidents per 1,000 miles



INCIDENTS RATE ONSHORE RUPTURES ONLY[b,c,d]

Incidents per 1,000 miles



a) Excludes El Paso & Copano assets in periods prior to acquisition (El Paso 5/25/2012, Copano 5/1/2013). An Incident means any of the following events:
- An event that involves a release of gas from a pipeline, or of liquefied natural gas, liquefied petroleum gas, refrigerant gas, or gas from an LNG facility & that results in one or more of the following consequences:
  - A death or personal injury necessitating in-patient hospitalization; or
  - Estimated property damage of $50,000 or more, including loss to the operator & others, but excluding cost of gas lost (2010 & earlier rates include cost of gas lost)
  - Unintentional estimated gas loss of 3 million cubic feet or more
- An event that results in an emergency shutdown of an LNG facility
- An event that is significant, in the judgment of the operator, even though it did not meet the criteria above

b) 2017-2019 most recent PHMSA 3-year average available.

c) Rupture defined as a break, burst, or failure that exposes a visible pipeline fracture surface. Kinder Morgan rupture rates calculated using most current pipeline mileage. Industry rate excludes Kinder Morgan data.

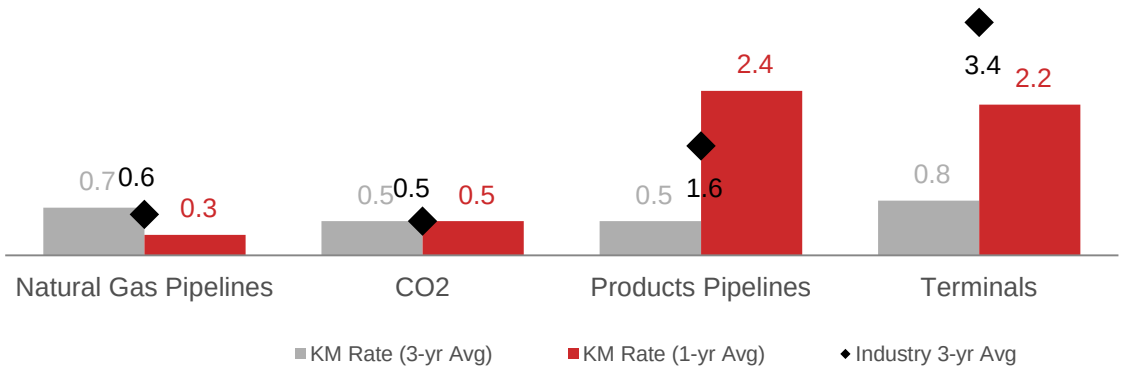
d) All Kinder Morgan ruptures occurred on legacy El Paso facilities prior to the Kinder Morgan acquisition.

Employee Safety Statistics

12-month performance summary as of 12/31/2020

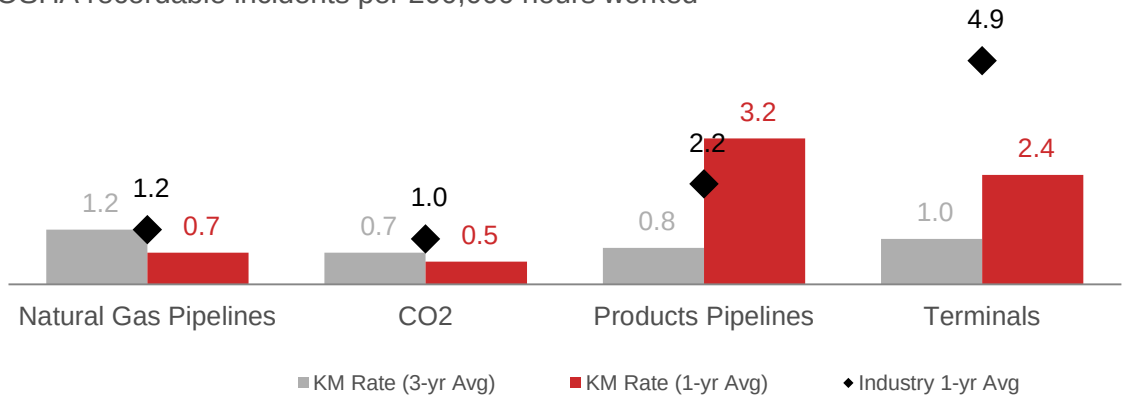
DAYS AWAY, RESTRICTED, OR TRANSFERRED (DART) RATE

