GROUNDWATER PROTECTION COUNCIL

MODERN OIL & GAS DEVELOPMENT

2023 UPDATE

ACKNOWLEDGMENT TO:

ALL CONSULTING

ACKNOWLEDGMENTS

This update was funded by a U.S. Department of Energy (DOE) Office of Fossil Energy Grant under the National Energy Technology Laboratory (NETL) program, Department of Technologies and Capabilities for Developing Coal, Oil, and Gas Energy Resources. The project was conducted by ALL Consulting (ALL) and was overseen by the Ground Water Protection Council (GWPC). The GWPC Technical Director for this effort was Mr. Mark Layne, PhD, P.E., and the Program Liaison was Ms. Tara Gross. The GWPC also wishes to extend its appreciation to Enverus for providing regional data regarding lateral lengths and water volume usage.

Project Control Statement

This update was performed under my direction and in accordance with good research and analysis principles, including consideration of applicable industry standards and modern engineering practices. This effort was funded by a U.S. Department of Energy, Office of Fossil Energy Grant under the National Energy Technology Laboratory program, Department of Technologies and Capabilities for Developing Coal, Oil, and Gas Energy Resources. The project was conducted by ALL Consulting and was overseen by the Ground Water Protection Council.

The MODERN OIL AND GAS DEVELOPMENT – 2023 UPDATE includes a thorough look at the current conditions of United States onshore oil and natural gas development, including the industry's role in the economy and energy security; the type, manner, and location of oil and gas resources being developed; how development techniques, technologies, methods, and best practices are used to optimize drilling and completion efficiencies; as well as how the industry is being regulated to maximize environmental protection.

LICENSED PROFESSIONAL ENGINEER
J. DAN ARTHUR
19586
OKLAHOMA

12/6/2023

ENGINEER: J.Dan Arthur, P.E., SPEC

SIGNATURE:

DATE: December 6th, 2023

SPE International
SPE Certified Petroleum Engineer 2021

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FOREWARD

The original Primer on Modern Shale Gas Development in the United States was an effort to provide sound technical information on and additional insight into the relationship between natural gas resource development activity and environmental protection, especially water resource management, during the early development stages of this resource.

This 2023 update is intended to share information about the changes and innovation that have occurred over the past decade-plus as shale gas development has matured. Additionally, it outlines many of the current challenges in the industry including water management. Finally, this report also supports GWPC's mission to protect national groundwater resources and promote capacity building in state regulatory agencies by providing the most up-to-date information possible on moder shale gas development.

Water and energy are two of the most basic needs of society. Our use of each vital resource is reliant on and affects the availability of the other. Water is needed to produce energy and energy is necessary to make water available for use. As our population grows, the demand for both resources will only increase. Smart development of energy resources will identify, consider, and minimize potential impacts to water resources.

Shale gas development both requires significant amounts of water and is conducted in proximity to valuable surface and ground water. Hence, it is important to reconcile the concurrent and related demands for local and regional water resources, whether for drinking water, wildlife habitat, recreation, agriculture, industrial or other uses.

Each state has laws and regulations to ensure the wise use of its natural resources and to protect the environment. The GWPC has conducted a separate study to summarize state oil and gas program requirements that are designed to protect water resources. These two studies complement one other and together provide a body of information that can serve as a basis for fact-based dialogue on how shale gas development can proceed in an environmentally responsible manner under the auspices of state regulatory programs. We hope you will find this a useful resource.

- The Ground Water Protection Council

The GWPC is the national association of state ground water and underground injection agencies whose mission is to promote the protection and conservation of groundwater resources for all beneficial uses. One goal of the GWPC is to provide a forum for stakeholder communication on important issues to foster development of sound policy and regulation that is based on sound science.

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Acronyms

API	American Petroleum Institute
BACT	best available control technology
bbls	barrels
Bcf/d	billion cubic feet per day
BEVs	battery-electric vehicles
BLM	Bureau of Land Management
BMPs	best management practices
BPD	barrels per day
BTEX	benzene, toluene, ethylbenzene, and xylenes
CAA	Clean Air Act
CARB	California Air Resources Board
CCA	Candidate Conservation Agreement
CEHMM	Center of Excellence for Hazardous Materials Management
CFR	Code of Federal Regulations
CH_4	methane
CO	Carbon monoxide
CO_2	carbon dioxide
CO_2e	Carbon Dioxide equivalent
CWA	Clean Water Act
E&P	exploration and production
EIA	Energy Information Administration’s
EPA	Environmental Protection Agency
ESA	Endangered Species Act
GHG	greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GWPC	Ground Water Protection Council
HAPs	hazardous air pollutants
HEVs	hybrid-electric vehicles
HVHF	High Volume Hydraulic Fracturing
ICE	internal combustion engine
IOGCC	Interstate
Oil and Gas Compact Commission	
Km	kilometers
LBNL	Lawrence Berkeley National Laboratory
LDV	light-duty vehicle
LNG	liquefied natural gas
M	magnitude
MBPD	thousand barrels per day
Mcf	thousands of cubic feet
MMBPD	Million barrels per day
MWh	megawatt hour
MZF	modified zipper fracturing
N_2O	nitrous oxide
NAAQS	National Ambient Air Quality Standards
NESHAP	National Emission Standards for Hazardous Air Pollutants
NETL	National Energy Technology Laboratory
NMFS	National Marine Fisheries Service
NOx	nitrogen oxides
NPDES	National Pollutant Discharge Elimination System
NPT	non-productive time
NSPS	New Source Performance Standards
NSR	New Source Review
NWPR	Navigable Waters Protection Rule
O3	Ozone
Pb	Lead
PHEVs	plug-in hybrid-electric vehicles
PM	Particulate Matter
PW	produced water
RGGI	Regional Greenhouse Gas Initiative
SCITIS	Stanford Center for Induced and Triggered Seismicity
SO_2	Sulfur dioxide
SW	Slick Water
SWD	saltwater disposal well
Tcf	trillion cubic feet
TD	total depth
U.S.	United States
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish and Wildlife Service
VOC	Volatile Organic Compounds
WOTUS	Waters of the United States

1 Introduction

1.1 Purpose of Primer Update

In the mid-2000s, the oil and gas industry, and energy industry as a whole, underwent a major shift as the emergence of shale gas development brought increased levels of drilling activity to existing oil and gas development areas as well as to new areas that were not previously explored nor familiar with this type of activity. This intensified exploration garnered a renewed environmental focus, which generated questions about technologies being utilized to develop the resources, including hydraulic fracturing and horizontal drilling. In areas of the country experiencing hydrocarbon development for the first time, residents and regulators questioned the environmental and socio-economic impacts, and whether appropriate regulatory structures were in place to ensure responsible development.

In response to these concerns, the Ground Water Protection Council (GWPC) prepared a document that would serve as a technical reference, describing how shale gas resources were being developed, measures being taken to reduce adverse impacts, and the various federal, state, and local laws or regulations governing the industry. This document, titled "Modern Shale Gas Development in the United States: A Primer" (The Primer), was first published in 2009 and became an important reference for law makers, industry representatives, and citizens to better understand hydrocarbon resource development.

The oil and gas resources developed today, and the manner in which they are developed, are much different than when The Primer was originally published. The industry continues to develop and evaluate technologies, methods, and best practices to optimize drilling and completion efficiencies, environmental stewardship, and productive capacities. Additionally, in response to stakeholder demands, E&P companies have pivoted from an "annual growth of reserves" approach and adopted a capital discipline of developing resources within their individual company capital capacity. Similarly, there have been noteworthy changes in the way oil and gas development is regulated and improvements in the mitigation of environmental and socio-economic effects.

The purpose of this document is to update stakeholders on the current conditions of United States (U.S.) onshore oil and natural gas development, including the industry's role in the U.S. economy and energy security; the type, manner, and location of oil and gas resources being developed; how development techniques, technologies, and locations have changed over time; and how the industry is being regulated to maximize environmental protection. GWPC engaged ALL Consulting to assess and distill the available information from the exploration and production (E&P), regulatory, financial, and technical communities in the development of this report update consistent with the original Shale Primer also written by ALL Consulting in 2009.

1.2 Primer Update Format

This Primer update retains the primary structure of the original report and covers seven of today's most prominent onshore development regions, including operational and economic factors affecting change such as refinement and expansion of hydraulic fracturing and horizontal drilling technologies. The laws and regulatory framework governing onshore development have also evolved to better control water and waste management, and air emissions at every stage of a well's life cycle. As such, many sections of this update will examine adverse environmental impact mitigation through such mechanisms as more robust and frequent regulatory reporting.

The areas of modern oil and gas development mirror those discussed in GWPC's recent Produced Water Report – 2023 Regulations and Practices Update, which focused on notable regulatory, technical, and operational changes in the produced water (PW) management cycle for seven of the most prominent onshore oil and gas development regions (see **Figure 1)**:

1. **Permian** (Midland and Delaware Basins) – west Texas and southeast New Mexico
2. **Eagle Ford** – Texas (central and south Texas)
3. **Appalachian** (Utica and Marcellus Basins) – Pennsylvania, Ohio, West Virginia
4. **Bakken** – North Dakota, Montana
5. **Mid-Continent** – Oklahoma, southern Kansas, and north Texas
6. **Rocky Mountain** – Colorado, Wyoming, Utah, and northwest New Mexico
7. **Haynesville** – Arkansas, Louisiana, and northeast Texas

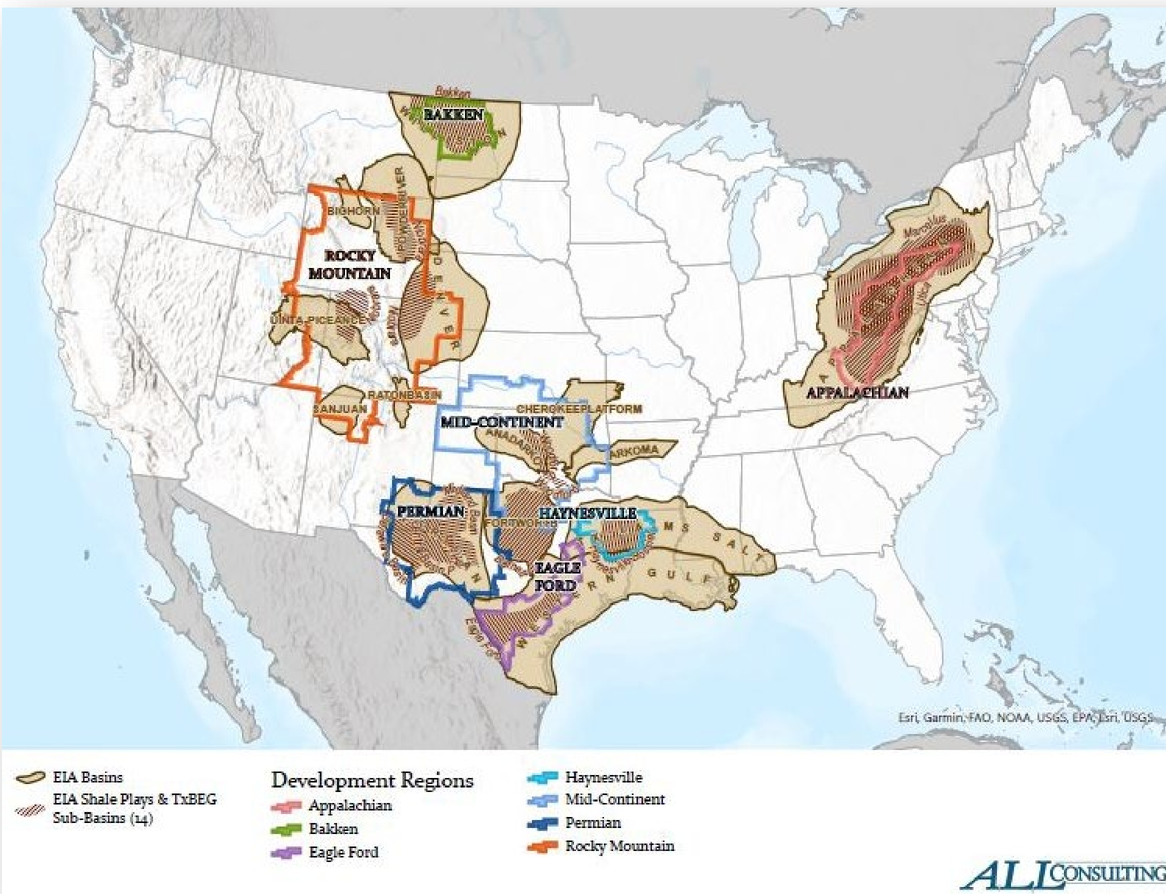

Figure 1: Seven Most Prominent Oil and Gas Development Regions in the Continental U.S.

Unlike The Primer, which presented data for individual onshore shale basins, the Primer Update considers the particular exploration and production methods of broader development regions. Larger operators with assets in multiple regions recognized they could simplify operations and realize capital efficiency by homogenizing drilling and hydraulic fracturing techniques among regions with similar geology. This, in turn, led to the preferential use of slick water fracking, representing a meaningful change from the initial fresh water / cross-link gel frac-fluid approach. Slick water frac-fluids are the predominant method used within each development region today. However, there are exceptions to this trend, as some developers prefer other methods.

1.3 Role of Oil and Gas in the U.S.

Refined crude oil and natural gas are the feedstocks used for many modern materials including plastics, fertilizers, clothing, and even the wind turbines and solar panels on the horizon of America's renewable energy future. Hydrocarbons are the foundational molecules in everyday items such as surgical gloves, medications, seat belts, air bags, carbon fiber, agricultural fertilizers, asphalt roof shingles, plastic insulation of refrigerators, etc.[1] Besides finished fuels such as gasoline and diesel for cars, trucks and cargo ships, natural gas fuels power plants that charge electric vehicles and everyday necessities such as heating and air conditioning, refrigeration, illumination, and countless industrial processes.[2]

Natural gas also plays a critical role in U.S. energy security, serving as a lower emission source of electric power generation; as a reliable stop-gap energy source for renewable power; as the raw material to produce low-carbon hydrogen and agricultural fertilizers; and as the basis for the continued ramp up in liquified natural gas (LNG) exportation. Natural gas is abundant in the U.S.

1.3.1 Domestic Energy Consumption

The Energy Information Administration's (EIA) 2022 Annual Energy Outlook base case model projects energy consumption to grow through 2050 due to population and economic growth outpacing industry efficiency gains. Oil and natural gas will continue being consumed in the greatest volumes, while coal consumption will steadily decline during that time.[3] According to the EIA, the U.S. consumed 18,684.483 thousand barrels per day (MBPD) of oil in 2021, an increase of 5.5 percent when compared to the 17,992.622 MBPD it consumed in 2011. Natural gas consumption increased nearly 25 percent over the same interval, growing from 24.48 trillion cubic feet (Tcf) in 2011 to 30.66 Tcf in 2021.[4] On a percentage basis, total U.S. petroleum consumption by major end-use sectors in 2021 was:[5] (see **Figure 2)**[6]

- Transportation: 67.2%
- Industrial Purposes: 26.9%
- Residential Usage: 2.8%
- Commercial Purposes: 2.6%
- Electric Power: 0.5%

[1] U.S. DOE, 2020. U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life (DOE), September 2020.
[2] ibid
[3] U.S. EIA, 2022. Annual Energy Outlook 2022, March 3, 2022, accessed on September 19, 2022, at https://www.eia.gov/outlooks/aeo/narrative/production/sub-topic-01.php
[4] U.S. EIA, Natural Gas Explained, Where our Natural Gas Comes From, accessed September 20, 2022 at https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php. Natural Gas Consumption, Dry Production, and Net Exports, 1950-2022 chart.
[5] U.S. EIA, Oil and Petroleum Products Explained, Use of Oil, accessed on September 20, 2022 at https://www.eia.gov/energyexplained/oil-and-petroleum-products/use-of-oil.php
[6] Source: U.S. EIA Monthly Energy Review (April 2022) Tables 3.5, 3.7a, 3.7b, and 3.7c.

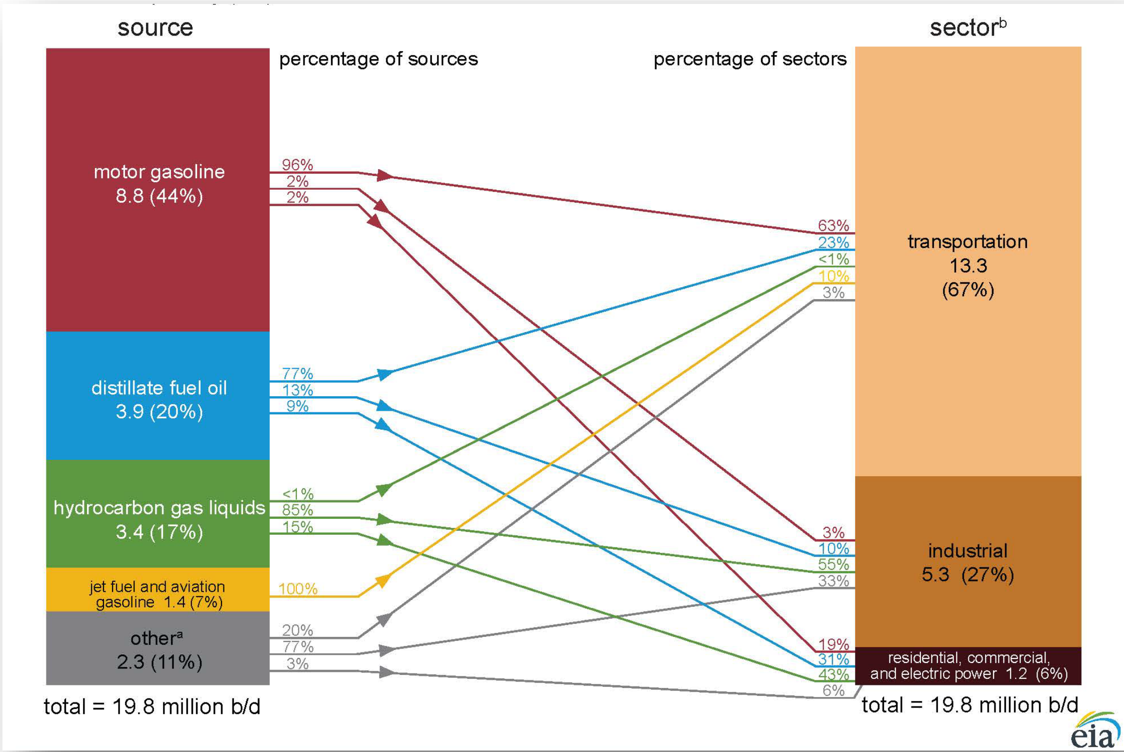

Figure 2: U.S. Petroleum Products Consumption by Source and Sector, 2021 (MMBPD)

The chart in **Figure 2** does not show hydrocarbon production, nor the losses incurred during production. EIA assumes petroleum consumption is equal to petroleum production.[7] While the generation and consumption of renewable energy from wind and solar will slowly change these percentages, EIA estimates oil, natural gas, and natural gas liquids will constitute almost 70 percent of domestic energy consumption by 2050, a 14 percent increase from 2021 numbers.[8]

1.3.2 Oil Production Trends

Peak oil theory is the idea that the global production of oil will reach a peak and then decline. This theory was first proposed by M. King Hubbert, a geologist, in 1956. Hubbert predicted U.S. oil production would peak in the 1970s, and this prediction was believed valid at the time.[9] The horizontal hydraulic fracturing revolution challenged that theory and led to a significant increase in oil and gas production, taking proved reserves of crude oil and lease condensate in 2008 from approximately 21 billion bbls to nearly 45 billion bbls in 2021.[10] Concurrently, proved reserves for natural gas also

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[7] ibid

[8] U.S. EIA, Oil and Petroleum Products Explained, accessed on September 22, 2022, at https://www.eia.gov/energyexplained/oil-and-petroleum-products/use-of-oil.php

[9] Peebles, Torren. "Development of Hubbert's Peak Oil Theory and Analysis of Its Continued Validity for U.S. Crude Oil Production." The Department of Earth & Planetary Sciences, May 5, 2017. https://earth.yale.edu/sites/default/files/files/Peebles_Senior_Essay.pdf.

[10] U.S. EIA, U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2021, accessed July 10, 2023, at https://www.eia.gov/naturalgas/crudeoilreserves/

increased over this same time span, growing from approximately 255 Tcf in 2009 to near 620 Tcf in 2021.

Since 2009, the U.S. has increased crude oil production by over 200 percent, growing the amount from ~5.5 million bbls per day (MMBPD) in 2009 to an estimated 11.6 MMBPD in 2021.[11] The horizontal hydraulic fracturing revolution has not completely disproved peak oil theory; shale gas reserves are finite and will eventually be depleted. The horizontal hydraulic fracturing revolution has lent complexity to peak oil theory and has shown innovative technologies can lead to the discovery and production of new oil and gas reserves.

Today, the U.S. is producing more oil and gas from unconventional development in shale formations than from conventional formations. This is illustrated in **Figure 3,** which shows a net increase in shale gas production and net decrease in conventional production from conventional formations over this period.[12]

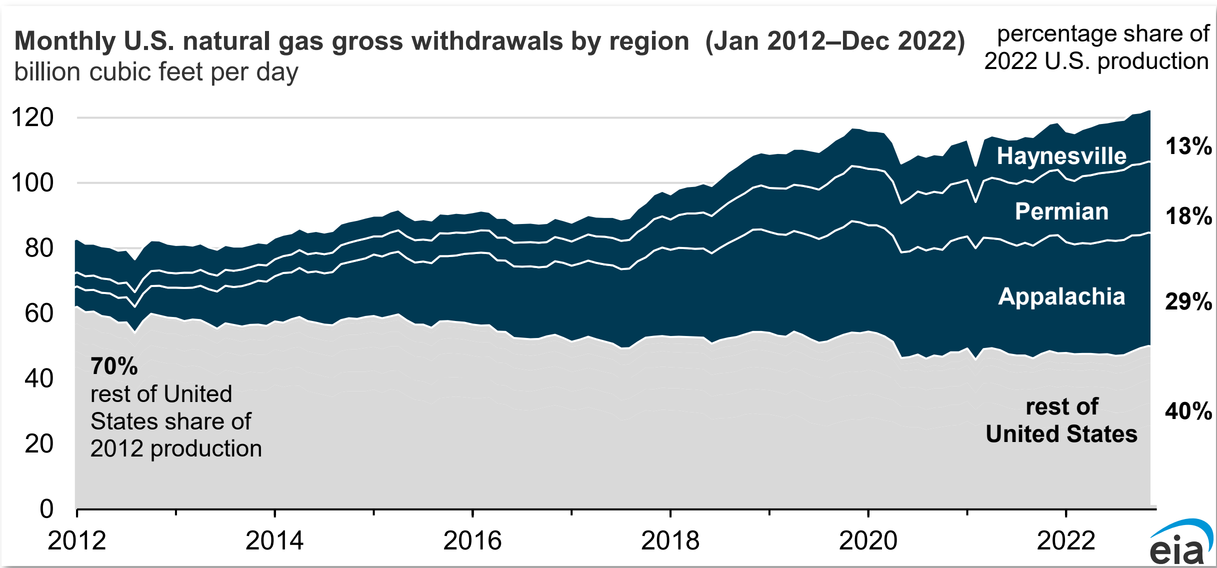

Figure 3: Monthly U.S. Natural Gas Gross Withdrawals by Region

1.3.3 Still Fueling Transportation

Despite electric vehicles gaining market share, gasoline continues to be the most common transportation fuel and remains the dominant light-duty vehicle (LDV) fuel. LDVs accounted for 54 percent of the energy consumed in the U.S. transportation market in 2021.[13] This share is projected to fall in the future. Numerous factors including charging infrastructure, auto-manufacturing conversion rates, legislative incentives, cost of ownership economics, and vehicle reliability, each contribute to the rate at which this transition occurs. During the interim, LDV energy consumption is expected to generally decrease. Concurrently, sales of conventional motor gasoline vehicles are expected to decrease as sales

[11] U.S. EIA, U.S. Crude Oil Production – Historical Chart accessed on July 10, 2023, at https://www.macrotrends.net/2562/us-crude-oil-production-historical-chart

[12] U.S. EIA, U.S. Natural Gas Production Grew by 4% in 2022, accessed on July 10, 2023, at https://www.eia.gov/todayinenergy/detail.php?id=56000

[13] U.S. EIA, Annual Energy Outlook 2022, Motor gasoline remains the most prevalent transportation fuel despite electric vehicles gaining market share, accessed July 11, 2023 at https://www.eia.gov/outlooks/aeo/narrative/consumption/sub-topic-01.php

of battery-electric vehicles (BEVs), hybrid-electric vehicles (HEVs), and plug-in hybrid-electric vehicles (PHEVs) increase. The EIA is projecting the combined sales of internal combustion engine (ICE) LDVs will decrease from 92 percent in 2021 to 79 percent in 2050.[14]

1.3.4 Electricity Generation per Energy Source

As of 2019, more than a third of the country's electricity was generated by natural gas (35 percent), as illustrated in **Figure 4**.[15] Natural gas, along with renewable sources, such as hydropower, wind, geothermal, and solar, have contributed to U.S. electric power generation at an increasing rate over the past decade. The federal government's focus on controlling greenhouse gas emissions (GHG) has promoted the progressive transition to natural gas for power generation from coal, thereby reducing domestic and global carbon dioxide (CO_2) emissions.

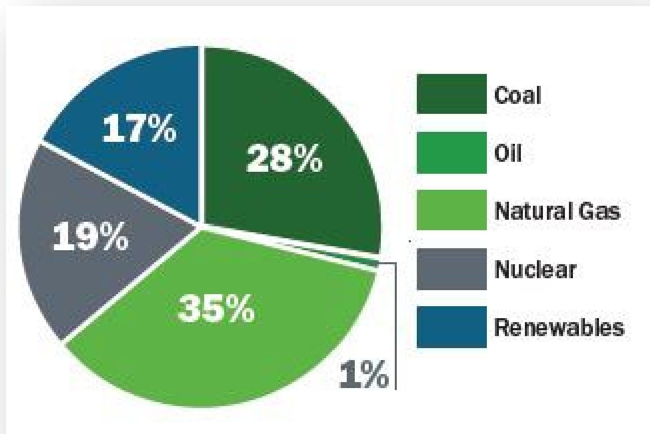

Figure 4: U.S. Electricity Generation

According to the EIA, natural gas could represent greater than 40 percent of energy generation capacity by 2050.[16] Nevertheless, the impact of burning natural gas for power generation is already measurable. The DOE estimates CO_2 emissions per megawatt-hour (MWh) have been reduced by over 23 percent since 2010.[17] Utility-scale power generation from renewables is the country's fastest-growing sector despite the fact power generation from renewable sources is intermittent and dependent on weather patterns and sun cycles. Until battery technology and electric grid dynamics are capable of storing a larger portion of the power generated by renewables, natural gas will continue to fill the gap when renewables sources are insufficient.

In 2010 renewables accounted for 10 percent of power generation, but by 2022, power generation from renewables had grown to 21 percent, with the increase primarily driven by wind and solar generating capacity.[18] This increased capacity surpassed coal and nuclear generation, as both sources saw

[14] ibid

[15] U.S. DOE, Office of Oil & Natural Gas and National Energy Technology Laboratory, U.S. Oil and Natural Gas – Providing Energy Security and Supporting Our Quality of Life, accessed on January 16, 2023 at https://www.energy.gov/fecm/articles/natural-gas-benefits-report

[16] U.S. EIA, Energy-related carbon dioxide (CO2) emissions dip through 2035 before climbing later in the projection years, accessed on June 14, 2023 at Annual Energy Outlook 2022 Narrative (eia.gov)

[17] U.S. DOE, 2020. U.S. Oil and Natural Gas: Providing Energy Security and Supporting Our Quality of Life (DOE), September 2020.

[18] U.S. EIA, Renewable Energy Consumption and Electricity Preliminary Statistics 2010, accessed on July 13, 2023 at https://www.eia.gov/renewable/annual/preliminary/#:~:text=Renewable%20energy%20provided%2010%20percent,billion%20kWh%20(Table%203).&text=U.S.%20total%20net%20generation%20increased,percent%20between%202009%20and%202010.

reductions in 2022 to 20 and 18.7 percent, respectively.[19] In that same period, natural gas generation increased to 39 percent of the national power generation.

1.3.5 Energy Provider to the World

In 2019 the U.S. became a net energy exporter[20] and in 2022 the world's leading LNG exporter.[21] Total American exports of LNG in 2019 were about 4.66 Tcf to some 38 different countries around the world, and average daily exports in the first six months of 2022 were 11.2 billion cubic feet per day (Bcf/d). The EIA estimates annual LNG exports could reach 12 Bcf/d by 2050. As LNG export capacity grows with the construction of new facilities, international demand for LNG is expected to trend higher, and forecast to put upward pressure on LNG market prices. Indeed, growth in demand for natural gas exports will directly drive increased domestic natural gas production.[22] By 2050, the domestic production-to-consumption ratio is expected to widen to about 25 percent, with the bulk of the excess natural gas liquefied and exported.[23]

1.3.6 Increasing Reserves

As companies evaluate further complex geologic and engineering data to understand potential in-place hydrocarbon resources, they estimate how much is recoverable under certain economic and operational conditions. These volumes are called *proved* reserves[24]. Such reserves are dynamic and change annually because of newly discovered fields, in-depth appraisal of previously delineated fields, drops in existing reserves from continuous production, fluctuations in market prices and operating costs, and deployment of new technology.[25]

Between 2009 and 2019, proved reserves of U.S. crude oil and lease condensate increased from 22.3 billion to 47.1 billion barrels, with the top three states being Texas, New Mexico, and Alaska.[26] During the same period, U.S. total natural gas proved reserves increased from 283.9 to 494.4 Tcf. Alaska saw the largest increase, trailed by Texas and New Mexico.[27] Generally, upward trends in oil reserves in Texas were attributable to play extensions and discoveries in the Permian and Delaware Basins.[28] Additions to U.S. natural gas proved reserves mostly occurred in shale play extensions and discoveries in the historically prolific Delaware Basin (Wolfcamp/Bone Spring plays), and the ever-expanding Marcellus in

[19] U.S. EIA, Renewable generation surpassed coal and nuclear in the U.S. electric power sector in 2022, accessed July 12, 2023 at https://www.eia.gov/todayinenergy/detail.php?id=55960

[20] U.S. EIA, U.S. Energy Facts Explained, accessed on June 24, 2023 at https://www.eia.gov/energyexplained/us-energy-facts/imports-and-exports.php#:~:text=The%20United%20States%20became%20a,position%20in%202020%20and%202021.

[21] U.S. EIA, Today in Energy – The United States become the World's largest LNG exporter in the first half of 2022, accessed on March 17, 2023 at https://www.eia.gov/todayinenergy/detail.php?id=53159

[22] U.S. EIA, 2022. Annual Energy Outlook 2022, March 3, 2022, accessed on September 19, 2022, at https://www.eia.gov/outlooks/aeo/narrative/production/sub-topic-01.php

[23] ibid

[24] In the oil and gas sector, proved reserves have a reasonable certainty of being recovered, whereas recoverable oil reserves are the amount of oil that can reasonably be recovered given current technical and economic conditions.

[25] U.S. EIA, Natural Gas, 2022. U.S. Crude Oil and Natural Gas Proved Reserves, Year-end 2021, accessed on October 5, 2022 at https://www.eia.gov/naturalgas/crudeoilreserves/

[26] ibid

[27] ibid

[28] ibid

the Appalachian Basin, where production volume was the nation's highest.[29] **Table 1** provides the natural gas proved reserves for the shale plays within the Development Regions for 2020 to 2021.[30]

Table 1: U.S. Shale Plays Natural Gas Proved Reserves, 2020-2021, Trillion Cubic Feet

Development Region	Shale Play	State(s)	2020 Proved Reserves	2021 Proved Reserves	2020-21 Percent Change
Appalachian	Marcellus & Utica/Pt. Pleasant	Ohio, Pennsylvania, and West Virginia	156.8	176.5	12.56
Bakken	Bakken/Three Forks	Montana and North Dakota	8.6	11.4	32.56
Eagle Ford	Eagle Ford	Texas	22.3	30.0	34.53
Haynesville	Haynesville/Bossier	Louisiana and Texas	44.8	56.2	25.45
Mid-Continent	Barnett/Fayetteville and Woodford	Arkansas, Oklahoma, and Texas	30.5	39.5	29.51
Rocky Mountain	Niobrara	Colorado and Wyoming	2.2	5.2	136.36
Permian	Wolfcamp/Bone Spring	New Mexico and Texas	52.5	75.0	42.86
Total			**317.7**	**393.8**	**23.95**

[29] ibid

[30] Sources: U.S. EIA, Form EIA-23L, Annual Report of Domestic Oil and Gas Reserves, 2019 and 2020

2 Development Regions

Fluctuation in development activity for each of the seven regions discussed in this report is attributable to changes in workforce levels, social and regulatory pressures, and commodity prices. **Figure 5** shows these fluctuations by region and the overall drop in the quantity of oil and gas wells drilled in each since 2014. The Permian region has seen the highest level of activity since 2010. While it is still the most prolific natural gas region in the U.S. in terms of gross production, completions per year in the Appalachian region began declining after 2015.

The future of crude oil production in the U.S. will come from tight oil plays – often shale or tight sandstone – such as those in the Permian region of Texas and New Mexico and the Bakken Region of North Dakota and Montana. Future natural gas production will originate from the shale gas plays of the Appalachian and Haynesville regions, along with large volumes of associated gas from tight oil plays. In addition to these unconventional reservoirs, mature conventional oil and natural gas reservoirs will continue to contribute to the nation's energy supply.

A limited number of fundamental technical advances steered the extraordinary expansion of U.S. oil and natural gas production from these regions over the past couple of decades. Such advances will need to persist to provide Americans with abundant, reliable, and secure sources of energy.

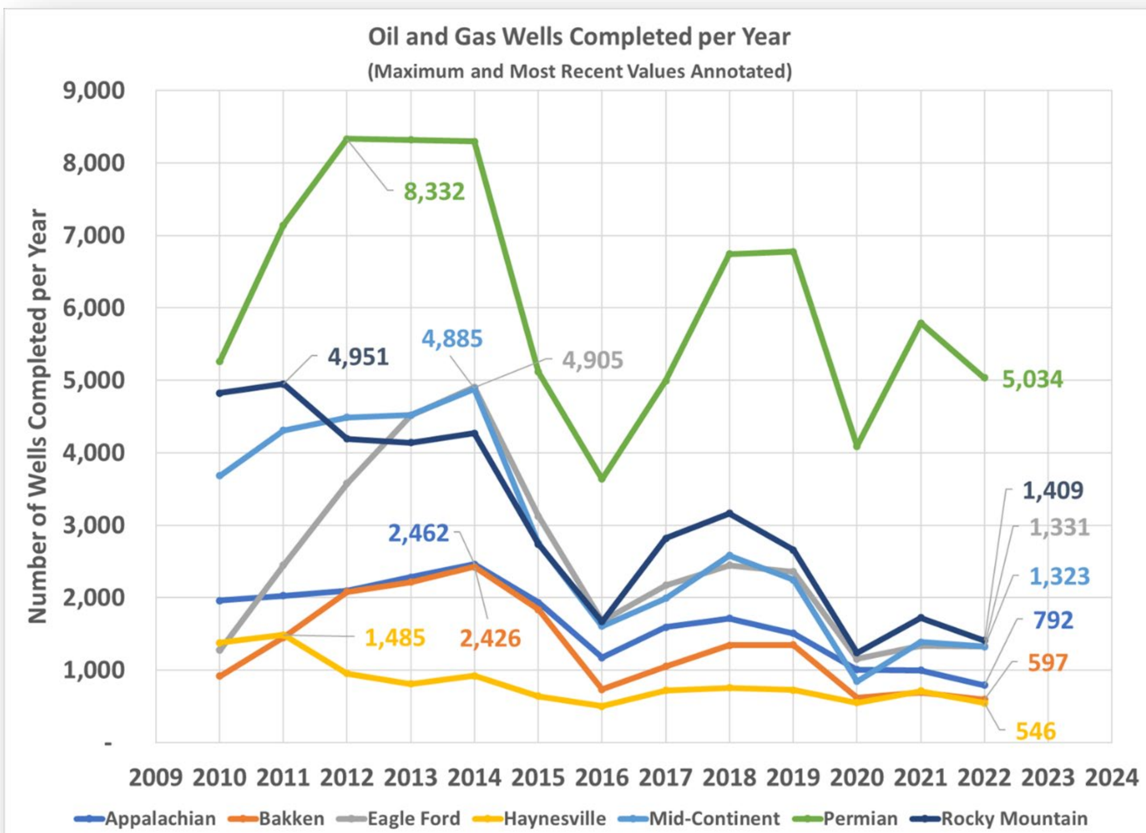

Figure 5: Oil & Gas Wells Completed per year per Development Region

2.1 Permian Region

The Permian region includes the Delaware and Midland basins and the Central Basin Platform, which encompasses portions of New Mexico and Texas (**Figure 6**). The play within this region includes the Permian-aged Wolfcamp, Bone Spring, Spraberry, and Avalon formations, which feature both oil and natural gas plays over a total area of approximately 75,000 square miles. Depths of producible plays range from 2,000 to 11,000 feet below surface.[31] Since 2011, the average length of horizontal laterals has increased from ~3,600 feet to ~9,200 feet (~156%).[32] Formation thickness varies from 1,300 to 1,800 feet, and as of January 2023, there were over 350 drilling rigs active in the region.[33]

The Permian is the second-largest U.S. natural gas producing region, accounting for ~18 percent of U.S. annual production. In 2022, gross natural gas withdrawals there rose by 2.6 Bcf/d, averaging 21.0 Bcf/d.[34] Unlike other regions, natural gas production growth is primarily associated gas from exploration for oil resources.

Since 2011 when horizontal drilling coupled with hydraulic fracturing began in the region, a total of ~79,500 wells have been drilled and completed, with cumulative oil production in excess of 9,747,950,000 barrels and cumulative gas production of nearly 33,546,550,000 thousand cubic feet (mcf).[35]

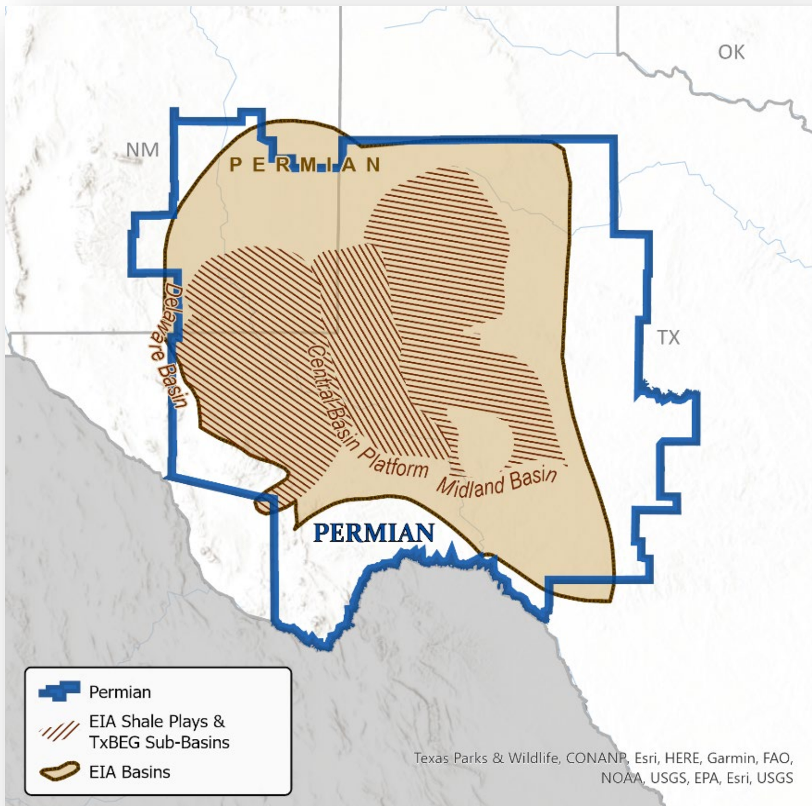

Figure 6: Permian Development Region

[31] U.S. Energy Information Administration (EIA). February 2020. Permian Basin Part 1 – Wolfcamp, Bone spring, Delaware Shale Plays of the Delaware Basin. https://www.eia.gov/maps/pdf/Permian-pl_Wolfcamp-Bonespring-Delaware.pdf (accessed July 11,2022).

[32] ALL work product using Enverus data.

[33] Baker Hughes Rig County – 01/27/2023, https://bakerhughesrigcount.gcs-web.com/na-rig-count (accessed February 2, 2023).

[34] U.S. EIA, U.S. Natural Gas Production Grew by 4% in 2022, accessed on July 11, 2023, at https://www.eia.gov/todayinenergy/detail.php?id=56000

[35] ALL work product using Enverus data.

2.2 Bakken Region

The Bakken region includes the Williston Basin, which lies below parts of Montana and the Dakotas. The plays in this region are the Devonian, Mississippian Bakken, and the Three Forks formations, all of which produce both oil and gas (**Figure 7**). The region was first developed in 1953 and is comprised of approximately 13,500,000 acres.[36] The depths of production range from 6,500 to 10,500 feet, and the formation thickness ranges from 10 to 140 feet. As of January 2023, there were 42 active rigs in the Bakken.[37]

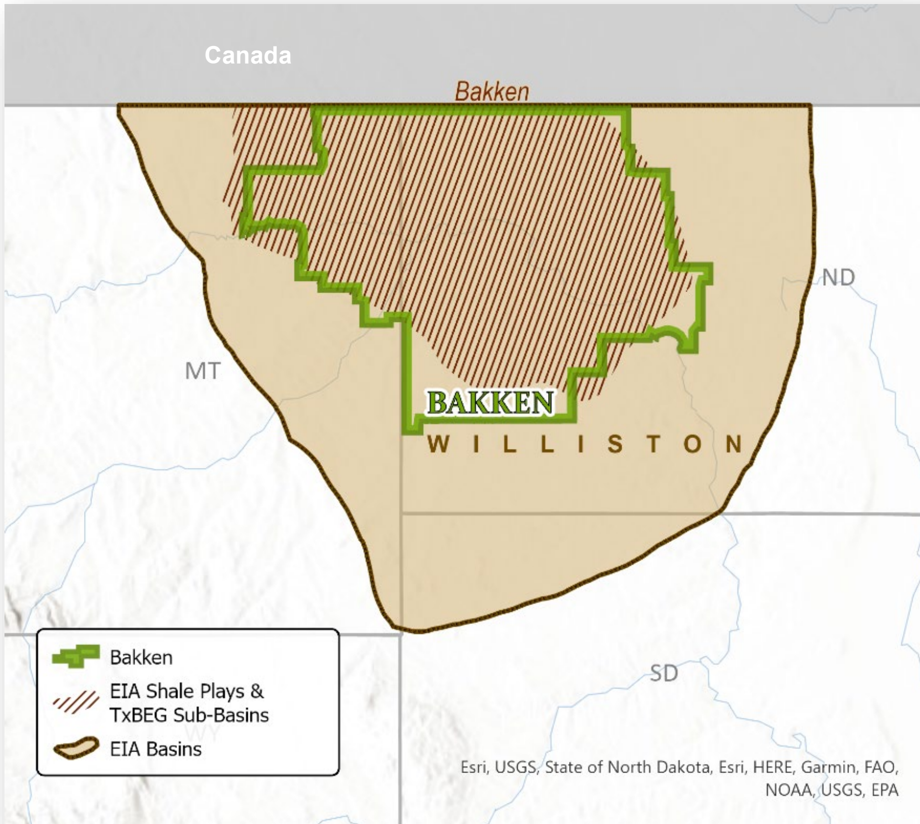

Figure 7: Bakken Development Region

A total of ~17,300 wells have been drilled and completed in this region since 2010, and average horizontal lateral lengths have increased from 7,960 feet to 9,764 feet over this period (~23%).[38] Cumulative oil production has exceeded 4,134,092,000 barrels, while total gas production stands just over 7,576,175,000 mcf.[39] Recoverable quantities of oil and natural gas vary by estimate because the Bakken shale generally has low porosity and low permeability, making the hydrocarbons challenging to extract. Current recoverable estimates range from 4.4 to 11.4 billion bbls of oil, 3.43 to 11.25 trillion cubic feet of gas, and 0.23 to 0.95 billion bbls of natural gas liquids.[40]

[36] Nordeng, Stephan, 2010. A Brief History of Oil Production from the Bakken Formation in the Williston Basin. North Dakota Department of Mineral Resources. Retrieved June 15, 2023.