Days Away, Restricted or Transferred incidents per 200,000 hours worked



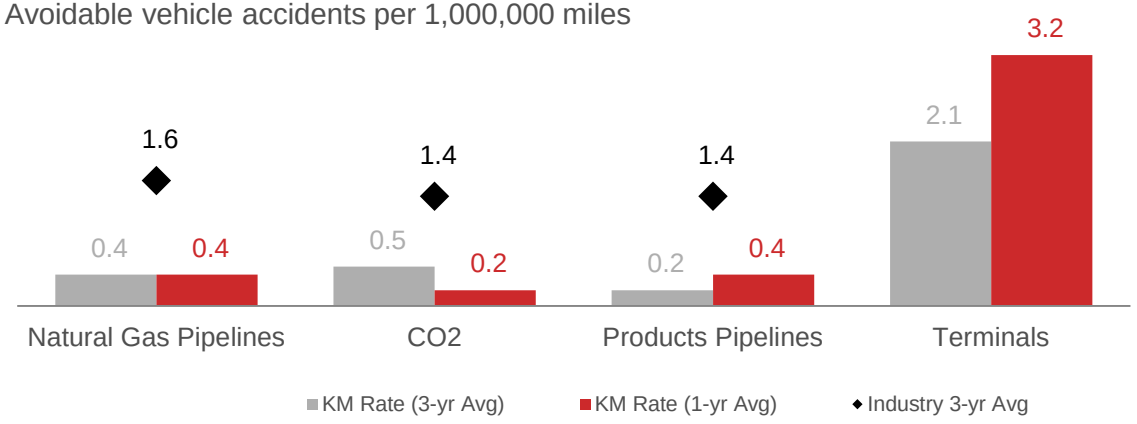
OSHA TOTAL RECORDABLE INCIDENT RATE (TRIR)

OSHA recordable incidents per 200,000 hours worked



VEHICLE INCIDENT RATE[(a)]

Avoidable vehicle accidents per 1,000,000 miles



a) Industry average not available for Terminals.

Non-GAAP Financial Measures & Reconciliations

Defined Terms

Reconciliations for the historical periods

Use of Non-GAAP Financial Measures

The non-GAAP financial measures of Adjusted Earnings and distributable cash flow (DCF), both in the aggregate and per share for each; segment earnings before depreciation, depletion, amortization (DD&A), amortization of excess cost of equity investments and Certain Items (Adjusted Segment EBDA); net income before interest expense, income taxes, DD&A, amortization of excess cost of equity investments and Certain Items (Adjusted EBITDA); Net Debt; Net Debt to Adjusted EBITDA; Project EBITDA; Free Cash Flow; and CO_2 Segment Free Cash Flow are presented herein.

Our non-GAAP financial measures described further 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.

We do not provide (i) budgeted revenue (the GAAP financial measure closest to net revenue) due to impracticality of predicting certain items required by GAAP, including projected commodity prices at the multiple purchase and sale points across certain intrastate pipeline systems. Instead, we are able to project the net revenue received for transportation services based on contractual agreements and historical operational experience; or (ii) budgeted CO_2 Segment EBDA (the GAAP financial measure most directly comparable to 2020 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.

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).

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 be used 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 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 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 assess each 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 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 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.

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 Debt is 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

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.

GAAP Reconciliations

$ in millions

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.

Net Income & Adjusted EBITDA

$ in millions

	2021 Budget	2020 Actual	Change $	Change %
Net income attributable to Kinder Morgan, Inc. (GAAP)	**$ 2,109**	**$ 119**	**$ 1,990**	**1672%**
Total Certain Items	(11)	1,892	(1,903)	(101%)
DD&A and amortization of excess cost of equity investments	2,223	2,304	(81)	(4%)
Income tax expense[(a)]	574	588	(14)	(2%)
JV DD&A and income tax expense[(a)(b)]	419	449	(30)	(7%)
Interest, net[(a)]	1,515	1,610	(95)	(6%)
Adjusted EBITDA	**$ 6,829**	**$ 6,962**	**$ (133)**	**(2%)**

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.

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.