[37] Baker Hughes Rig County – 01/27/2023, https://bakerhughesrigcount.gcs-web.com/na-rig-count (accessed February 2, 2023).

[38] ALL work product using Enverus data.

[39] ALL work product using Enverus data.

[40] US Department of the Interior, "USGS releases new oil and gas assessment for Bakken and Three Forks", Press Release, 30 Apr. 2013, Department of Interior.

2.3 Eagle Ford Region

The East Texas and Maverick basins are included within the Eagle Ford region, which is exclusively in Texas. (**Figure 8**). The Cretaceous-aged Eagle Ford and Austin Chalk formations dominate in this region, extending over an area of approximately 5,000 square miles, almost 50 miles wide and 400 miles long stretching from the Mexican border to East Texas.

Figure 8: Eagle Ford Development Region

The Eagle Ford shale play was first developed in 2008, with depths to the producing formations ranging from 7,000 to 12,000 feet.[41] Formation thickness varies from 150 to 300 feet and as of January 2023, there were 72 active rigs in the region.[42]

Since 2008, there have been ~32,320 wells completed, and the average length of the horizontal laterals has increased from ~4,375 feet to ~7,560 feet (~73%).[43] Gross natural gas withdrawals in the Eagle Ford region rose by 0.9 Bcf/d or 18 percent in 2022, the first annual increase since 2019. Total cumulative oil production exceeds 4,693,223,000 barrels, while cumulative gas production is nearly 22,831,428,000 mcf.[44] According to the U.S. EIA, crude oil production in the Eagle Ford region has increased recently but is still behind the April 2020 production rate of 1.4 MMBPD. Furthermore, economically recoverable oil resources in the Eagle Ford increased to 8.4 billion barrels since 2020, because crude oil prices rose, incentivizing development in areas of previously marginal geologic promise.[45]

[41] U.S. Energy Information Administration. December 2014. Updates to the EIA Eagle Ford Play Maps. https://www.eia.gov/maps/pdf/eagleford122914.pdf (accessed July 11,2022).
[42] Baker Hughes Rig County – 01/27/2023, https://bakerhughesrigcount.gcs-web.com/na-rig-count (accessed February 2, 2023).
[43] ALL work product using Enverus data.
[44] ALL work product using Enverus data.
[45] EIA, Today in Energy, 2022. Principal contributor Troy Cook, Crude Oil Production in Texas's Eagle Ford Region has Been Increasing Since February 2022. Obtained at https://eia.gov/todayinenergy/detail.php?id=53619 on June 24, 2023.

2.4 Rocky Mountain Region

The Rocky Mountain region is mostly the Denver–Julesburg Basin under portions of Colorado, Nebraska, New Mexico, Utah, and Wyoming, covering an area of approximately 5,000,000 acres. (**Figure 9**).

This Cretaceous-period deposit includes the Niobrara and Codell formations, which range in depth from 3,000 to 14,000 feet, and thicknesses of 285 to 385 feet and 3 to 25 feet, respectively.[46,47]

As of January 2023, 16 active rigs were running in the Rocky Mountain region.[48] Exploration and production of mostly horizontal wells began here in 2010, and ~39,800 wells have been drilled and completed since. The average horizontal lateral length has increased from ~3,800 feet to 9,100 feet over this period (~140%).[49] Total cumulative oil production has exceeded 2,094,673,000 barrels, while cumulative gas production is over 23,296,129,500 mcf.[50]

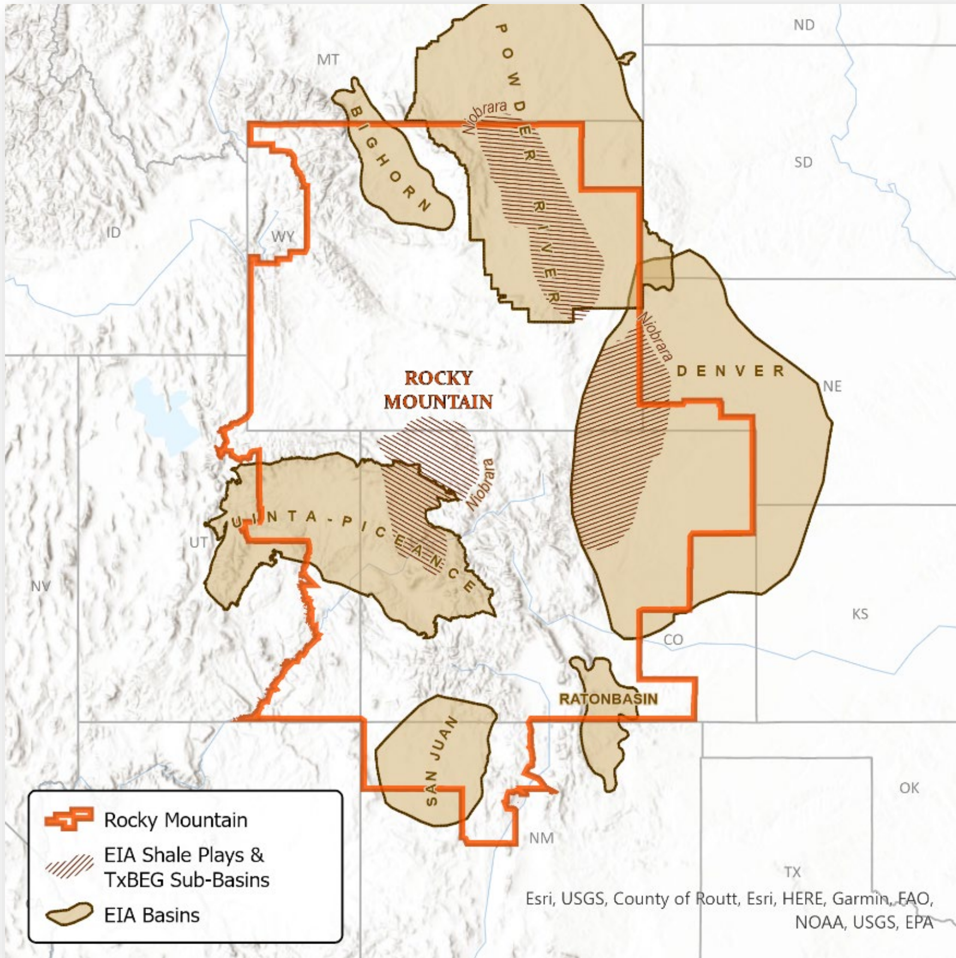

Figure 9: Rocky Mountain Development Region

[46] Shale Experts, 2023. Niobrara Sale Overview, https://www.shaleexperts.com/plays/niobrara-shale/Overview (accessed June 16, 2023).

[47] Higley, D.K., Cox, D.O., 2007. Oil and gas exploration and development along the front range in the Denver Basin of Colorado, Nebraska, and Wyoming, USGS Province 39: U.S. Geological Survey Digital Data Series DDS–69–P.

[48] Baker Hughes Rig County – 01/27/2023, https://bakerhughesrigcount.gcs-web.com/na-rig-count (accessed February 2, 2023).

[49] ALL work product using Enverus data.

[50] ALL work product using Enverus data.

2.5 Mid-Continent Region

The Mid-Continent region encompasses an area of approximately 11,138 square miles and includes portions of the Anadarko, Arkoma, Bend Arch, and Fort Worth basins in Arkansas, Kansas, Oklahoma, and Texas. (**Figure 10**). Primary plays are the Barnett, Fayetteville, Granite Wash, Mississippian Lime, and Woodford-Meramec (Stack/Scoop) of the Devonian-Mississippian geologic period.

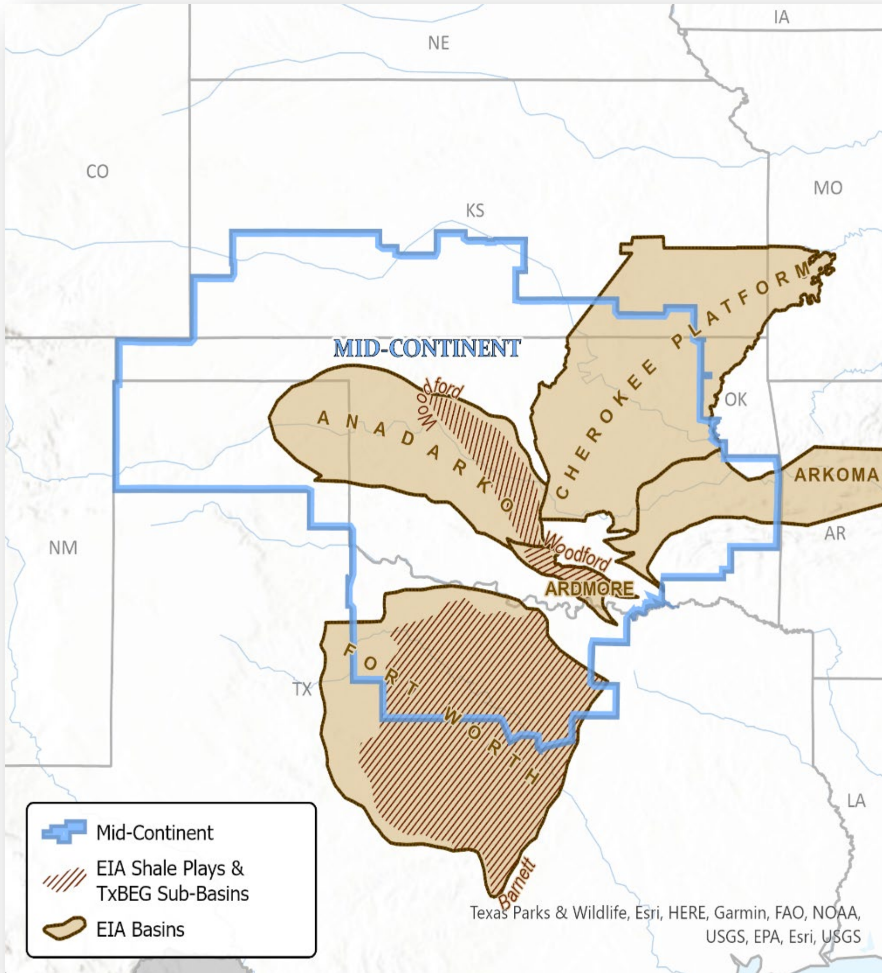

Figure 10: Mid-Continent Development Region

Play depths range from 1,500 to 16,000 feet, with formation thicknesses varying from 50 to 550 feet. Since its discovery in 1991, ~36,600 wells have been drilled and completed in the Mid-Continent Region,[51] average horizontal lateral lengths increasing from ~3,750 feet to ~7,275 feet (~94%) between 2010 and 2022. As of January 2023, there were 48 active rigs operating in this region.[52] Total cumulative oil production exceeds 1,565,917,000 barrels, and cumulative gas production is ~32,635,378,000 mcf.[53]

[51] ALL work product using Enverus data.
[52] Baker Hughes Rig County – 01/27/2023, https://bakerhughesrigcount.gcs-web.com/na-rig-count (accessed February 2, 2023).
[53] ALL work product using Enverus data.

2.6 Appalachian Region

The Appalachian region includes the Marcellus and Utica-Point Pleasant plays of New York, Ohio, Pennsylvania, and West Virginia and covers an area of approximately 157,000 square miles (**Figure 11**).[54,55] First developed in 2005 with modern horizontal drill and hydraulic fracturing techniques, the Marcellus Shale was deposited during the Devonian period and ranges in depth from 5,000 to 9,000 feet. It is predominantly a gas play and varies from 50 to 200 feet thickness.[56]

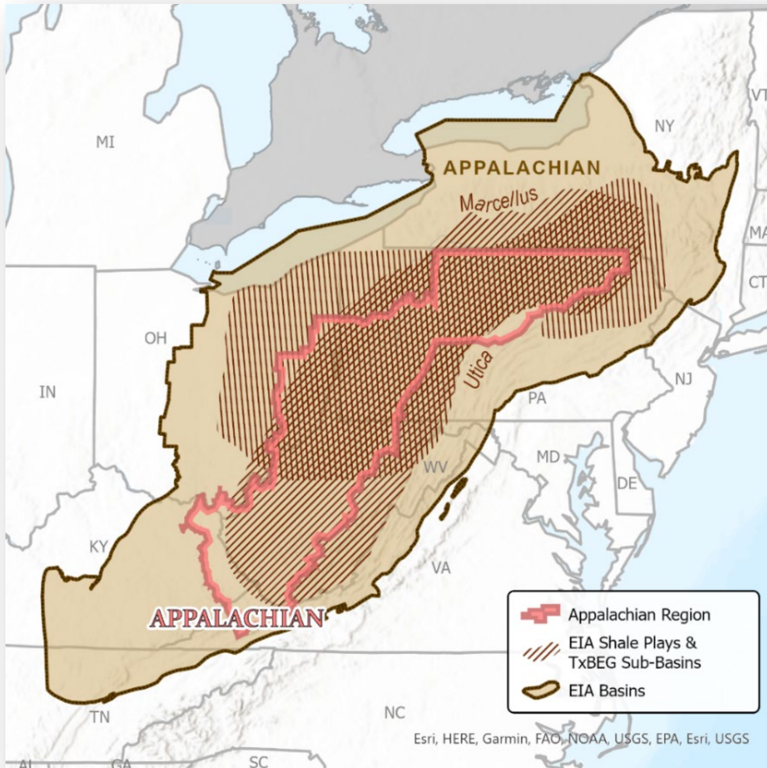

Figure 11: Appalachian Development Region

Significant development and production of natural gas, liquids, and oil began here in 2010 from the Ordovician Utica-Point Pleasant play at depths of 2,000 to 15,500 feet. Formation thickness can be 100 to 500 feet thick. As of January 2023, there were ~52 active rigs running in Ohio, Pennsylvania, and West Virginia[57]. The average horizontal lateral lengths have increased from ~3,970 feet to ~10,630 feet (~168%) between 2010 and 2022.[58] About 21,545 wells have been drilled and completed since 2010.

In 2022, the Appalachian Region produced more natural gas than any other U.S. region, accounting for 29 percent of domestic natural gas withdrawals, or 34.6 Bcf/d. The Appalachian region remains the most prolific U.S. natural gas-producing region, however, its production growth has slowed due to inadequate pipeline takeaway capacity.[59] Cumulative oil production from the Appalachian Region exceeds 326,710,000 barrels, while cumulative gas production is ~90,690,123,000 mcf.[60]

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[54] U.S. Energy Information Administration. April 2017. Utica Shale Play – Geology Review. https://www.eia.gov/maps/pdf/UticaShalePlayReport_April2017.pdf (accessed July 11,2022).

[55] U.S. Energy Information Administration. 2017. Marcellus Shale Play – Geology Review. https://www.eia.gov/maps/pdf/MarcellusPlayUpdate_Jan2017.pdf (accessed July 11,2022).

[56] Pennsylvania Department of Environmental Protection. 2020. Unconventional Shale Development. www.depgreenport.state.pa.us/elibrary/GetDocument?docId=1419062&DocName=MARCELLUS SHALE DEVELOPMENT.PDF 1/17/2021 (accessed July 11, 2022)

[57] Baker Hughes Rig County – 01/27/2023, https://rigcounty.bakerhughes.com/na-rig-count (accessed February 2, 2023).

[58] ALL work product using Enverus data.

[59] U.S. EIA, U.S. Natural Gas Production Grew by 4% in 2022, accessed on July 11, 2023, at https://www.eia.gov/todayinenergy/detail.php?id=56000

[60] ALL work product using Enverus data.

2.7 Haynesville Region

The Haynesville region includes the Upper Jurassic Haynesville and Bossier formations in western Louisiana and eastern Texas and covers an area of approximately 9,000 square miles (**Figure 12**). Depths to the Haynesville and Bossier formations range from 9,000 to 14,000 feet, with formation thickness of 200 to 300 feet. Since significant development began in 2008, ~10,700 wells have been drilled and completed and average horizontal lateral lengths had increased from ~4,300 feet to 7,980 feet (~86%) by 2022.[61] The rig count as of January 2023 was 69.[62]

Figure 12: Haynesville Development Region

The Haynesville-Bossier is the third-largest shale gas-producing play in the U.S., behind the Marcellus and Permian plays. Natural gas production in the Haynesville increased in 2022 from 2.0 Bcf/d to 15.3 Bcf/d, representing 13 percent of U.S. gross natural gas withdrawals. Due to its juxtaposition to the Gulf Coast, the Haynesville region is a strategic location for operators to extract natural gas as liquefied natural gas export terminals and industrial facilities have been growing.[63] Total cumulative oil production for the Haynesville Region is over 64,320,500 barrels, and cumulative gas production is ~33,512,582,500 mcf.[64]

[61] ALL work product using Enverus data.

[62] Baker Hughes Rig County – 01/27/2023, https://bakerhughesrigcount.gcs-web.com/na-rig-count (accessed February 2, 2023).

[63] U.S. EIA, U.S. Natural Gas Production Grew by 4% in 2022, accessed on July 11, 2023, at https://www.eia.gov/todayinenergy/detail.php?id=56000

[64] ALL work product using Enverus data.

3 Advances in Development Techniques

Generally, regional geology and surface operating conditions have meant implementation of modern technology to varying degrees based on variables such as fresh water resources, waste water disposal capacity, and exploration and production capital funding realities. This section focuses on changes most common to the industry since 2009 when the original Primer was published.

3.1 Lateral Lengths and Water Volumes

3.1.1 Lateral Lengths per Well

Since the initial development of the first unconventional play in the Barnett Shale in 1991, significant advancements in drilling and completion operations have unlocked reserves from multiple unconventional plays across the U.S. Two of the most significant changes to these operations have been the drilling of longer horizontal laterals and the increased number of completion stages.

Early horizontal wells were typically drilled with lateral lengths of 1,000 to 2,000 feet. However, advances in drilling technology have made it possible to drill much longer laterals. **Figure 13** shows a graph of the increases in horizontal lateral lengths from 2010 to 2022 across the various Development Regions.[65] In 2020, Olympus Energy LLC drilled the Midas 6M, a Marcellus Shale well, with a completed lateral length of 20,060 feet, setting a new record for the longest horizontal wellbore in the U.S. [66]

Longer horizontal laterals increase contact with the reservoir, resulting in more exposure of the reservoir to the stimulation fluid, which can lead to higher production rates.[67] Longer laterals yield lower costs per unit volume of production, where the marginal cost incurred to extend the lateral length of the wellbore has proven to be an economical and efficient way to develop the unconventional resources in most regions; lower unit cost per volume of production.

In addition to drilling longer horizontal laterals, operators have also increased the number of completion stages in their wells. A completion stage is a section of the wellbore hydraulically fractured to create a pathway for oil or gas to flow to the wellbore for production. Legacy unconventional wells typically had only a few completion stages. Today, wells can have dozens of completion stages. Increasing the number of completion stages increases production rates as more completion stages means more fractures. More completion stages can help to distribute production drainage over a larger area, which can help to extend the life of the well.

Figure 13 shows lateral lengths have increased by approximately 23-168 percent across the development regions since 2010. These increases in lateral length have allowed operators to access greater amounts of resources while decreasing surface use, truck traffic, and air emissions, resulting in reduced environmental impacts per barrel or Mcf produced. Furthermore, the increased lateral lengths have allowed operations to access more resources per well reducing the cost of development and increasing the recoverable reserves.

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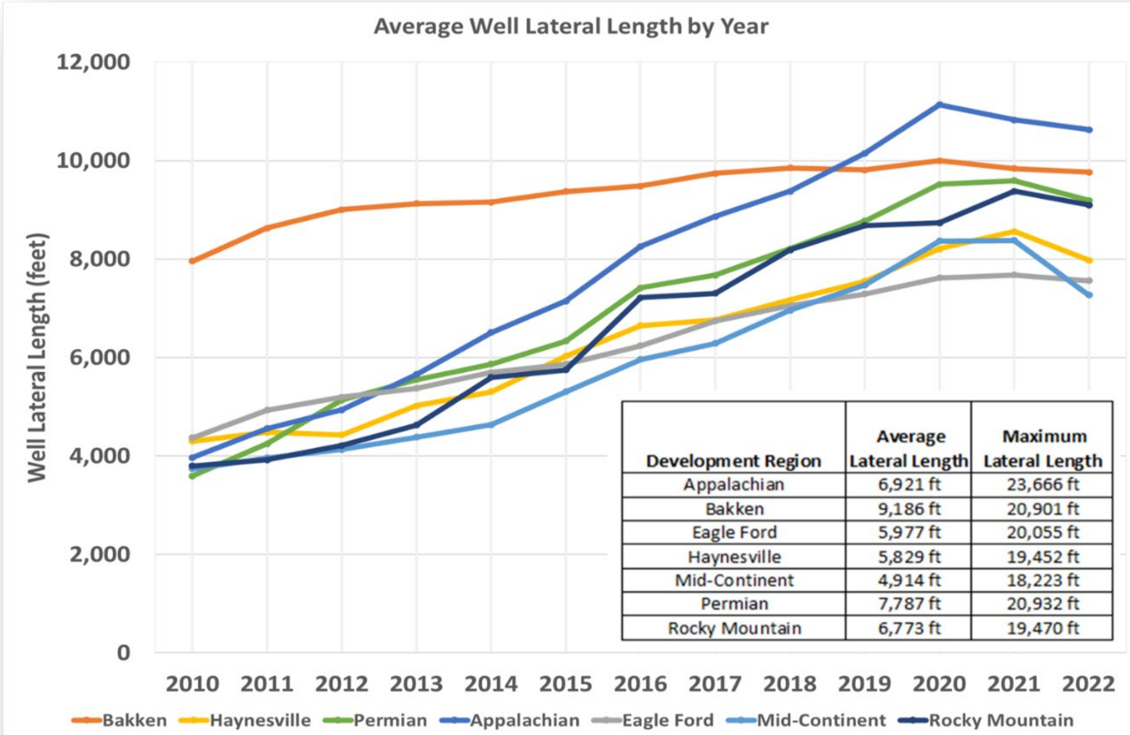
[65] ALL work product using Enverus data.

[66] Pittsburgh Business Times. December 22, 2020. Olympus Energy completes record-breaking natural gas well. https:

[67] Rassenfoss, S., 2022. The Trend in Drilling Horizontal Wells is Longer, Faster, Cheaper, Journal of Petroleum Technology, ISSN: 1944-978X, accessed on July 25, 2023, at https://jpt.spe.org/the-trend-in-drilling-horizontal-wells-is-longer-faster-cheaper



Development Region	Average Lateral Length	Maximum Lateral Length
Appalachian	6,921 ft	23,666 ft
Bakken	9,186 ft	20,901 ft
Eagle Ford	5,977 ft	20,055 ft
Haynesville	5,829 ft	19,452 ft
Mid-Continent	4,914 ft	18,223 ft
Permian	7,787 ft	20,932 ft
Rocky Mountain	6,773 ft	19,470 ft

Figure 13: Average Lateral Length by Year From 2010 to 2022

As an example, through mid-2018, Range Resources LLC had drilled over 1,000 wells in Pennsylvania. The average lateral lengths of horizontal wellbores drilled between 2006 and 2016 for 850 Marcellus wells was 3,950 feet, ranging from 1,500 and 11,000 feet. When Range began focusing on developing core acreage, or reservoir with the best economics, utilizing longer laterals in late 2016, their Marcellus extended-lateral drilling program started to succeed. The outcome of which resulted in lateral lengths increasing to ~9,450 feet for 200 wells drilled in 2017 and the first half of 2018. Laterals now routinely extend beyond 12,000 feet.[68] **Figure 14** shows Range Resources increases in drilling lengths from 2007 to 2018.[69]

The rate at which horizontal wellbore length has increased has somewhat supplemented the decline in the number of wells completed annually by exposing more of the reservoir per well. For example, in the Permian Development Region 8,332 wells were completed in 2012 at an average lateral length of 5,137 feet, resulting in ~42.8 million feet of horizontal wellbore. When compared with the ~3,300 less wells completed (5,034) in 2022 but at an average lateral length of ~80 percent greater (9,193 feet), an

[68] Technologies Reduce Drilling Flat Time. https://www.gyrodata.com/wp-content/uploads/2019/06/Technologies-Reduce-Drilling-Flat-Time.pdf

[69] Doak, J., Kravits, M., Spartz, M., and Quinn, P., January 2019. The American Oil & Gas Reporter - Best Practices Extend Lateral Lengths, Figure 1, accessed on February 17, 2023, at https://www.aogr.com/magazine/editors-choice/best-practices-extend-lateral-lengths

additional ~3.476 million feet of horizontal wellbore was drilled (46.28 million feet). This trend for the Permian is impressive, however this is not the case in the remaining six development regions.

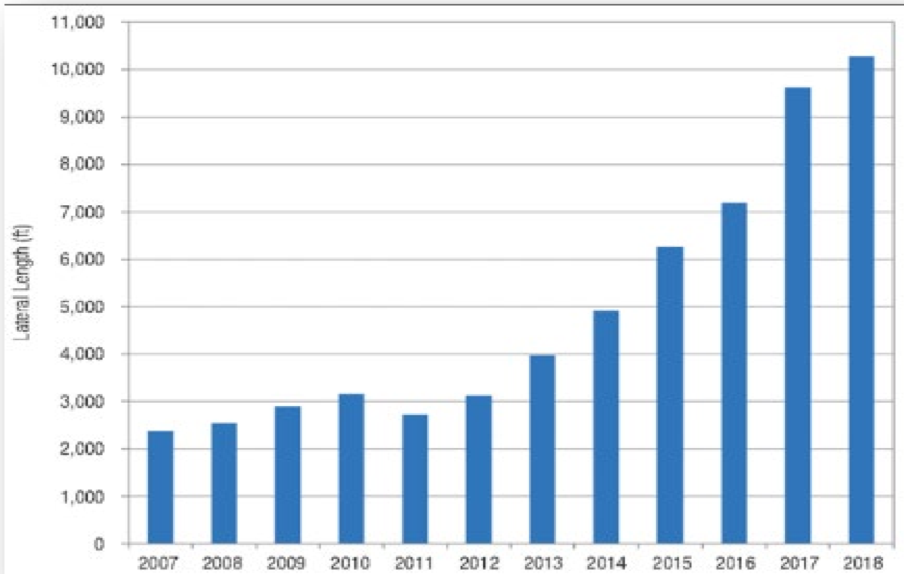


Figure 14: Range Resources Lateral Length from 2007-2018

When average annual lateral lengths are conflated with the greatest number of wells drilled for a specific year per region, a total annual horizontal wellbore distance is generated, the resulting lengths are greater than what was drilled in 2022. However, two of the regions, Rocky Mountain and Appalachian, did have total annual horizontal wellbore distances that exceeded their maximum wells drilled year distances, both in 2018 versus 2011 and 2014, respectively. The remaining four regions have not seen their total annual horizontal wellbore distance exceed what was drilled in the year with their greatest number of new wells drilled. **Figure 15** depicts the cumulative

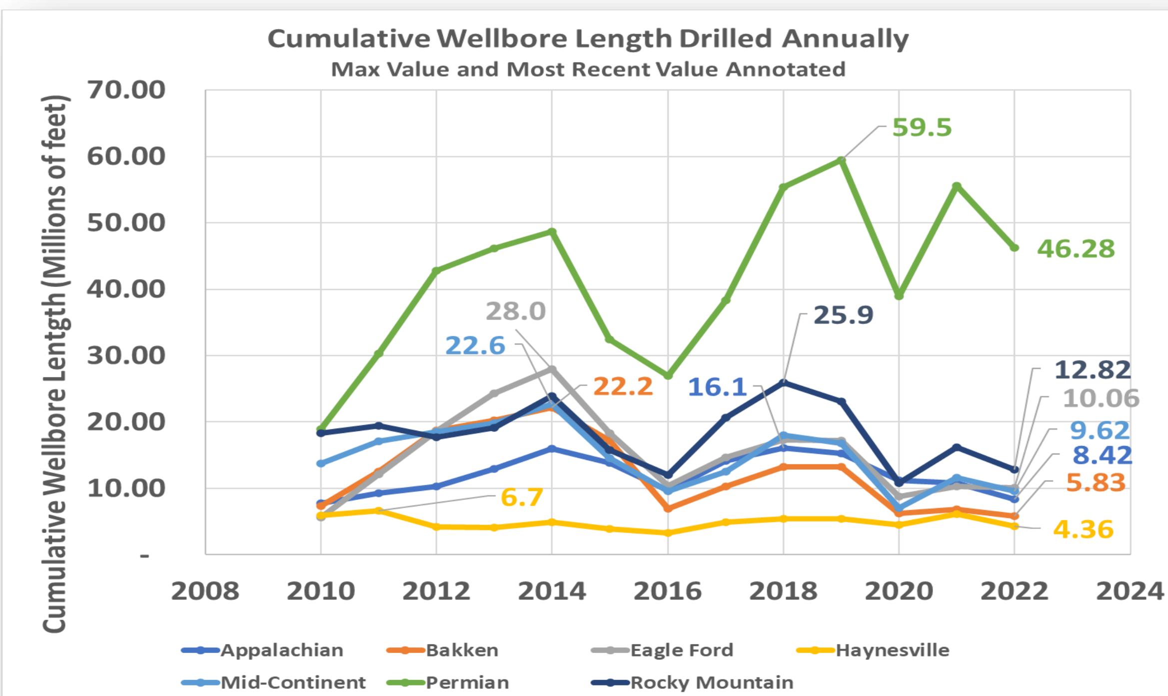


Figure 15: Cumulative Wellbore Length Drilled Annually

wellbore length drilled annually per development region, the value for the year with the maximum wells drilled and most recent values are annotated.

3.1.2 Water Volumes per Well

Hydraulic fracturing is the primary completion technique for shale reservoir stimulation; therefore, drilling longer laterals has resulted in greater volumes of water needed to fracture boreholes. For example, in 2010 the average length of a horizontal well in the Eagle Ford was roughly 4,000 feet. The amount of water required to fracture a well of this length was less than 120,000 barrels (bbls). However, by 2022 the average length of a horizontal wellbore in the Eagle Ford Shale had increased to 8,000 feet, increasing the number of fracture stages per wellbore and requiring an average of nearly 355,000 bbls of water per well.

It should be noted that in 2010, water used for fracturing was primarily fresh water, while in 2022, the primary source of water for fracturing was recycled or reused PW. This change in source water can account for considerable conservation of fresh water resources and is a contributing factor to the development of a new midstream market for treating and managing PW.

According to the GWPC Produced Water Report 2023 – Regulations and Practices Update report, the use of fresh water is down across all regions[70] and the Permian region ranked number one for annual recycled produced water volumes, with approximately 1.17 billion barrels. Relatedly, the GWPC Water Volumes Report for 2021 showed a reduction in injection volume for the Permian Basin from 2017 and 2021 of 1,787,439,000 bbls, a possible corollary for the increased prevalence of reused and recycled produced water[71]

Figure 16 shows the increase in hydraulic fracture treatment water volumes from 2010 to 2022[72]. The average water volume per completion is based on water volumes included in the Enverus dataset. Water volumes were not available for every well in the dataset. As shown in the graph, fracture water volumes have increased in the regions from around 120,000 bbls in 2010 to nearly 600,000 bbls of water by 2022. The water volume increases are not a direct ratio to lateral length. Rather, each completion is designed based on formation characteristics, fluid and proppant selection, and perforation clusters. Frac design variables affecting water volume include:[73]

- Formation porosity and permeability
- Lateral length
- Brittleness vs. ductility (Young's Modulus, Poisson's Ratio, Fracture Toughness)
- Thickness
- Barriers
- Depth
- In-situ stress
- Maximum principle stress direction
    - Lithology of Pay
    - Stress Anisotropy
    - Natural Fractures
    - Gas or Liquids Reservoir
    - Temperature
    - Reservoir Pressure

[70] GWPC Produced Water Report 2023 - Regulations and Practices Update, May 2023

[71] Texas Produced Water Consortium 2022. Beneficial Use of Produced Water in Texas: Challenges, Opportunities and the Path Forward"

[72] ALL Work Product based on Enverus Dataset, January 2023.

[73] Beard, T. 2011. Fracture Design in Horizontal Shale Wells – Data Gathering to Implementation, EPA Hydraulic Fracturing Workshop, Chesapeake Energy Corporation

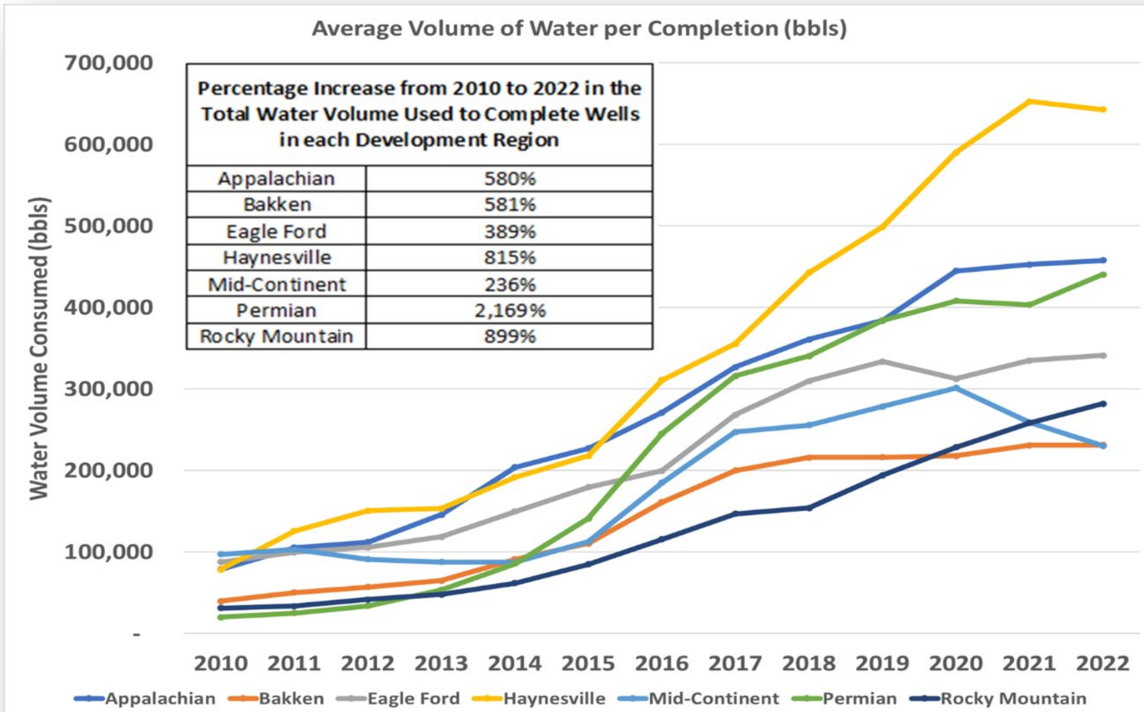


Figure 16: Changes in Water Volumes Per Completion From 2010 to 2022

The ratio of water volume to increased lateral length varies by region. For example, Haynesville lateral lengths doubled over this 12 year period, and water volume increased 4.5 times, whereas the Appalachian laterals almost tripled in length, but water volume only increased three-fold.

3.2 Multi-Well Pads and Drilling Efficiencies

Rooted in operating efficiencies and economies of scale, multi-well pad development has become the norm in nearly all major onshore U.S. basins. Advantages include batch drilling and simultaneous completions[74], as well as savings on shared pad infrastructure, meaning fewer access roads, compressors, pipelines, etc. Disadvantages are larger pad sizes on a single surface owner, more directional work, production delays from spud to turn-in-line, and more planning.[75] That extra planning includes well spacing optimization, anti-collision safeguards, and careful fracture stimulation design to preclude interference with existing production.[76] While average wells per pad vary by basin and

[74] Abramov, A., September 2020. Journal of Petroleum Exploration and Production Technology, Agile methodology of well pad development. https://link.springer.com/article/10.1007/s13202-020-00993-3

[75] DrillingPoint, December 2014. Cost Reduction: Understanding The Economics of Multi-Well Pad Drilling. https://www.drillingpoint.com/p2847/cost-reduction-understanding-the-economics-of-multi-well-pad-drilling/

[76] Popova, O., and Long, G., American Journal of Transportation, 2021. Drilling and completion improvements support Permian Basin hydrocarbon production, https://ajot.com/news/drilling-and-completion-improvements-support-permian-basin-hydrocarbon-production

operator, from as few as two in the Haynesville[77] to an average of six in the Marcellus,[78] some operators doing high-density development are drilling as many as 24 to 40 wells on super pads.[79]

EQT Corporation, for example, has realized efficiencies in drilling speed and operations in the Appalachian Basin, resulting in benefits associated with reductions in the amount of surface disturbance and operations emissions. Drilling only one well per location adds 50 to 70 truck trips over area roadways each week, meaning increasing the number of wells per pad decreases truck traffic and associated exhaust emissions.[80]

Studies have shown that six to eight horizontal wells drilled from one location can access the same reservoir volume as 16 vertical wells at separate locations.[81] As applied in the Utica/Marcellus development region, this approach has reduced surface impacts by an estimated 50 percent.[82]

The way rig contracts are typically structured, the less non-productive time (NPT) the better for operators in major onshore shale basins. Getting to total depth (TD) as quickly as possible while maintaining wellbore integrity means lower overall cost and an earlier turn-in-line date.[83] Once again, technology is allowing these efficiency gains.[84] Operators have generally focused on technology advancements in rig construction, directional tools, optimized drilling fluids, casing design, and other industry best practices.[85] Though traditionally a heavily mechanized process, operators looking for cost savings will undoubtedly begin using automation and digital process controls to reduce cycle times and improve cash flow.[86]

As shown in **Figure 17** below, according to a 2019 Best Practices article published in the American Oil and Gas Reporter, Range Resources was able to reduce their drilling costs per lateral foot from upwards of $1,600 in 2012 to less than $200 in 2018.[87]

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[77] McLean, C. BTU Analytics, 2019. Smaller Pad Sizes Driving Lower Haynesville Rig Efficiency. https://btuanalytics.com/shale-production/smaller-pad-sizes-driving-lower-haynesville-rig-efficiency/

[78] Pickett, Al. The American Oil & Gas Reporter, 2018. Efficiency Gains Help Independents Find Success In Marcellus, Utica Shales. https://www.aogr.com/magazine/editors-choice/efficiency-gains-help-independents-find-success-in-marcellus-utica-shales

[79] Gupta, U. and Turaga, U. 2020. Enter monster well-pads. https://adi-analytics.com/2019/11/12/enter-mega-pads-in-shale-drilling/

[80] Pickett, Al. The American Oil & Gas Reporter, 2023. Pad Drilling - Leading Operators Improve Efficiency and Effectiveness of Multiwell Pad Operations (aogr.com)

[81] API, 2018. Response to Key Technical Issues Requested by the Delaware River Basin Commission on its Proposed New 18 CFR Part 440 Review.

[82] ibid

[83] The American Oil & Gas Reporter, June 2019. Technologies Reduce Drilling Flat Time. https://www.gyrodata.com/wp-content/uploads/2019/06/Technologies-Reduce-Drilling-Flat-Time.pdf

[84] ibid

[85] Best Practices Extend Lateral Lengths. https://www.aogr.com/magazine/editors-choice/best-practices-extend-lateral-lengths

[86] An Outlook of Drilling Technologies and Innovations: Present Status and Future Trends. https://www.mdpi.com/1996-1073/14/15/4499/pdf

[87] Doak, J., Kravits, M., Spartz, M., and Quinn, P., January 2019. The American Oil & Gas Reporter - Best Practices Extend Lateral Lengths, Figure 1, accessed on February 17, 2023, at https://www.aogr.com/magazine/editors-choice/best-practices-extend-lateral-lengths

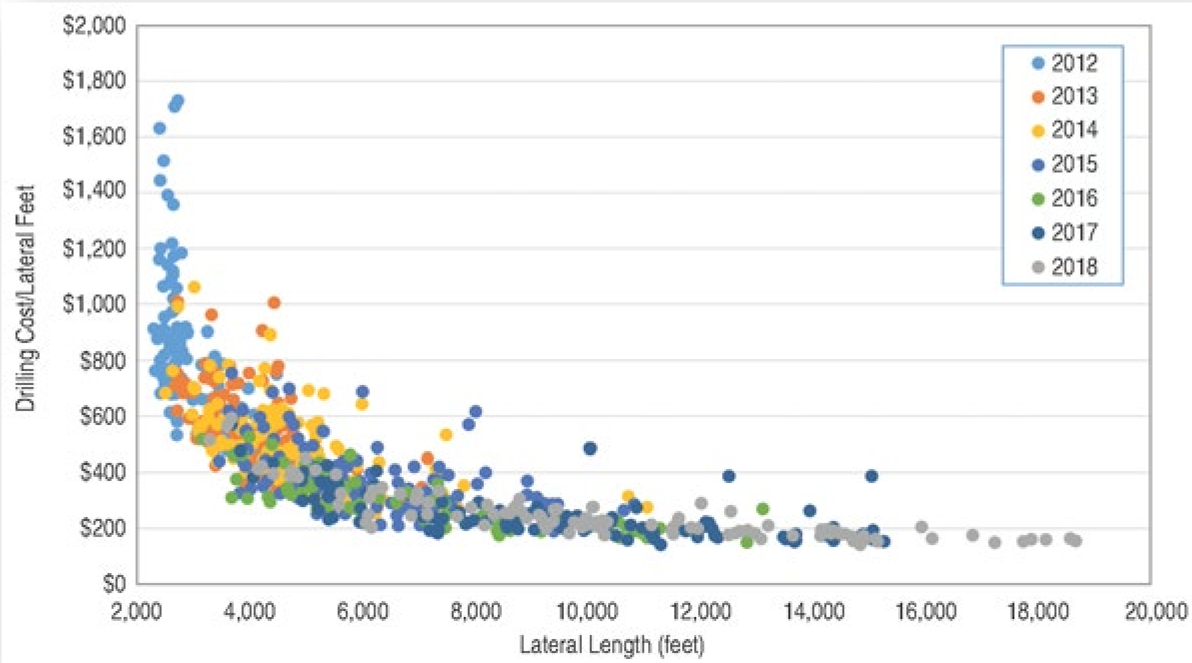

Figure 17: Range Resources Drilling Cost Per Lateral Foot (2012 – 2018)

3.3 Zipper and Simul-Frac Completion Technologies

Operators are always looking for new ways to gain efficiency at the surface. Zipper fracturing is a method employed on a single pad with multiple wells whereby one horizontal well is being completed while another is being prepped for fracturing. It earns its name from the zipper-like configuration of the fracture stages conducted on adjacent wells with parallel horizontal wellbores drilled with relatively tight spacing.[88] This well completion of zipper fracturing involves hydraulically fracturing a stage in one well, while wireline and perforating operations take place simultaneously in another well on the same pad.[89]

Approximately 12 percent of the horizontal wells in the U.S. were completed in 2011 with the zipper fracturing method that allows for rapid transition between stages in offsetting wells. By the fourth quarter of 2021, zipper fracturing represented 78 percent of U.S. completions because of cost savings and operational flexibility.[90]

[88] Jacobs, Trent. 2014. The Shale Evolution: Zipper Fracture Takes Hold. Journal of Petroleum Technology. https://jpt.spe.org/shale-evolution-zipper-fracture-takes-hold (Accessed June 27, 2023).