Computation of the Refined Products Contributions to the Products Pipelines Adjusted Segment EBDA

$ in millions

Computation of the Refined Products Contributions to the Products Pipelines Adjusted Segment EBDA	2013	2014	2015	2016	2017	2018	2019	2020
Products Pipelines Segment EBDA (GAAP)	**$602**	**$856**	**$1,106**	**$1,067**	**$1,231**	**$1,209**	**$1,225**	**$977**
Certain Items	72	(100)	(35)	107	(67)	(20)	30	50
Products Pipelines Adjusted Segment EBDA	**$674**	**$756**	**$1,071**	**$1,174**	**$1,164**	**$1,189**	**$1,255**	**$1,027**
Less: Crude & Condensate Contributions to Adjusted Segment EBDA	25	91	381	463	441	446	465	358
Refined Products Contributions to the Products Pipelines Adjusted Segment EBDA	**$649**	**$665**	**$690**	**$710**	**$723**	**$743**	**$771**	**$661**

Explanation of Return Calculations

	Formula	Notes
Segment Return on Investment	Adjusted Segment EBDA less sustaining capex	(a)
	Average Total Investment	(b)
Return on Investment	DCF before interest	(c)
	Average Total Investment	(b)
Return on Equity	DCF (after interest)	(d)
	Average equity	(e)

	Formula	Notes
Calculation of Total Investment:	Gross PP&E	
	Equity Investments (JVs)	(f)
	Goodwill	
	Gross intangibles (excluding amortization)	
	Plus:	
	Asset write-offs / retirements	
	Cumulative environmental reserves	
	Legal reserves / expenditures	(g)
	Cumulative cash spent on asset retirement	(h)
	Minus:	
	Cumulative sustaining capex	
	Assumed liabilities	
	Common control adjustment	(i)
	Cumulative asset retirement costs	(h)
	Proceeds from sold assets / investments	
	Equals:	
	Total Investment	(j)

a) Adjusted Segment EBDA is calculated by adjusting Segment EBDA to more closely tie to cash: (1) our share of JV DD&A is added back and our share of JV sustaining capex is deducted, (2) Express and Endeavor (1H 2014 and prior) pre-tax earnings are subtracted and cash received is added back. Reflects KMP segments (2011-2012), KMP and EPB segments (2013 and 2014) and KMI segments (2015 and after).
b) Total Investment reflects the trailing 5 quarter average.
c) For all years prior to 2015 (prior to the KMI acquisition of KMP, KMR and EPB), this item is defined as the sum of the individual Adjusted Segment EBDA less sustaining capex and G&A. Thereafter, this item is defined as the sum of the individual Adjusted Segment EBDA less sustaining capex, less G&A and cash taxes, plus book taxes deducted at the segment level. Book and cash taxes include KMI's share of unconsolidated C-corp JVs. KML contributions are shown at 100% interest prior to December 2019 sale.
d) For all years prior to 2015 (prior to the KMI acquisition of KMP, KMR and EPB), DCF is defined as limited partners' pretax income before Certain Items and DD&A, less cash taxes paid and sustaining capital expenditures for KMP and EPB, plus KMP's and EPB's share of JV DD&A less KMP's and EPB's share of JV sustaining capital expenditures, less equity earnings plus cash distributions received for Express and Endeavor (1H 2014 and prior), plus the general partner's incentive and the general partner non-controlling interest, as applicable. For 2015 and after, DCF is shown and reconciled in the Appendix: GAAP Reconciliation in this or prior year presentations.
e) Prior to 2016, equity is based on cumulative equity raised inception to date as of each quarter end and then averaged for the year. 2016 and after also include DCF spent to fund growth capital (excluding KML growth capital after its IPO) excluding growth capital funded with debt, if any.
f) Investments are generally calculated based on cumulative contributions and are not increased for earnings or decreased for distributions.
g) Litigation and environmental reserves deducted as Certain Items are added to investment, except for SFPP and CALNEV litigation reserves. For those pipelines, actual legal payments are added to the investment when they are made.
h) For GAAP purposes, the present value of accumulated asset retirement costs are included in gross PP&E; for purposes of this calculation, we decrease our Total Investment / subtract out the accumulated asset retirement costs, and increase our Total Investment / add back any cash actually spent on asset retirement.
i) For assets acquired from Kinder Morgan, Inc. (for example Express, Trans Mountain, TGP and EPNG) or El Paso, Inc. by either KMP or EPB (the MLPs) which represent a transfer of assets between entities under common control and were recorded for financial statement purposes at KMI's carrying value, an adjustment has been made to reflect these assets at the MLPs' purchase price.
j) Through 2019, for Canadian assets / investments, Total Investment is based on acquisition price plus cumulative expansion capital including overhead. The purpose of calculating Total Investment in this manner is to exclude the foreign exchange impact reflected in our GAAP financials which revalue the entire asset balance based on the end of period exchange rate. KML IPO & Divestiture proceeds are deducted as of December 2019.