[89] ibid

[90] Jacobs, T. 2021. Simul-Frac Gains Momentum in US Shale, Cuts Completion Times in Half, Journal of Petroleum Technology, https://jpt.spe.org/simul-frac-gains-momentum-in-us-shale-doubles-completion-speeds (Accessed June 27, 2023).

As seen in **Figure 18**, as of 2014, various types of well completion methods were being utilized in unconventional horizontal well development.[91,92] The modified zipper fracturing (MZF) method was the latest evolution beyond regular zipper fracturing or the Texas Two Step alternating fracturing method, where fracture stages are stimulated out of sequence.[93]

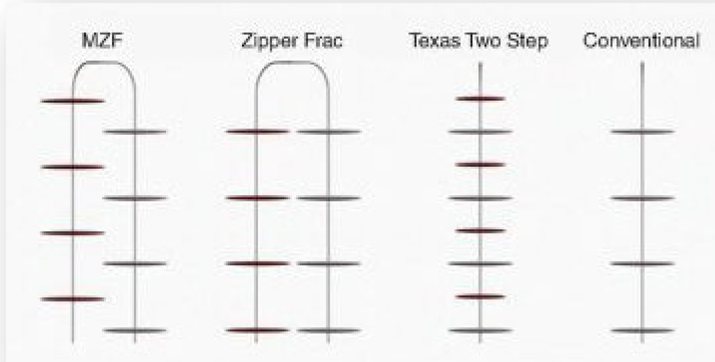

Figure 18: Zipper Frac Approaches

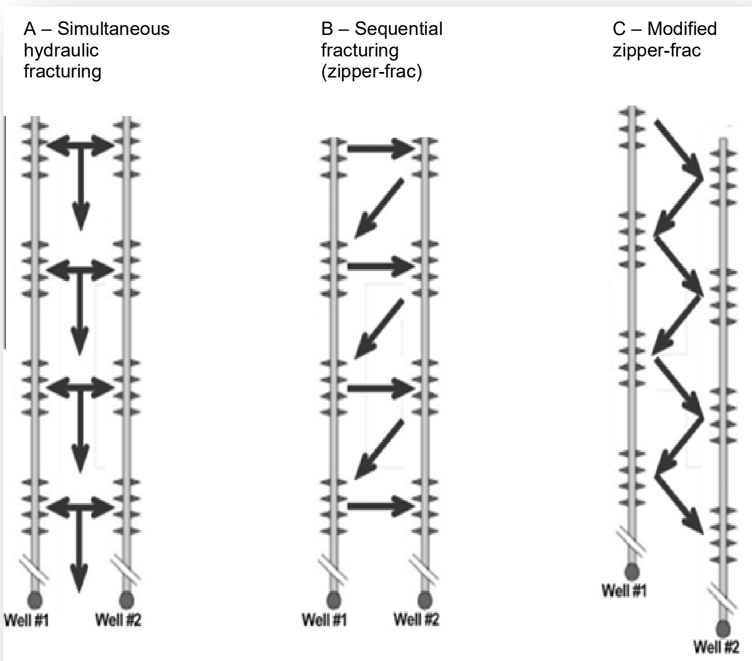

Figure 19: Comparison Shale Completion Schemes

From the literature, it has been stated that simul-frac operations can achieve over double the lateral footage stimulation compared to zipper-frac operations.[94] Simul-frac operations help stimulate more frac stages across multiple wells at the same time using a single frac convoy.[95] When zipper fracturing a four-well pad, two wells are stimulated while the other two wells remain idle. With simul-frac operations, idle time is eliminated by completing four wells at once by pumping down two wells at the same time while perforating the other two wells on the same pad.[96] **Figure 19** compares zipper and modified zipper-fracs with simultaneous hydraulic fracturing in a visual depiction of the stimulation movement on the pad.

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[91] Jacobs, T. 2014. The Shale Evolution: Zipper Fracture Takes Hold. Journal of Petroleum Technology. https://jpt.spe.org/shale-evolution-zipper-fracture-takes-hold (Accessed June 27, 2023).

[92] Image courtesy of Mohamed Soliman/Texas Tech University.

[93] Jacobs, T. 2014. The Shale Evolution: Zipper Fracture Takes Hold. Journal of Petroleum Technology. https://jpt.spe.org/shale-evolution-zipper-fracture-takes-hold (Accessed June 27, 2023).

[94] Halliburton. 2020. Reducing Days on Location and Time to First Oil Simultaneous Fracturing Operations. https://cdn.brandfolder.io/PKKYOY46/at/qeyail-fu85w0-640d3b/2020-MKTG-PES-11950_SimulFrac_Brochure.pdf (Accessed June 27, 2023).

[95] ibid

[96] ibid

Figure 20 shows an example of a simul-frac operation.[97] Contractors and reputable journals have published multiple articles and papers providing both the pros and cons of the simul-frac completion approach. In 2023 articles, Halliburton and ProFrac have stated that simul-frac operations not only allows for more efficiency and making forward progress across all four wells on the same pad, but it also provides:[98,99]

- Average pumping rates of 160 barrels per minute;
- Stimulating up to 3,600 feet per day;
- Pumping 450+ hours per month;
- Completing 50 percent more stages per month;
- Reducing days on location by 50 percent; and
- Reducing fuel consumption and emissions.

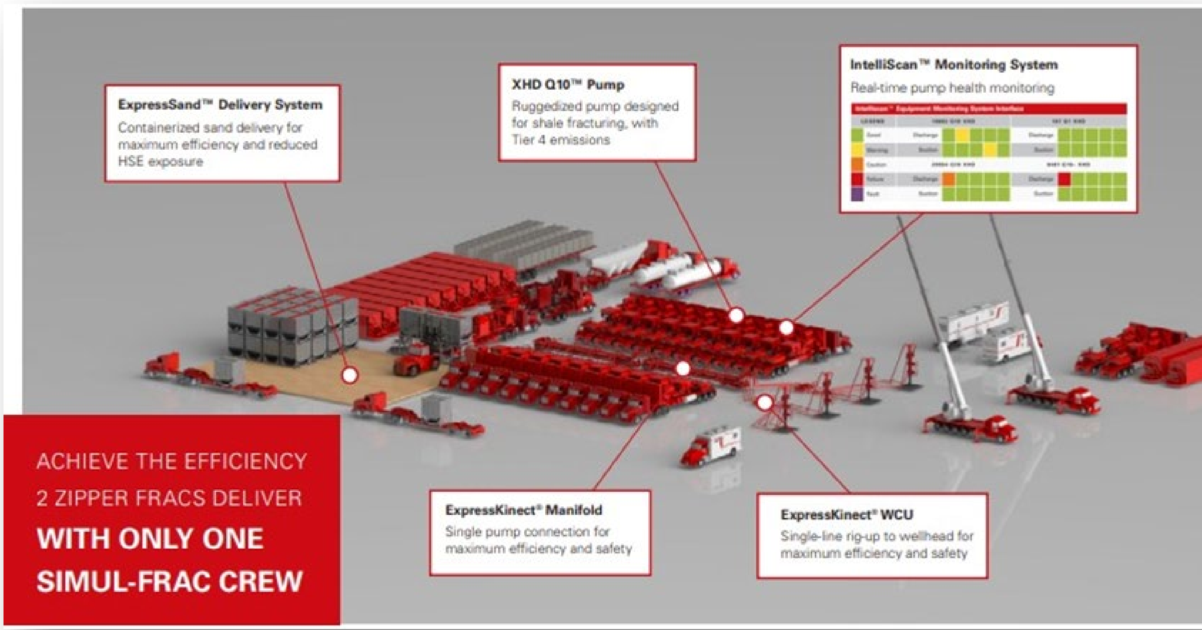

Figure 20: Example of a Simul-Frac Operation

Additionally, a 2021 SPE Journal of Petroleum Technology article presents several potential benefits, indicating simul-frac operations reduce completion times in some instances by more than half, as compared to zipper fracs.[100] A typical simul-frac requires at least 25 percent more horsepower than the average zipper frac spread.[101] However, zipper fracturing remains the dominant completion technique for U.S. producers and has seen efficiency gains of 43 percent since 2017. Despite this, research shows

[97] Halliburton. 2023. Simul-Frac Operations Double Efficiency Gains. https://www.halliburton.com/en/completions/stimulation/hydraulic-fracturing/simultaneous-fracturing (Accessed June 27, 2023).
[98] ibid
[99] ProFrac. 2023. Simul-frac Significantly Improve Frac Efficiency. https://profrac.com/services/simul-frac/ (Accessed June 27, 2023).
[100] Jacobs, T. 2021. Simul-Frac Gains Momentum in US Shale, Cuts Completion Times in Half, Journal of Petroleum Technology, https://jpt.spe.org/simul-frac-gains-momentum-in-us-shale-doubles-completion-speeds (Accessed June 27, 2023).
[101] ibid

that in 2020 simul-frac jobs completed their stages 60 percent faster.[102] Additionally, **Figure 21** details results from a case study comparing traditional pad development (Pad X) to simul-frac operations. Many metrics improved with this method, including more average stages per day and average lateral length per day fractured.[103]

Further research from Ovintiv indicates that the simul-frac completion approach has lowered their average well cost by $400,000.[104] Simul-fracs operations require more upfront capital due to the increased frac fleet size, water resources, and sand volumes required at one time.[105]

Frac Style Comparison			
	Pad X (trad)	Pad 2 (Simul)	%
# of Wells	2	4	-
# of Stages	62	192	-
Days Pumping	9	15	67%
Avg Stages / Day	7.44	14.2	91%
Avg Lat - Ft/ Day	2,160	3,162	46%
Average Rate (bpm)	113.2	154.4	-
Average Stg Time (hrs)	2.04	2.60	-

Figure 21: ProFrac Case Study in the Midland Basin Showing Simul-Frac Efficiency

During simul-frac operations, the pumping rate is split between the wells, which means each well on the pad may be stimulated at a lower rate, which might be the reason operators have not extensively used the technique in over-pressured and screen out-prone formations such as Haynesville Shale.[106]

The epicenter of simul-frac operations is the Permian basin, which accounts for almost two-thirds of all simul-fracs completed in the U.S. in 2021. The Permian is the most active basin in the country and has the most pads with four-wells, which some experts believe is the ideal number for an operation designed to function in pairs, such as simul-frac.[107]

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[102] ibid

[103] Source: ProFrac June 2021, ProFrac Significantly Improves Frac Efficiency in Midland Basin

[104] Jacobs, T. 2021. Simul-Frac Gains Momentum in US Shale, Cuts Completion Times in Half, Journal of Petroleum Technology, https://jpt.spe.org/simul-frac-gains-momentum-in-us-shale-doubles-completion-speeds (Accessed June 27, 2023).

[105] ibid

[106] ibid

[107] ibid

3.3.1 Cube Development

A relatively new technique in the oil and gas industry, cube development, repurposes an existing technology called directional drilling. Cube development involves drilling multiple horizontal wells, sometime more than 20, from a single well pad, and according to existing literature should allow for more efficient extraction of oil and gas from the reservoir (**Figure 22**)[108]. As the name suggests, cube development exploits hydrocarbon resources using a three-dimensional, multi-layered approach, producing from multiple horizontal wells in stacked intervals, drilled from a single surface location. Cube development essentially takes advantage of economies of scale. Instead of relying upon multiple drilling rigs on separate pad locations, each working with their own equipment, crew, and logistical support, cube development concentrates all complex operations on to one well pad.

In 2017, Ovintiv (formerly Encana) was among the first operators to test cube development by drilling 45 wells from their RAB Davidson Pad utilizing 300 to 400 foot inter-well spacing. Peak oil production from the RAB Davidson Pad reached nearly 17,000 barrels per day (BPD) in early 2017 (**Figure 23**)[109]. By 2019, Encana (Ovintiv) had drilled more than two dozen multi-well cube development pads in the Permian Basin.

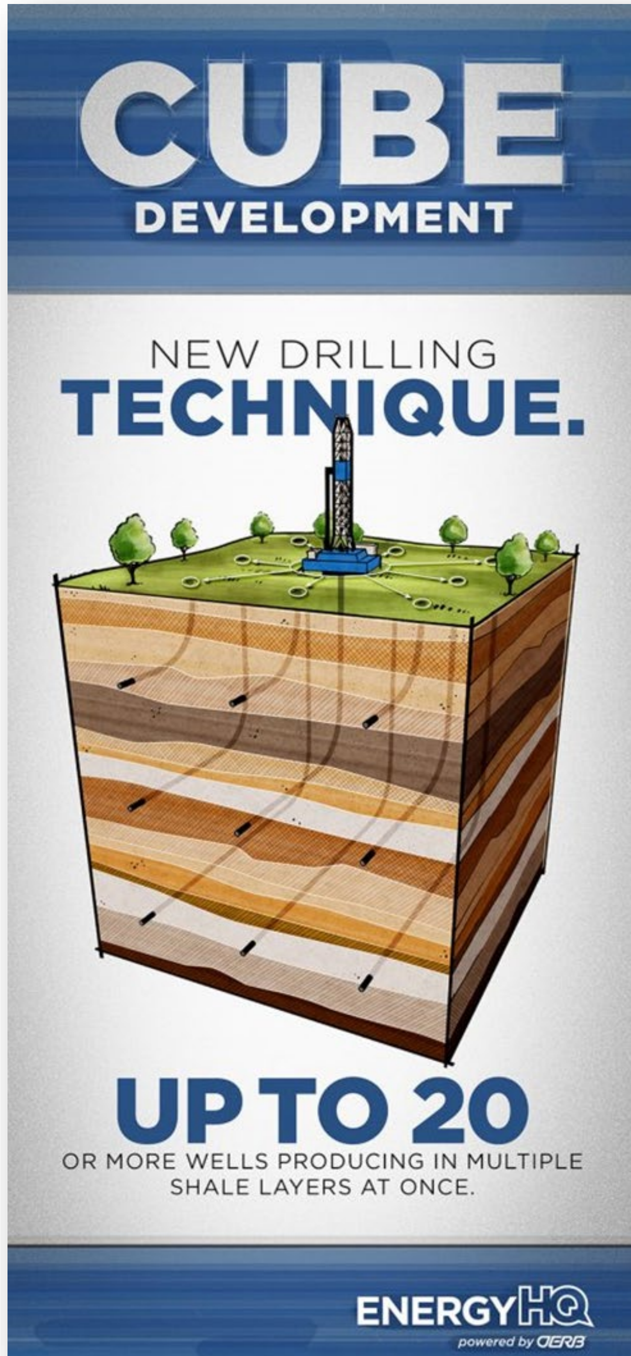

Figure 22: Example of Cube Development

[108] Source: Energy HQ 2019. IS CUBE DEVELOPMENT THE FUTURE OF SHALE PRODUCTION? https://energyhq.com/2018/08/is-cube-development-the-future-of-shale-production/

[109] Source: Oil & Gas 360, June 2-17. How Encana Attacks the Permian: “Developing the Cube” https://www.oilandgas360.com/encana-attacks-permian-developing-cube/

Figure 23: Encana's (Ovintiv) RAB Davidson Cube Development Pad

Concho Resources (Concho) drilled their Dominator Pad in the northern Delaware Basin, a decision likely supported by early reports of successful multi-well pads in the Delaware, Permian, and Midland basins. The Dominator pad consisted of 23 horizontal wells targeting five different landing zones of the Wolfcamp Formation, all drilled within a single section (**Figure 24**)[110,111] The wells on the Dominator Pad were spaced at an average of 230 feet.[112] While initial production yielded promising results, oil production declined quickly, falling as much as 45 percent from original projections.[113,114]

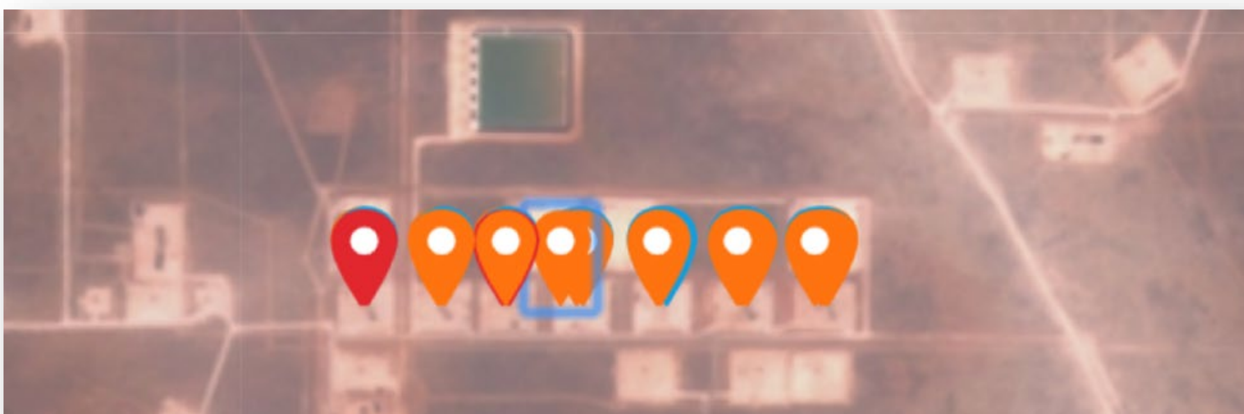

Figure 24: Concho Resources "Dominator Pad" in the Delaware Basin

[110] Source: Westwood Global Energy Group 2019

[111] Jacobs, Trent. 2019. "Dominator Project" Raises Key Questions About Future of Cube Drilling. Journal of Petroleum Technology. https://jpt.spe.org/dominator-project-raises-key-questions-about-future-cube-drilling (Accessed June 29, 2023).

[112] Jacobs, Trent. 2019. "Dominator Project" Raises Key Questions About Future of Cube Drilling. Journal of Petroleum Technology. https://jpt.spe.org/dominator-project-raises-key-questions-about-future-cube-drilling (Accessed June 29, 2023).

[113] ibid

[114] Hart Energy. 2019. Will Cube Development Square with Producers? https://www.hartenergy.com/exclusives/will-cube-development-square-producers-182916 (Accessed June 29, 2023).

Similarly, in Martin County, Texas, QEP Resources took cube development to new extremes, with more than 100 wells in the same section. QEP has dubbed this approach as tank-style pad development (**Figure 25**). [115]

Operators continue to evaluate the viability of the Cube approach, progressing from single well pads to multiple pads constructed in what some industry professionals call a "pad complex."[116] While the concept has not been widely adopted by the industry at the moment, as the data and lessons learned from operators that have committed to this approach increases, that may change.

Figure 25: QEP Resources Tank-Style Pad Development

With the ongoing evaluation Encana (Ovintiv), based on information presented in their Q1 Conference Call, has increased their well spacing to 500 feet (on their Cube pads), which analysis indicates has reduced the interaction between existing and newly drilled wells, also known as parent/child well interaction. [117, 118]

Operators will continue to test spacing density to find optimal spacing for individual plays. However, lower density spacing appears to be the best approach as the industry average for well spacing has increased. In fact, some of the largest onshore operators such as ExxonMobil, Occidental Petroleum, Devon Energy, Chevron, and Pioneer Resources have each focused on optimal well spacing for efficient cube development.

Over the last half-decade, oil and gas operators researched and discovered many new methods to improve productivity. Currently in the Permian Basin, operators using modern drilling methods can develop eight specific horizons from a single well pad. These wells are optimally spaced, vertically and horizontally, to improve recovery of the oil in place, maximize rates of return, and generate the maximum value. Multiple well designs in the Permian have evolved and are much more productive than

[115] Westwood Global Energy Group. 2019. Evolution of Permian pad drilling: Cube development and the pad complex in drilling factories. https://www.westwoodenergy.com/blog/evolution-of-permian-pad-drilling-cube-development-and-the-pad-complex-in-drilling-factories (Accessed June 28, 2023).

[116] ibid

[117] ibid

[118] Ovintiv. 2023. First Quarter 2023 Results Conference Call Presentation. https://investor.ovintiv.com/presentations-events (Accessed June 29, 2023).

initial attempts. Alongside the advancements in drilling technology, completion design has evolved rapidly, resulting in more effective fracture networks and improved proppant placement, allowing wells to be successfully stimulated at approximately 500’ spacing. Such technological advancements improving capital efficiency can generate better overall results. [119]

Cube development and multi-well pads have the potential to increase oil and gas production and reduce costs, but these methods require high initial capital expenditures. Although the oil and gas industry is known to be capital-intensive, the costs of cube development could dwarf previous drilling techniques. At a cube development pad, every well must be drilled and completed before production begins and revenue is generated. The long delay between initial capital expenditure and revenue generation can be too much for some producers. However, economies of scale will help make cube development and multi-well pads more feasible in the future. For example, research shows multi-well pads are more common than single well pads in both the Permian and Delaware basins, as illustrated in **Figure 26.** [120]

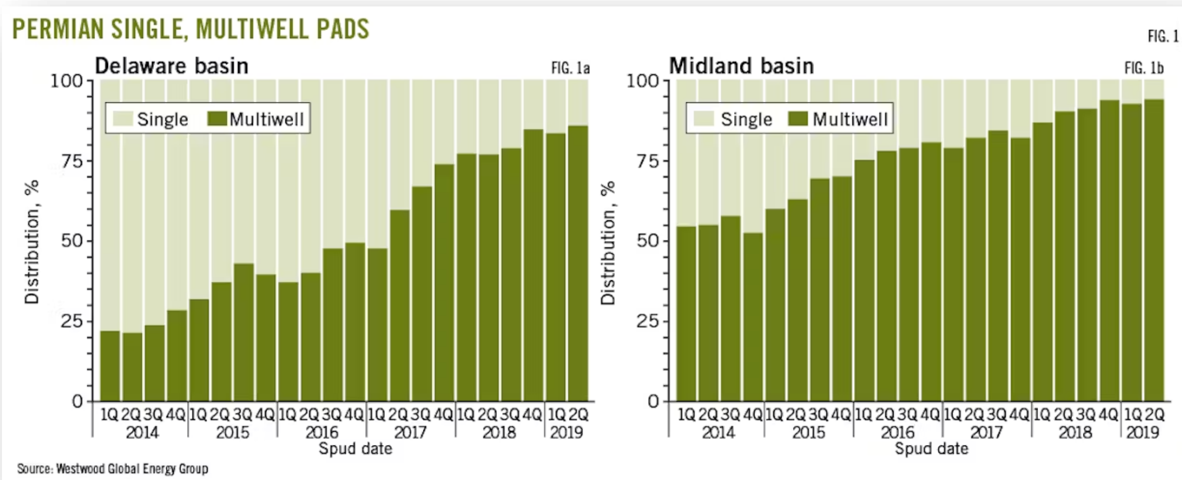

Figure 26: Permian Single versus Multiwell Pad Development 2014 - 2019

[119] Encana, July 2019. Encana in the Permian, Cube Development Facts.

[120] Paula Dittrick, Oil and Gas Journal, October 7, 2019, Permian basin operators improve cube development well planning accessed on June 16, 2023 at https://www.ogj.com/drilling-production/article/14068299/permian-basin-operators-improve-cube-development-well-planning

3.3.2 Multi-Layered or Stacked Formations

Stacked formations are a target for oil and gas operators intending to develop multiple formations from a single wellbore. Wells accessing stacked formations are in production in several unconventional plays in the U.S., including the Midland, Permian, Delaware, and Anadarko basins. In the Midland Basin, many drilling operations are focused on stacked plays, primarily targeting the stacked formations of the Spraberry, Wolfcamp, and Cline. Operators there are targeting up to four reservoirs in a single section using a wine rack pattern, which some industry experts believe could be the future of pad drilling in stacked, unconventional plays (See **Figure 27**).[121]

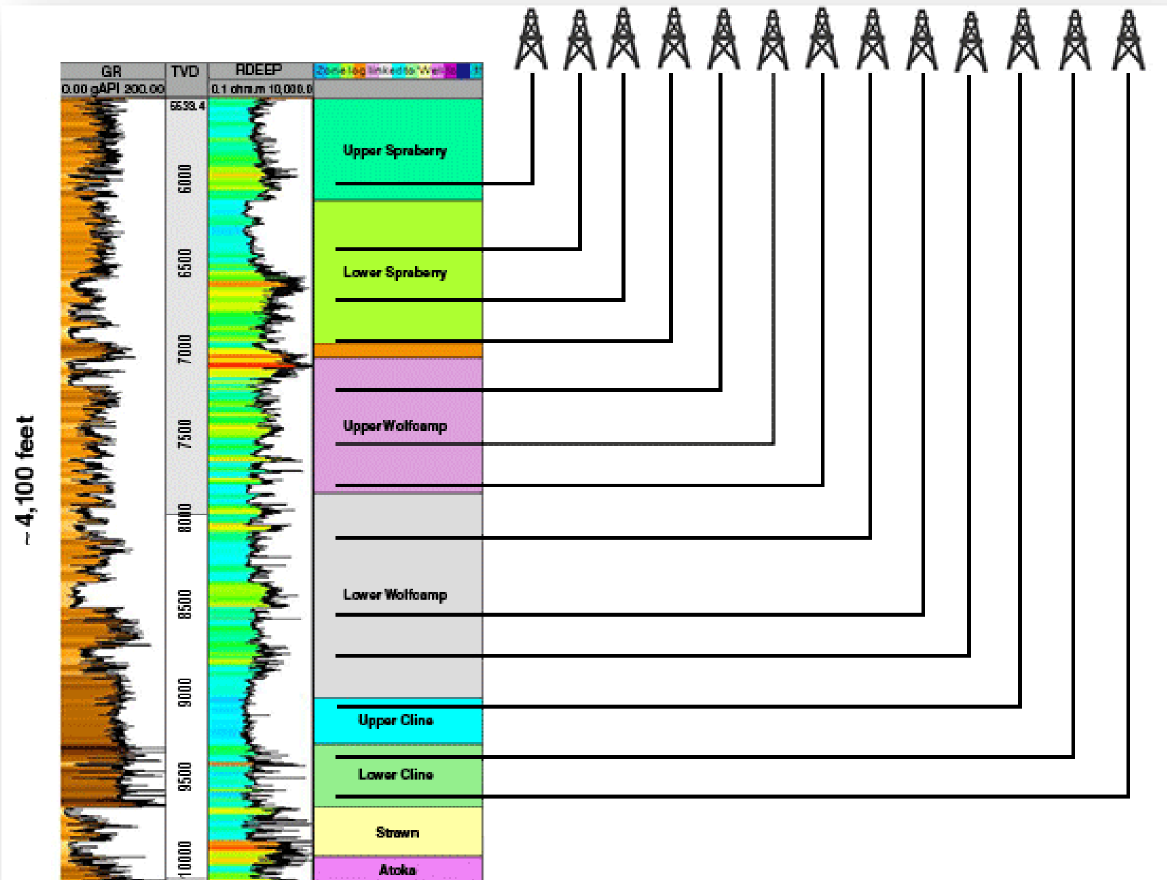

Figure 27: Stacked Spraberry, Wolfcamp, and Cline Plays in the Midland Basin

The concept behind stacked play development is centered on building a predictive 3-D model to determine the optimum vertical and lateral spacing for stacked play wells.[122] The model simulates

[121] Alimahomed, Farhan et al. 2018. Tapping Stacked Plays. The American oil & Gas Reporter. https://www.aogr.com/web-exclusives/exclusive-story/approach-optimizes-midland-basin-development (Accessed June 29, 2023).

[122] ibid

hydraulic fracturing of the stacked formation in an effort to predict the overall fracture footprint (**Figure 28**).[123,124]

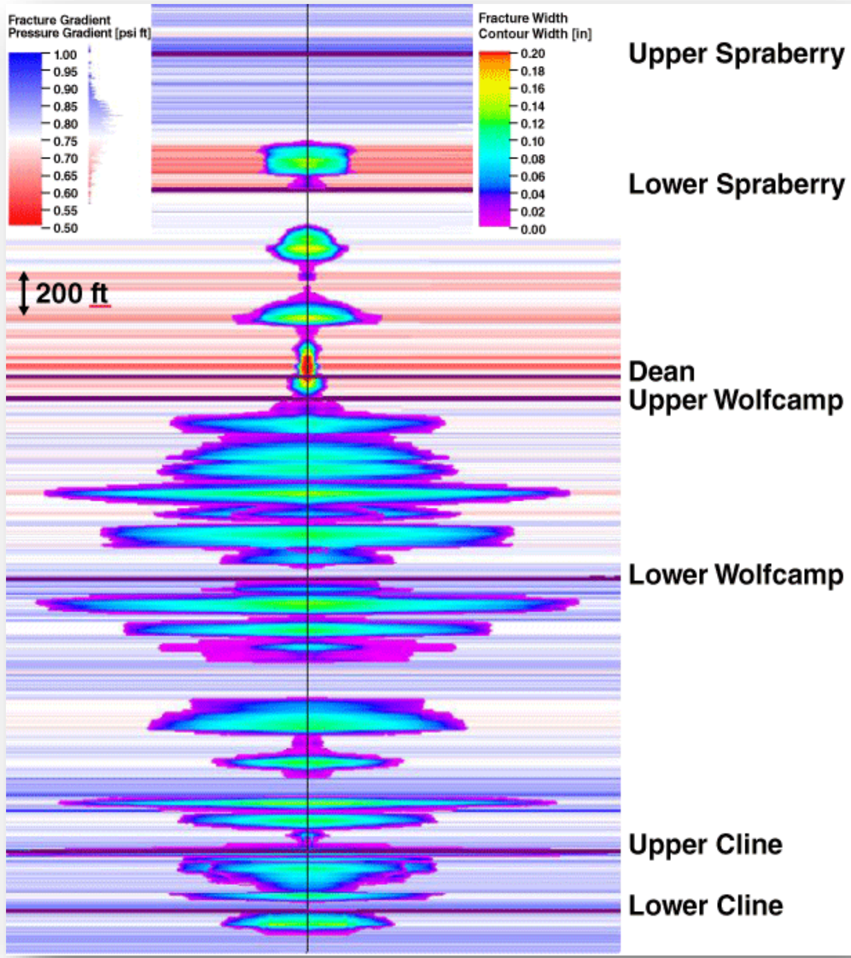

Figure 28: Geologic Model Showing the Fracture Footprint in a Stacked Play

Oklahoma's SCOOP and STACK trends consist of stacked limestone, shale, and carbonate formations (including the Oswego, Atoka, Morrow, Springer, Meramec, Osage, Woodford, Caney, Sycamore, and Hunton) [125] Newfield Exploration Company (now Ovintiv) was one of the first operators to produce from the STACK play in the Anadarko Basin beginning in 2013. Their Velta June pilot program, an infill drilling project, was a success with the goal of accessing producible stacked reservoirs using a 12-well-per- section spacing and cube development design (**Figure 29**).[126,127]

Devon Energy, also extensively developing in the STACK play, followed Newfield's strategy, focusing on the oil-saturated Meramec and liquids-rich Cana-Woodford plays.[128] Devon Energy's multi-stacked zone development included improved 3-D seismic interpretation, high-graded location selection, optimized

[123] Alimahomed, Farhan et al. 2018. Tapping Stacked Plays. The American oil & Gas Reporter. https://www.aogr.com/web-exclusives/exclusive-story/approach-optimizes-midland-basin-development (Accessed June 29, 2023).
[124] ibid
[125] Pickett, Al. 2018. Mid-Continent Update – New Play Concept "Merges" SCOOP and STACK Trends in Red-Hot Central Oklahoma. https://www.aogr.com/magazine/cover-story/new-play-concept-merges-scoop-and-stack-trends-in-red-hot-central-oklahoma (Accessed June 29, 2023)
[126] ibid
[127] Source: American Oil & Gas Reporter 2018. Mid-Continent Update.
[128] Devon Energy. 2023. Anadarko Basin. https://www.devonenergy.com/operations/anadarko-basin (Accessed June 30, 2023).

landing zones, geospatial optimization, cyber-geo-steering, flat in-zone wells, fiber optic sensing, prolonged drill-bit life, coiled tubing drill outs, and advanced fracture modeling. [129]

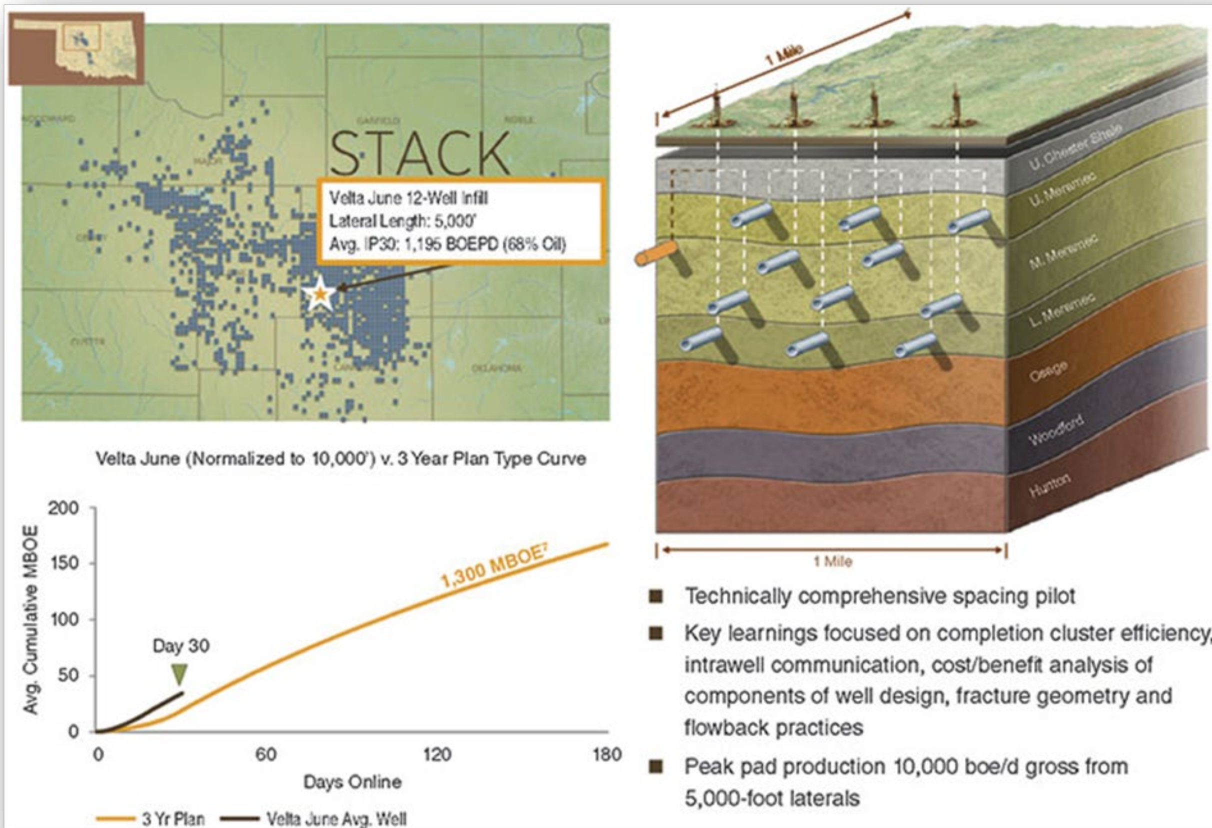

Figure 29: Newfield Exploration Company's STACK Velta June Pilot Development

Horizontal well spacing remains one of the critical questions facing operators in the stacked resource plays because it directly impacts initial well productivity and long-term recovery rates.[130] Drilling and development projects in both the Midland and Delaware basins have been up-spaced to increase the distance between horizontal wells on same or neighboring pads.[131] Changes to well layout and design have improved productivity and efficiency of unconventional resource developments.

[129] Pickett, Al. 2018. Mid-Continent Update – New Play Concept "Merges" SCOOP and STACK Trends in Red-Hot Central Oklahoma. https://www.aogr.com/magazine/cover-story/new-play-concept-merges-scoop-and-stack-trends-in-red-hot-central-oklahoma (Accessed June 29, 2023).
[130] Pickett, Al. 2020. Operators Keep 2020 Focus Fixed on Wolfcamp Play in Midland, Delaware Basins. The American oil & Gas Reporter. https://www.aogr.com/magazine/editors-choice/2020-operators-focus-on-wolfcamp-play (Accessed June 29, 2023).
[131] ibid

3.4 Produced Water Treatment and Beneficial Use

Legacy frac fluid chemistry designs primarily used fresh water from nearby available groundwater and surface water sources.[132] As the size of fracturing designs increased (increased lateral lengths and number of stages to frac), demand for fresh water increased. In tandem, volumes of PW increased as horizontal wells became more productive.

Early unconventional shale gas development occurred in the Marcellus region (Marcellus), where fresh water resources were reasonably abundant, but due to unfavorable subsurface geological characteristics, deep well disposal of PW into Class II injection wells proved difficult. Further, strict state regulatory requirements and a lack of public support made the installation of new disposal wells challenging and costly.

Fleets of water trucks were required to transport and dispose of the growing volumes of PW from Marcellus wells. In many instances, disposal wells were located hundreds of miles away from Marcellus wells, making operations significantly more expensive. As activity increased, fresh water costs and PW disposal fees grew rapidly, making management of the produced water one of the operators' largest expenses. Regarding costs, there is precious little reliable data related to the costs of managing produced water in the basins for a couple of reasons. One, is that there are so many variables in "Produced Water Management" that the costs of the entire process from company to company, job to job, and client to client varies on a myriad of factors (cost of timing, storage, specific treatment required, cost of construction of the in-field components, cost of constructing conveyance pipelines, cost of trucking, cost of utilities to pump water, cost of equipment, overhead costs, etc.). Secondly, costs are rarely openly shared between companies for competitive reasons, except for anecdotal and personal discussions where a company may reveal their average for SWD disposal runs, which again vary widely depending on inhouse versus commercial disposal. More research and focused industry cost data sharing is needed if treatment and disposal costs between basins are going to be compared.

Two different approaches emerged as the industry searched for the most cost-effective and sustainable solution to water sourcing for hydraulic fracturing. One approach was to develop and apply existing water treatment technologies to PW to make it meet a usable standard. This approach would require significant investment in water treatment infrastructure, but if proven successful, the process could potentially reduce the industry's reliance on fresh water and minimize the environmental impact of hydraulic fracturing.

The other approach, primarily promoted by operators, was to begin placing increasing pressure on stimulation service companies to modify their fracture treatment chemical components to use as much PW as possible in place of fresh water. This approach would require stimulation companies to develop new chemical formulations that could work effectively with PW. Slick Water (SW) frac fluid formulations have dramatically simplified the chemical composition and paved the way for the increasing volumes of PW to be used as make-up water. Collateral benefits of the slick water formulations include, reduced costs associated with chemical additives and flow back treatment, lower transportation costs, reduced

[132] Robert Rapier, 2017. How The Shale Boom Turned The World Upside Down, Forbes, April 21, 2017, Accessed on June 6, 2023 at https://www.forbes.com/sites/rrapier/2017/04/21/how-the-shale-boom-turned-the-world-upside-down/?sh=3ba778f377d2

potential environmental impacts, and most notably, suitability of a broader spectrum of water qualities compatible with the slick water chemical formulations.

While not exclusively used for all hydraulic fracturing, the use of SW has become more common across the industry as operators recognized the economic and environmental benefits. SW 's ability to allow the use of moderately treated PW in lieu of fresh water has a significant impact on the PW management challenge, in that the more PW that is reused, the less volume needs to be disposed and the demands on fresh water aquifers and surface features are reduced.

The cost of transporting water can negatively impact well economics, so a new industry of water midstream service companies emerged to handle these increasing volumes. However, concerns about the necessary scale of field development, water sourcing and disposal limitations, and the development of regulations that could dramatically impact the marketplace all impacted these midstream ventures.

When horizontal wells were first drilled in the Permian, PW was not recycled or transported via pipelines, nor was induced seismicity from wastewater injection a major concern. Production profiles with high water cuts, and increased completions activity combined with existing water production resulted in significant PW volumes and presented a unique water management dilemma.[133] For example, the Permian Basin generated many times more daily PW volumes than the other development regions, a deficit projected to increase in the future.[134] Recent estimates indicate PW reuse accounts for only 30 percent of the water used in completions.[135]

Current approaches to mitigate PW disposal focus on storage and reuse for hydraulic fracturing. Recycled water volumes are increasing, and additional storage capacity is needed to store large volumes of water for high-volume fracs. The transition of PW management to third-party, commercial water midstream companies is expected to continue as increasing PW volumes necessitate more storage and disposal capacity, and pipelines significantly reduce water volumes trucked to disposal wells. However, the industry and regulatory community are pushing for more beneficial reuse.[136] According to the recent GWPC *U.S. Produced Water Volumes and Management Practices in 2021* report, the amount of PW has increased by 6.02 percent over the previously studied amounts in 2017.[137] The cumulative volume of PW generated in 2021, according to the report, was 25,860,854,000 barrels (bbls). Texas remained in the top spot with nearly 10.0 billion bbls produced for the year, however ~1.9 billion bbls were reused for hydraulic fracturing operations.

The midstream water sector has already experienced some market consolidation, and that is expected to increase as water networks grow and positively impact the PW management market. Further challenges to overcome include induced seismicity from underground disposal, shallow and deep formation pressure increases, and increasing storage to facilitate larger buffer volumes to meet the need for water use surges that often occur during activities. Induced seismicity is also prompting regulatory changes and delaying permitting of additional injection wells. The reality is the volume of PW generated is significantly greater than the volume that can be used for in-field recycling. As a result, the

[133] ibid
[134] GWPC 2023. Produced Water Report 2023 - Regulations and Practices Update, May 2023
[135] ibid
[136] ibid
[137] GWPC 2022. U.S. Produced Water Volumes and Management Practices in 2021, November 2022.

industry continues to research and develop viable reuse options outside of the oil field. However, the high salinity and volume of PW often limits treatment and reuse viability. Water treatment capital and operating costs are also limiting factors, as desalination processes are costly. As a result, deep well injection remains the dominant method for the disposal of PW in the near term.

To assist operators with making reuse or recycling decision as well as infrastructure decisions for pipeline locations and added storage facilities the National Energy Technology Laboratory (NETL), in cooperation with the Lawrence Berkeley National Laboratory (LBNL), launched a PW optimization initiative to develop and deploy a framework called PARETO.[138] PARETO is specifically designed for PW management and beneficial reuse, it is a cutting-edge, open-source platform that supports informed and faster decision-making through analyzing both existing and proposed PW infrastructure. Therefore, the prevalent PW paradigm of handling, transporting, and disposing by deep well injection can be evaluated on a geographical basis so that PW fit-for-purpose treatment and reuse, as well as distribution and transportation of treated water and brine, can be considered between producers and midstream companies to provide industrial, agricultural, and municipal users with reliable water supplies. This requires both company-specific optimized PW treatment and reuse infrastructure development, coupled with regionally shared and managed infrastructure to maximize both PW reuse inside the oil and gas industry as well as overall regional and community PW reuse.

With regards to piping versus trucking, more data is needed from each basin to compare the relative adoption of pipelines over trucking; however, B3 recently reported a decline of ~6 percent in trucking in the Permian between early 2018 and late 2021.[139]

3.5 Frac Focus Reporting

The growth of unconventional oil and gas extraction has raised public concerns about potential environmental and health impacts. These concerns include potential impacts to groundwater, surface water, water supplies, and air quality. Modern, multi-stage fracturing techniques use upwards of 350,000 to 475,000 bbls of water and several million pounds of sand proppant. Chemical use generally makes up between 0.5 and 2 percent of the total frac-fluid volume, or between 70,000 to 150,000 gallons per well.

A number of oil and gas producing states have revised laws and regulations to address concerns about the disclosure of chemicals in fracture treatment fluid.

Many states require chemical disclosure for hydraulic fracturing. FracFocus was created in 2010 to make disclosure information more standardized and accessible. FracFocus is a disclosure website allowing operators to disclose the names, quantities, and concentrations of chemicals used in hydraulic fracturing designs that is required in many states.

Since its inception, FracFocus has continually sought additional input from states, the public, and technology and industry experts to improve chemical reporting data and make it more accessible to the general public. FracFocus has undergone two version upgrades, FracFocus 2.0 (2013) which improved

[138] Project PARETO, 2023. The Produced Water Optimization Initiative, accessed at https://www.project-pareto.org/ on August 30, 2023.

[139] Oilfield Water Connection Marcellus Shale Water Business Update Conference, Marcellus-Utica Produced Water Trends [Data Keynote], Kelly Bennett, Co-Founder and CEO, B3 Insight, June 29, 2022

data validation and allowed users to search for chemical information by date ranges, chemical names, or CAS numbers, and FracFocus 3.0 (2016) which improved data integrity, created a new data entry format, decreased the use of trade secrets, and established greater public transparency. The next version, FracFocus 4.0 is slated for release in 2023 and will enable the reporting of water used in hydraulic fracturing jobs by source (fresh, recycled, reused) and quality.

Today, FracFocus has received disclosures from more than 1,600 companies for more than 189,000 hydraulically fractured wells nationwide, and 27 states allow or require operators to disclose frac-fluid chemicals on the site.[140]

[140] FracFocus, 2023. About FracFocus, obtained on July 17, 2023, at https://www.fracfocus.org/learn/about-fracfocus

4 Regulatory Updates and Environmental Protection

Extracting oil and gas from productive formations produces several waste streams, and air pollution is of significant concern in light of the federal government's push to control climate change. Although emissions during various phases of exploration and production are singularly minor, the cumulative impact is of increasing social and political concern. Emission inventories of the oil and gas industry list the following as sources of air pollution:

Diesel Engines: Most drilling rigs have multiple diesel engines, and high volume hydraulic fracturing (HVHF) requires multiple diesel-engine powered pumps. Diesel-engine semi-trucks are commonly used to transport the drilling rig, completion equipment, and required materials such as water, proppant, and production equipment to and from the well site. Additionally, oil and produced water are commonly transported from location in trucks if no pipeline access is available. These engines generate methane, nitrogen dioxide (NOx), volatile organic compounds (VOC) and particulate matter (PM).

Venting/Flaring: Following well completion, regulatory authorities allow natural gas to be vented to the atmosphere or combusted in a flare. This process can be a significant source of VOCs, especially for wet gas wells.

Production Equipment: Artificial lift systems such as pumping units are required to bring production streams to the surface. Compressors are used to increase the pressure of produced gas enough to enter gathering lines. Often, these pumps and compressors are driven by natural gas powered engines which emit NOx, PM, and VOCs.

Storage Tanks and Vessels: Natural gas is separated on-site from the liquid phase of the production stream. The oil, condensates, and water separated from the gas phase are stored in steel or fiberglass tanks and vessels. Emissions from tanks and vessels can include the release of VOCs to the atmosphere during normal operations such as tank gauging.

Equipment Leaks: Production components can leak due to loss of fittings, cracks, or corrosion. Estimates of fugitive emissions from production equipment leaks vary, typically ranging from one to seven percent of total production depending on the interval.

4.1 Evolving Federal Air Quality Regulations

The oil and gas industry is the largest industrial source of methane and smog-forming VOCs in the U.S.[141] Since it was first established by executive order in 1970 by Richard Nixon, the Environmental Protection Agency (EPA) has promulgated a number of changes to air quality and environmental protection regulations and has gradually applied increasingly stringent requirements on the industry to reduce emissions and pollutants.

The New Source Performance Standards (NSPS) (40 CFR 60) and the National Emission Standards for Hazardous Air Pollutants (NESHAP) (40 CFR 63) are two major federal air regulatory programs applicable to industrial facilities in the U.S.

[141] "Basic Information about Oil and Natural Gas Air Pollution Standards." EPA, September 29, 2022. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/basic-information-about-oil-and-natural-gas

The term NSPS is used in the Clean Air Act Extension of 1970 (CAA) to refer to air pollution emission standards, and in the Clean Water Act (CWA) to refer to standards for water pollution discharges of industrial wastewater to surface waters. NSPS are pollution control standards that the EPA issues for new and modified sources of air and water pollution. NSPS are similar to NESHAP but require testing to confirm compliance. Engines, generators, and other industrial equipment have an NSPS. NSPS are designed to ensure that new and modified sources of pollution are equipped with the best available control technology (BACT) to reduce emissions to the lowest achievable rate. The standards are based on the best available scientific and engineering data and are updated periodically to reflect recent technologies and emission control methods. NSPS are a valuable tool for protecting air and water quality in the U.S. and have been effective in reducing emissions from a variety of sources, including power plants, factories, and oil and gas facilities. As a result, NSPS have helped to improve air quality and protect public health.

The NESHAP is a set of air pollution regulations designed to protect human health and the environment from emissions of hazardous air pollutants (HAPs). HAPs are a group of chemicals which can cause birth defects, cancer, and other health problems. NESHAP applies to certain industrial facilities that emit HAPs. The EPA has identified over 100 source categories subject to NESHAP, including petroleum refineries, chemical plants, and metal finishing facilities. Facilities subject to NESHAP must comply with the applicable standards. NESHAP standards can be either risk-based or technology-based. Risk-based standards are based on the health risk posed by a particular HAP. Technology-based standards are based on the BACT for controlling emissions of a HAP. Compliance is typically achieved by installing and operating air pollution control equipment. There are two types of facilities covered by NESHAPs: major and area sources.[142]

Criteria pollutants are pollutants determined by the EPA to be hazardous to human health. The term *criteria pollutants* come from the requirement that EPA describe the pollutants' characteristics and potential health and welfare effects. Air quality standards are established based on these criteria.

Carbon monoxide (CO) is a colorless, odorless gas produced by the combustion of fossil fuels. CO can reduce the amount of oxygen that the blood can carry, which can lead to health problems such as dizziness, headaches, and nausea. In high concentrations, CO can be fatal.

Lead (Pb) is a heavy metal that can be harmful to the nervous system, especially in children. Lead can also cause reproductive problems and damage to the kidneys and liver.

Nitrogen oxides (NOx) are gases produced when fossil fuels are burned at high temperatures. NOx can react with other pollutants in the atmosphere to form smog, which can cause respiratory problems such as asthma and bronchitis.

Ozone (O3) is a gas formed when NOx and VOCs react in the presence of sunlight. Ozone can irritate the lungs and worsen asthma symptoms. It can also damage plants and reduce visibility.

Particulate matter (PM) is a mixture of solid particles and liquid droplets suspended in the air. PM can be made up of a variety of materials, including dust, dirt, soot, and smoke. PM can irritate the lungs and worsen asthma symptoms. It can also increase the risk of heart disease and stroke.

[142] "Federal Rules: NESHAP and NSPS." Minnesota Pollution Control Agency, 2023. https://www.pca.state.mn.us/business-with-us/federal-rules-neshap-and-nsps#:~:text=New%20Source%20Performance%20Standards%20(NSPS,dry%20cleaners%20all%20have%20NSPS

Sulfur dioxide (SO_2) is a gas produced when sulfur-containing fuels are burned. SO_2 can cause respiratory problems such as asthma and bronchitis. It can also damage plants and buildings.

The National Ambient Air Quality Standards (NAAQS) (40 CFR 50), the Greenhouse Gas Reporting Program (GHGRP) (40 CFR 98), and the New Source Review (NSR) Permits (40 CFR 51-52) are other federal regulations which protect air quality in the U.S. The National Ambient Air Quality Standards (NAAQS) are a set of standards that define levels of air quality necessary to protect public health and welfare. The NAAQS are divided into two categories: primary standards and secondary standards. Primary standards are designed to protect public health, while secondary standards are designed to protect public welfare, such as visibility. The EPA has established NAAQS for the criteria pollutants. States are required to develop and implement plans to achieve and maintain the NAAQS. The GHGRP is a federal program that requires large sources of greenhouse gas emissions to report their emissions annually. The GHGRP covers a variety of sources, including onshore petroleum and natural gas production wells and related equipment. The NSR Permits are required for new stationary sources of air pollution. NSR permits are designed to ensure new sources meet the requirements of the Clean Air Act and do not contribute to air pollution problems in the surrounding area.

In 1985, the EPA regulated the oil and gas industry for the first time by issuing a NSPS (50 FR, June 24 1985) which covered the processing and transmission of oil and natural gas.[143] The Clean Air Act Amendments of 1990 promulgated NESHAP for oil and gas production facilities, which sets standards for HAPs from stationary sources.[144] These standards were designed to reduce emissions of HAPs from oil and natural gas production facilities, including benzene, toluene, ethylbenzene, and mixed xylenes (BTEX), as well as n-hexane.

It was not until 1999 that EPA proposed NESHAP apply to all oil and gas production facilities.[145] In 2007, the EPA finalized and implemented the NESHAP for oil and gas production facilities.[146]

Before the coupling of HVHF with directional drilling began, the quantity of emissions generated by the oil and gas industry was considerably less. Shallow wells were typically drilled vertically and did not require HVHF as a means of stimulation. Federal air regulations had mainly focused on midstream and processing operations, while individual states generally exempted oil and gas operations from permitting and operating requirements.[147] Additionally, at that time there was no established framework for regulating GHG emissions, particularly methane emissions. However, sustained reliance on hydrocarbon energy, and increased development of directionally drilled wells stimulated with HVHF, led to increased emissions from oil and gas drilling and production operations, resulting in the increased release of a variety of pollutants into the air, including VOCs, methane, and NOx.

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[143] Seguljic, Thomas S. "Evolving Air Regulations Are Causing Inconsistencies across the Marcellus Shale Basin." OnePetro, October 13, 2015. https://onepetro.org/SPEERM/proceedings/15ERM/All-15ERM/SPE-177289-MS/184244

[144] U.S. Environmental Protection Agency. Fact Sheet Final Air Toxics Rules for Oil and Natural Gas Production Facilities, And Natural Gas Transmission and Storage Facilities, May 14, 1999. https://www.epa.gov/sites/default/files/2016-02/documents/natural_gas_transmission_fact_sheet_1999.pdf

[145] Federal Register / Vol. 64, No. 116 /Thursday, June 17, 1999 /Rules and Regulations, June 17, 1999. https://www.govinfo.gov/content/pkg/FR-1999-06-17/pdf/99-12894.pdf

[146] Federal Register, Vol. 72, No.1, January 3, 2007. National Emission Standards for; Hazardous Air Pollutants for Source Categories From Oil and Natural Gas Production Facilities, https://www.govinfo.gov/content/pkg/FR-2007-01-03/pdf/E6-22413.pdf

[147] Seguljic, Thomas S. "Evolving Air Regulations Are Causing Inconsistencies across the Marcellus Shale Basin." OnePetro, October 13, 2015. https://onepetro.org/SPEERM/proceedings/15ERM/All-15ERM/SPE-177289-MS/184244

Beginning in 2012, the EPA and some states began issuing additional regulations specifically targeting air emissions from oil and gas production operations. Increased development of the Marcellus Shale had exceeded the emission rate exemptions previously set by state regulatory agencies in Ohio[148] and West Virginia.[149] Pennsylvania chose to eliminate permitting exemptions[150] for oil and gas wells. In 2012, the EPA finalized the NSPS and NESHAP reviews for the oil and natural gas sector. These standards were designed to reduce emissions of HAPs from oil and natural gas production, transmission, and storage facilities. The rules applied to new and existing sources, including wells, pipelines, and processing facilities. The rules set standards for emissions of HAPs from a variety of sources, including equipment leaks, glycol dehydration units, and storage vessels. The rule sets standards for emissions of VOCs from a variety of sources, including equipment leaks, valves, and pumps. The rule applies to new and existing sources, including pipelines, compressor stations, and storage facilities.[151]

In 2016, the EPA amended the NSPS for the oil and natural gas industry. The amended standards set limits on the amount of air pollution that could be emitted from new and modified oil and gas sources. The amended NSPS included more stringent requirements for methane emissions, as well as requirements for other pollutants such as VOCs and benzene.

On March 1, 2018, the EPA amended narrow portions of the fugitive emissions requirements in the 2016 NSPS. These amendments were made in response to concerns from industry about the compliance burden of the original requirements. The amendments focused on two specific requirements; 1) leaking components be repaired during unplanned or emergency shutdowns, and 2) the monitoring survey requirements for well sites located on the Alaskan North Slope be implemented.[152]

On August 13, 2020, the EPA published two final rules that would create a simpler and less difficult setting for the oil and natural gas industry to conform with the NSPS. These rules comprised policy adjustments to the 2012 and 2016 NSPS, and technical amendments to the 2012 NSPS. The policy amendments clarified the requirements of the NSPS and made them more flexible. The technical amendments updated the NSPS to reflect changes in technology and industry practices.[153]

On June 30, 2021, President Biden signed into law a joint Congressional resolution disapproving the August 13, 2020, final policy amendments to EPA's 2012 and 2016 NSPS. This resolution effectively reversed the August 13, 2020, policy amendments, and the original requirements of the NSPS went back

[148] General permits - oil and gas well-site production operations - Ohio. Accessed June 16, 2023. https://epa.ohio.gov/divisions-and-offices/air-pollution-control/permitting/general-permits-oil-and-gas-well-site-production-operations

[149] “For the Prevention and Control of Air Pollution in Regard to the Construction, Modification, Relocation, Administrative Update and Operation of Oil and Natural Gas Production Facilities Located at the Well Site.” West Virginia Department of Environmental Protection, October 18, 2013. https://dep.wv.gov/daq/permitting/Documents/GeneralPermits/G70-AResponsetoPublicComment.pdf

[150] Macoskey, Kristian. “Pennsylvania Oil and Gas Air Quality Regulatory Update.” Civil & Environmental Consultants, Inc., January 4, 2012. https://www.cecinc.com/blog/2012/01/04/pennsylvania-oil-and-gas-air-quality-regulatory-update/

[151] “2012 Final Rules for Oil and Natural Gas Industry.” EPA, April 17, 2012. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/2012-final-rules-oil-and-natural-gas

[152] “Amendments to the New Source Performance Standards for the Oil and Natural Gas Industry.” EPA, March 1, 2018. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/amendments-new-source-performance-standards

[153] “EPA Issues Final Policy and Technical Amendments to the New Source Performance Standards for the Oil and Natural Gas Industry.” EPA, August 13, 2020. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-final-policy-and-technical

into effect.[154] In November of 2021, the EPA proposed new source performance standards updates, emissions guidelines to reduce methane and other harmful pollution from the oil and natural gas industry. These proposed rules would further reduce methane emissions from the industry, as well as emissions of other pollutants such as VOCs and benzene.[155] In November of 2022, the EPA proposed to update, strengthen, and expand its November 2021 proposal. These proposed rules would go even further than the previous proposal in reducing methane and other harmful emissions from the industry.[156]

Federal air quality programs regulations affecting the oil and gas industry are listed in **Table 2.**

Table 2: Federal Air Quality Regulations	
New Source Performance Standards (40 CFR Part 60)	
Subparts K, Ka, and Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels)
Subpart GG	Standards of Performance for Stationary Gas Turbines
Subpart KKK	Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants
Subpart LLL	Standards of Performance for SO_2 Emissions from Onshore Natural Gas Processing Plants
Subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines
Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines
Subpart KKKK	Standards of Performance for Stationary Combustion Turbines
Subpart OOOO and OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities

[154] U.S. Environmental Protection Agency. Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule, June 30, 2021. https://www.epa.gov/system/files/documents/2021-07/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf.

[155] Environmental Protection Agency. "EPA Proposes New Source Performance Standards Updates, Emissions Guidelines to Reduce Methane and Other Harmful Pollution from the Oil and Natural Gas Industry." Controlling Air Pollution from the Oil and Natural Gas Industry, November 2, 2021. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-proposes-new-source-performance.

[156] Environmental Protection Agency. "EPA Issues Supplemental Proposal to Reduce Methane and Other Harmful Pollution from Oil and Natural Gas Operations." Controlling Air Pollution from the Oil and Natural Gas Industry, November 11, 2022. https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/epa-issues-supplemental-proposal-reduce

Table 2: Federal Air Quality Regulations (continued)	
National Emission Standards for Hazardous Pollutants (40 CFR Part 63)	
Subpart H	National Emission Standards for Organic Hazardous Air Pollutants for Equipment Leaks
Subpart HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities
Subpart VV	National Emission Standards for Oil-Water Separators and Organic-Water Separators
Subpart HHH	National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities
Subpart YYYY	National Emission Standards for Hazardous Air Pollutants for Stationary Combustion Turbines
Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines
National Ambient Air Quality Standards (40 CFR Part 50)	
Greenhouse Gas Reporting Program (40 CFR Part 98)	
New Source Review Permits (40 CFR Parts 51-52)	

4.1.1 State, Tribal, and Local Regulation Changes Since 2009

There have been a number of state, tribal, and local regulation changes since 2009. For example, beginning in 2008, towns and counties in New York used zoning ordinances to impose local moratoriums on HVHF. [157] In 2010, the governor of New York imposed a six-month moratorium on HVHF, its removal contingent on the completion of an environmental impact review by the state environmental agency. In 2014, the moratorium was made permanent.[158]

In 2017, the California Air Resources Board (CARB) issued the Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities.[159] The regulation was designed to decrease methane emissions from oil and gas production, processing, storage, and transmission compressor stations by requiring oil and gas producers to address fugitive and vented emissions of methane from new and existing oil and gas facilities. Fugitive emissions occur when methane leaks from equipment or infrastructure. Vented emissions are intentionally released from equipment or infrastructure during normal operations. The regulation requires oil and gas producers to develop emission control plans, conduct leak testing, and repair leaks. The regulation also requires oil and gas producers to report their methane emissions to CARB. CARB estimates that compliance with these regulations will reduce methane emissions by over 1,000,000 tons annually.[160]

In May 2019, EPA issued final amendments to the 2016 federal implementation plan to manage air emissions from new and modified real minor oil and natural gas sources located on the Uintah and

[157] Plumer, Brad. 2014. "After years of debate, New York State will ban fracking." Vox, December 17, 2014. https://www.vox.com/2014/12/17/7409939/fracking-new-york.
[158] Sadasivam, Naveena. "New York State of Fracking: A ProPublica Explainer." ProPublica, July 22, 2014. https://www.propublica.org/article/new-york-state-of-fracking-a-propublica-explainer.
[159] "California Air Resources Board." Oil and Gas Methane Regulation | California Air Resources Board, March 2017. https://ww2.arb.ca.gov/resources/fact-sheets/oil-and-gas-methane-regulation.
[160] California Climate Policy Fact Sheet Methane, November 2019. https://www.law.berkeley.edu/wp-content/uploads/2019/11/Fact-Sheet-Methane.pdf.

Ouray Indian Reservation in Utah. The amendments were enacted due to portions of the reservation being designated as nonattainment for the 2015 National Ambient Air Quality Standards for ozone.

4.1.2 Improvements in Industry Related Emissions

Annual reported GHG emissions from the petroleum and natural gas sectors have been holding steady or reducing over time. In 2016, GHG emissions from the sectors totaled 277 million metric tons of CO_2e (carbon dioxide equivalent).[161] This number increased steadily in 2017 and 2018, at 288 million metric tons and 317 million metric tons, respectively.[162] In 2019, CO_2 emissions from the petroleum and natural gas sectors increased to 347 million metric tons.[163] This increase was likely due to a number of factors, including the growth of the oil and gas industry and the increasing use of HVHF. **Figure 30** shows the emission trend for the petroleum and natural gas industry by subsector.[164]

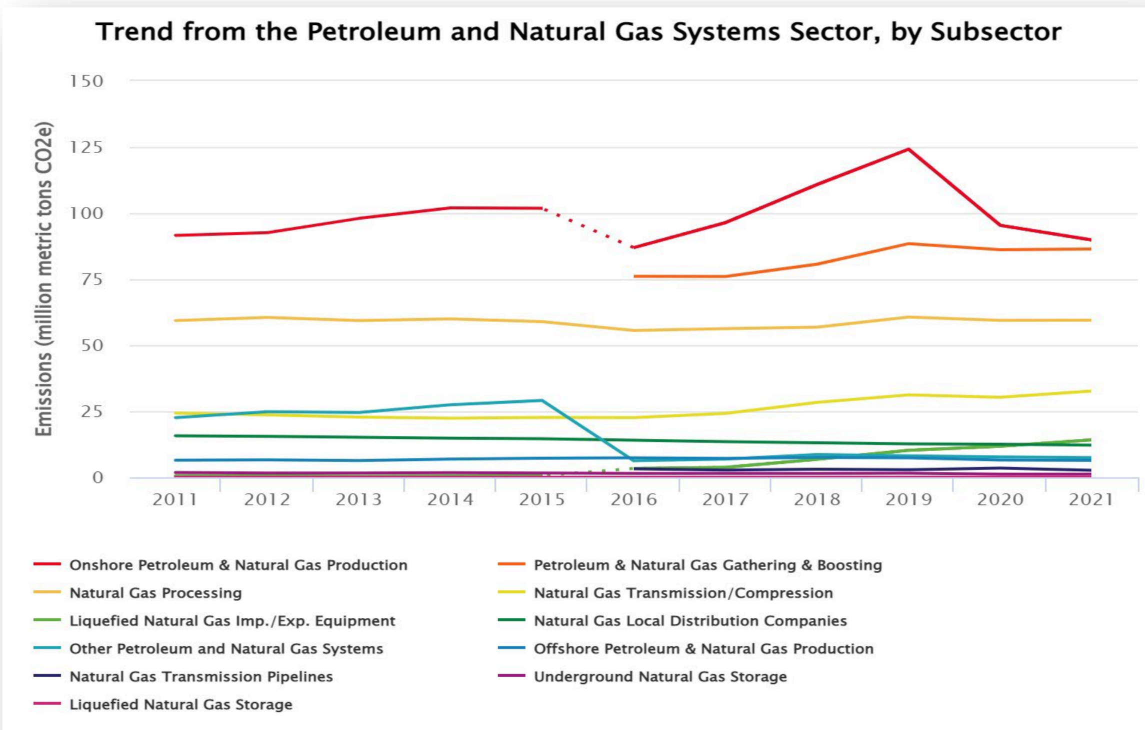

Figure 30: Emission Trend for the Petroleum and Natural Gas System

Since 2019, however, GHG emissions from the petroleum and natural gas sectors have declined. In 2020, CO_2 emissions totaled 314 million metric tons, and in 2021, they fell to 312 million metric tons.[165] This decrease is likely due to a number of considerations, including the COVID-19 pandemic, which led to a

[161] Greenhouse Gas Reporting Program (GHGRP). GHGRP Petroleum and Natural Gas Systems, October 17, 2022. https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems#trends-subsector.

[162] Ibid.

[163] Ibid.

[164] Source EPA Greenhouse Gas Reporting Program 2022

[165] Greenhouse Gas Reporting Program (GHGRP). GHGRP Petroleum and Natural Gas Systems, October 17, 2022. https://www.epa.gov/ghgreporting/ghgrp-petroleum-and-natural-gas-systems#trends-subsector.

reduction in energy demand, electrification of some equipment such as drilling rigs and hydraulic fracturing pumps, and the implementation of new regulations designed to reduce emissions.

Regardless, the decline in CO_2 emissions from the petroleum and natural gas sectors is a positive development, suggesting that the efforts to reduce emissions from these sectors are working. However, it is important to note GHG emissions from these sectors still represent a significant portion of total GHG emissions in the U.S. In 2021, petroleum accounted for about 36 percent of U.S. energy consumption, but petroleum was the source of 46 percent of total annual U.S. energy-related CO_2 emissions. [166] Natural gas also provided about 32 percent U.S. energy and accounted for 34 percent of total annual energy-related CO_2 emissions. Coal was the source of about 12 percent of U.S. energy use and about 21 percent of total annual energy-related CO_2 emissions.[167]

Sustaining a decline in CO_2 emissions from industry will depend on continued implementation of new regulations, the innovative use of electric rigs and other equipment, the growth of renewable energy sources, and the demand for energy. However, the current trend is encouraging, and suggests the U.S. is making progress in reducing industry emissions.

Regional emissions studies can be used to identify the sources of emissions, track trends in emissions over time, and develop strategies to reduce emissions. These inventories are typically compiled using data from government agencies, industry, and environmental groups. Models specific to regions can then be used to estimate emissions from specific sources or simulate the transport of pollutants through the atmosphere. Monitoring stations can be used to measure the concentrations of pollutants in the air. This data can be used to track trends in emissions over time and identify areas where emissions are high. Broadly, regional emissions studies can be used to inform a variety of decisions, including air quality planning and environmental impact assessment.

Examples of regional emissions studies include the Regional Greenhouse Gas Initiative (RGGI) and the California Air Resources Board. The RGGI is a collaborative endeavor among 12 eastern states to reduce CO_2 emissions from power plants in Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Virginia. Together, these states have instituted a regional cap on CO_2 emissions from regulated power plants. Over time, the regional cap declines, so that CO_2 emissions are decreased in a planned and predictable way. Since its inception, RGGI emissions have been reduced by more than 50 percent—twice as fast as the nation as a whole.[168]

CARB has an extensive GHG research program to measure and monitor the regional and local emission sources of important GHGs in California. CARB initiated the first subnational GHG monitoring network in 2010 to study the regional GHG emissions trends throughout the state and evaluate regional and statewide inventories. The network currently has seven CARB-operated monitoring stations at strategically selected sites throughout California. In addition, CARB collaborates with a number of research partners on other monitoring locations throughout the state. CARB is also adopting analyzers

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166 "U.S. Energy Information Administration - EIA - Independent Statistics and Analysis." Where greenhouse gases come from - U.S. Energy Information Administration (EIA), June 24, 2022. https://www.eia.gov/energyexplained/energy-and-the-environment/where-greenhouse-gases-come-from.php.

167 Ibid.

168 The Regional Greenhouse Gas Initiative, 2023. Elements of RGGI, accessed July 25, 2023 at https://www.rggi.org/program-overview-and-design/elements

capable of determining the isotopic signature of CO_2 and methane to further improve the source attribution of the inventory. Data from this network are used in several research studies and formed the basis of a thorough statewide inverse receptor-oriented modeling, and various trends assessment analyses, to support the statewide GHG inventory.

Regional emissions studies detailed findings in major oil- and gas-producing areas in which biogenic vs. thermogenic methane sources were differentiated, smaller sources not included in the EPA inventory were monitored, and particularly leaky equipment was identified. Location-specific studies have been a major research focus in recent years. For example, a study of seven oil-and gas-producing regions in the U.S. found higher methane emissions in mainly oil-producing areas than in mainly gas-producing areas. This in part reflects the fact that oil may contain some methane that can escape from oil storage tank vents and other openings.

Regional emissions studies in the Barnett Shale of Dallas Fort Worth, Texas, showed 67 percent of methane emissions are from oil and gas sources. Half of all oil and gas methane emissions in this area come from just 2 percent of production, processing, and transportation facilities, and 90 percent of emissions come from just 10 percent of facilities.[169] Studies of this nature provide insight and perspective on potential sources of local or regional emissions that could be reduced or mitigated in the future.

4.1.2.1 Increased Use of Electric

As investors and regulators push the oil and gas industry to lower its carbon emissions, the development of electric drill rigs and hydraulic fracturing pumps will become more prevalent. In fact, several operators have already taken step to electrify their operations. In 2012, Chesapeake presented a drilling rig electrification project for their Barnett exploration that used mobile transformer skids to run diesel-electric rigs on grid power.[170] Chesapeake ultimately deployed seven transformers and a dozen rigs capable of utilizing the skids or connecting to the power grid and indicated that they planned to drill 850 wells on electricity. Each electric rig was estimated to reduce CO_2 emissions by approximately 4.2 tons/day, as well as 4.6 tons per well of NOx, and 0.2 tons per well of VOCs.

More recently, in states with stringent emission regulations such as Colorado, operators are implementing rigs capable of running largely on the electric grid. Civitas Resources, Colorado's largest oil and gas producer, has used electric drill rigs at their pads in a Denver suburb and are realizing reduced emissions coupled with the elimination of diesel fuel truck deliveries and much decreased noise levels.[171] Civitas' Chief Sustainability Officer, Brian Cain, did caution that this is achievable because they have access to power lines that have been built in the urban expansion, and that the landscape is a lot different in more rural areas that do not have easy access to adequate electric power. The use of electricity to cut drilling emissions is a good tactic, however, there are obstacles to overcome, such as adjusted work shifts to reduce the impact on the grid during peak usage times.

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[169] Allison, E., and Mandler, B. 2018. Methane Emissions in the Oil & Gas Industry – Quantifying emissions and distinguishing between different methane sources, AGI, Petroleum and the Environment Part 19.

[170] Stricklin, R., 2012. Drilling Rig Electrification – Barnett and Beyond, presented at the AADE Technical Symposium, 2012.

[171] Hampton, L., 2021. Focus: Oil driller sees the industry's future in electric rigs, carbon offsets, Reuters., accessed at https://www.reuters.com/markets/commodities/oil-driller-sees-industrys-future-electric-rigs-carbon-offsets-2021-12-20/ on August 29, 2023.

Other operators such as Pioneer Natural Resources, have plans to electrify drilling, hydraulic fracturing, and compression at pump stations throughout Texas within the next six to eight years. Pioneer began switching compression at pumping stations to electric in 2021.[172] Additionally, Halliburton has used grid-powered fracturing operations beginning also in 2021, and realized dramatically reduced CO_2 emissions.[173] Finally, Caterpillar Oil & Gas is developing ways to help operators meet reduced CO_2 emissions with a new system that captures and uses flare gas to generate electricity. Their system consists of multiple 1-MW Cat® G3512 generators fueled by natural gas that are paired with lithium-ion batteries to store the energy.[174]

4.1.2.2 API Environmental Partnership

The API Environmental Partnership is an organization formed in December of 2017 that is comprised of U.S. oil and natural gas companies of all sizes that are committed to continuously improving the industry's environmental performance.[175] The improvements are centered on building upon their knowledge to implement measures that are technically feasible, commercially proven, and will result in dramatic emissions reductions. The members act through six environmental performance programs designed to reduce methane and VOC emissions: 1) Leak Detection and Repair, 2) Focus on High-Bleed Pneumatic Controllers, 3) Improving the Manual Liquids Unloading Process, 4) Compressor Program, 5) Pipeline Blowdown Program, and 6) Flare Management Program.

The members also maintain staff who learn the most recent advances and best practices from subject matter experts that can foster continued reductions of their cumulative environmental impacts. Based on their performance and lesson learned, members collaborate with one another by sharing scientific data and results of their implementation efforts at Partnership hosted workshops and conferences. In the latest Annual Report for 2022 the Partnership has reported their combined efforts to monitor, survey, inspect, and implement reduction practices, as well as data regarding their results such as:[176]

- <1 component leaking per 2,000 (0.05% leak occurrence rate),
- Gas driven controllers replaced or removed (>22,400),
- Approved emissions reduction practices utilized on more than 1,500 compressors, and
- A 45 percent reduction in flare intensity and a 26 percent reduction in total flare volumes from 2021 to 2022.

The participation of oil and gas companies has grown from the initial 23 in 2017, to over 102 in 2023, representing greater than 70 percent of the U.S. onshore oil and natural gas production in 47 states.

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[172] ibid

[173] ibid

[174] Morrison, J. 2021. The next generation of land drilling: Hybrid-powered rig combined with energy storage., Accessed at https://www.worldoil.com/magazine/2021/march-2021/features/the-next-generation-of-land-drilling-hybrid-powered-rig-combined-with-energy-storage/ on August 29, 2023.

[175] The Environmental Partnership, 2019. Accessed at https://theenvironmentalpartnership.org/ on August 30, 2023.

[176] ibid

4.1.3 EPA Greenhouse Gas Inventory

According to the 2018 and 2020 U.S. EPA Inventory of U.S. GHG Emissions and Sinks,[177,178] energy-related activities were the primary sources of U.S. anthropogenic GHG emissions, accounting for the following percentages:

- 2018: 83.1 percent of total GHG emissions on a CO_2e basis. This included 97 percent CO_2, 40 percent methane (CH_4), and 10 percent nitrous oxide (N_2O).
- 2020: 81.2 percent of total GHG emissions on a CO_2 equivalent basis. This included 96.4 percent CO_2, 41.4 percent CH_4, and 9.6 percent N_2O.

Methane emissions from energy sources identified as either natural gas systems or petroleum systems from 1990 through 2020 are presented in **Table 3**.[179] Methane emissions declined for both sources over this 30-year period. These reductions in CH_4 emissions are essentially due to decreases in emissions from distribution, transmission, and storage. The decrease in distribution emissions is from reduced pipeline and distribution station leaks, and the decrease in transmission and storage emissions is principally from diminished compressor station emissions (including emissions from compressors and equipment leaks).

Table 3: Methane Emissions from Energy (MMT CO_2e.)

Source	1990	2005	2016	2017	2018	2019	2020
Natural Gas Systems	195.5	177.5	165.2	166.6	171.8	172.1	164.9
Petroleum Systems	47.8	41.4	40.4	40.5	38.6	40.4	40.2

4.2 Surface and Groundwater Protection

"Waters of the United States" (WOTUS) is a threshold term in the CWA that establishes the geographic scope of federal jurisdiction as authorized by the Act.[180] A threshold term is a term that determines whether or not something is subject to a rule or regulation. In this context, the threshold terms are used to determine whether or not a particular body of water is subject to regulation under the CWA. The CWA does not specifically define WOTUS, instead giving the EPA and the U.S. Army Corps of Engineers (USACE) the authority to define WOTUS in regulations.

The definition of WOTUS has been a source of debate since it was promulgated by the CWA in 1972. In 2006, the Supreme Court issued a decision in Rapanos v. United States that created a two-part test for determining whether a water is a WOTUS. Under the Rapanos test, a water is a WOTUS if it is:

- A traditional navigable water, or
- A relatively permanent, standing or continuously flowing body of water that:

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[177] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018, accessed on March 10, 2023 at https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2018

[178] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020, accessed on March 10, 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020 – Main Text (epa.gov)

[179] U.S. EPA, Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020, accessed on March 10, 2023 Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2020 – Main Text (epa.gov)

[180] EPA. Waters of the United States: History of Waters of the United States. https://www.epa.gov/wotus/about-waters-united-states. Access on February 1, 2023.

- Is connected to a traditional navigable water, or
- Is used or could be used for interstate or foreign commerce.

The Rapanos test was widely criticized by environmental groups, who argued that it was too narrow and excluded many waters that should be protected under the CWA. In response, the EPA and the USACE issued a rule in 2015 that attempted to clarify the definition of WOTUS. The 2015 rule adopted a "significant nexus" test, which would have expanded the definition of WOTUS to include many more waters that were not covered under the Rapanos test.

The 2015 rule was challenged in court, and in 2019, the Supreme Court issued a decision in Sackett v. EPA that vacated the rule. The Court held that the EPA and USACE had exceeded their authority under the CWA by adopting the significant nexus test.

Following the Sackett decision, the EPA and USACE have not issued a new rule defining WOTUS. Instead, they are currently operating under a default definition that was established in 2010. This default definition is based on the Rapanos test, but it includes a number of clarifications that were issued by the EPA and USACE in 2015.

In 2020, the EPA and USACE issued a new proposed rule that would define WOTUS more narrowly than the 2015 rule. This proposed rule has also been challenged in court, and it is currently being litigated. The 2015 rule expanded the definition of "jurisdiction" waters and increased activities requiring permits under the CWA, Section 402 National Pollutant Discharge Elimination System (NPDES) and Section 404 (wetland) programs.[181] The effects of these new rules impacted varying industries, to include oil & gas development, as some of the rules were unclear as how to define WOTUS or how to test for WOTUS from a methodology perspective. For these reasons, on October 22, 2019, the EPA and the USACE published a final rule to repeal the 2015 Rule, which reinstated and re-codified the regulatory text that existed prior to the 2015 Rule.

The agencies later replaced the 2019 Rule with the Navigable Waters Protection Rule (NWPR) in 2020. However, in response to a U.S. District Court case in 2021, the U. S. EPA and the USACE remanded the 2020 NWPR and began interpreting WOTUS consistent with the pre-2015 regulatory regime. The WOTUS definition was revised again on December 30, 2022, and then again on August 29, 2023, to conform with a U.S. Supreme Court decision. The newly amended changes primarily included removal of the significant nexus standard and clarified interstate wetlands. The newly amended rules include the following definitions and exemptions as identified in **Table 4**:[182]

[181] EPA. Waters of the United States: History of Waters of the United States. https://www.epa.gov/wotus/about-waters-united-states, access on February 1, 2023

[182] Federal Register. EPA, 40 CFR Part 120. Revised definition of "Waters of the United States."

Table 4: WOTUS Definitions Effective March 20, 2023

WOTUS Definitions	WOTUS Exemptions
Traditional navigable waters the territorial seas, and interstate waters.	Waste treatment systems, including treatment ponds or lagoons, designed to meet the requirements of the Clean Water Act.
Impoundments of "Waters of the United States"	Prior converted cropland designated by the Secretary of Agriculture.
Tributaries to traditional navigable waters, the territorial seas, interstate waters, impoundments when the tributaries meet the relatively permanent standard.	Ditches (including roadside ditches) excavated wholly in and draining only dry land and that do not carry a relatively permanent flow of water.
Wetlands with a continuous surface connection to relatively permanent impoundments or to jurisdictional tributaries when the jurisdictional tributaries meet the relatively permanent standard.	Artificially irrigated areas that would revert to dry land if the irrigation ceased.
	Artificial lakes or ponds created by excavating or diking dry land to collect and retain water and which are used exclusively for such purposes as stock watering, irrigation, settling basins, or rice growing.
Intrastate lakes and ponds, streams, or wetlands that meet the relatively permanent standard.	Artificial reflecting or swimming pools or other small ornamental bodies of water created by excavating or diking dry land to retain water for primarily aesthetic reasons.
	Waterfilled depressions created in dry land incidental to construction activity and pits excavated in dry land until the construction or excavation operation is abandoned and the resulting body of water meets the definition of WOTUS.
	Swales and erosional features (e.g., gullies, small washes).

4.3 Endangered Species and Conservation Efforts

Congress passed the Endangered Species Act (ESA) in 1973 to conserve endangered and threatened species and their habitats. Endangered species are considered to be in danger of extinction throughout all or a significant portion of their range; whereas, threatened species are likely to become endangered in the near future throughout all or a large portion of their range. According to the U.S. Fish and Wildlife Service (USFWS), since 1967 there have been 1,701 species listed as threatened or endangered under the ESA 1973 (with amendments) and its precursors (Endangered Species Preservation Act of 1966 and Endangered Species Conservation Act of 1969).[183] Currently, there are approximately 1,300 species listed under the ESA as the status of some species has changed and have since been delisted.[184] The National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NMFS) and the Department of the Interior's USFWS share responsibility for implementing the ESA.

Since 2010, the USFWS has listed 368 species (wildlife and botanical) under the ESA, to include the newly added Lesser Prairie Chicken (Tympanuchus pallidicinctus) and the northern long eared bat

[183] USFWS. ECOS Environmental Conservation Online System. U.S. Federal Endangered and Threatened Species by Calendar Year. Access on January 24, 2023. https://ecos.fws.gov/ecp/report/species-listings-by-year-totals.

[184] EPA, 2022. Lean more about Threatened and Endangered Species, accessed on January 24, 2023, at https://www.epa.gov/endangered-species/learn-more-about-threatened-and-endangered-species#:~:text=There%20are%20over%201%2C300%20endangered,in%20danger%20of%20becoming%20extinct.

(Myotis septentrionalis),[185] both of which are common in oil and gas development areas. Some other listed species with the potential to inhabit oil and gas areas include:

- American Burying Beetle (*Nicrophorus americanus*);
- Gunnison Sage Grouse (*Centrocercus minimus*);
- Grey Wolf (*Canis lupus*);
- Dunes Sagebrush Lizard (*Sceloporus arenicolus*) (under USFWS Review);
- Whooping Crane (*Grus americana*).

To further protect listed species common in oil and gas areas, state and federal agencies may establish species-specific seasonal stipulations, voluntary incentive programs, and various conservation agreements with operators aimed at preserving habitats and ensuring additional species protections. For instance, in 2008 a candidate conservation agreement (CCA) was initiated for the Lesser Prairie Chicken through a collaborative effort between the USFWS, the Bureau of Land Management (BLM), and the Center of Excellence for Hazardous Materials Management (CEHMM) (see **Figure 31**).[186] This voluntary program through monetary enrollment provides conservation benefits to the Lesser Prairie Chicken while affording consistent regulatory seasonal stipulations and fewer USFWS requirements, to include removal of consultation constraints under Section 7 of the ESA.

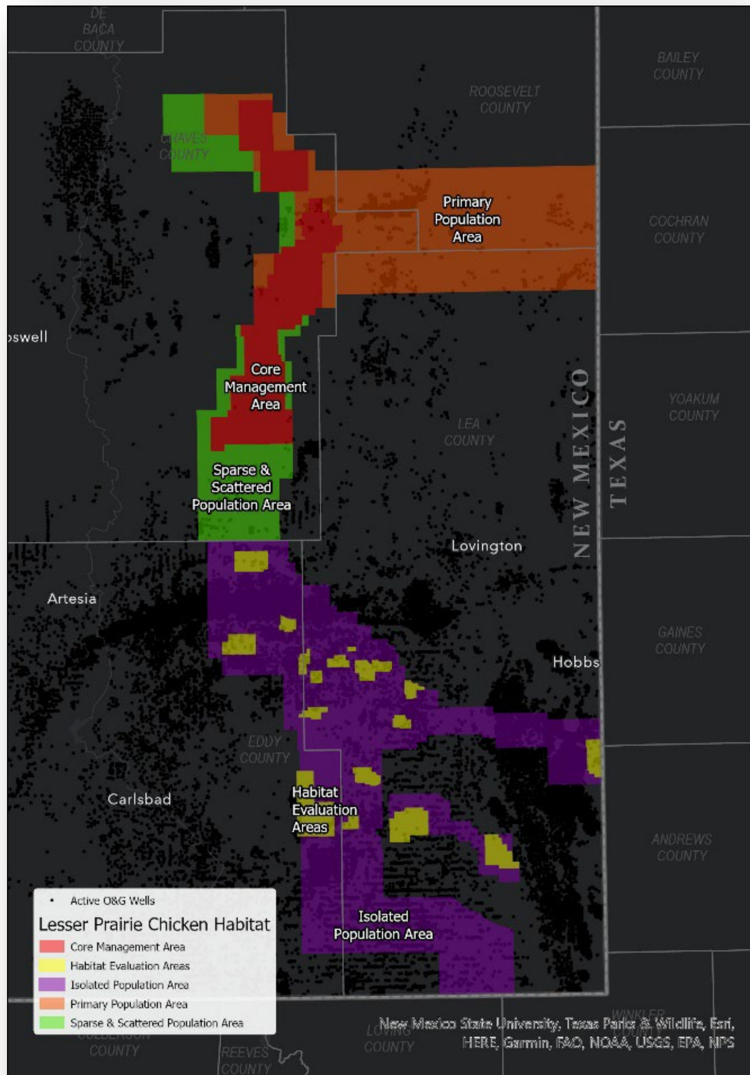

Figure 31: BLM Designated Lesser Prairie Chicken Management Areas

Through the years, independent oil and natural gas operators have demonstrated a willingness and commitment to species and habitat conservation.[187] Operators often employ voluntary best management practices (BMPs) to further protect listed species to include conducting clearance surveys prior to the commencement of surface disturbance

[185] USFWS. ECOS Environmental Conservation Online System. U.S. Federal Endangered and Threatened Species by Calendar Year. Access on January 24, 2023. https://ecos.fws.gov/ecp/report/species-listings-by-year-totals.

[186] Candidate Conservation Agreement for the Lesser Prairie Chicken (Tympanuchus pallidicinctus) and Sand Dune Lizard (Sceloporus arenicolus) in New Mexico. Developed cooperatively by U.S. Fish and Wildlife Service, U.S. Bureau of Land Management, Center of Excellence for Hazardous Materials Management, December 8, 2008.

[187] Independent Petroleum Association of America. Endangered Species. Access on January 24, 2023. https://www.ipaa.org/endangered-species/.

activities, avoiding critical habitat areas, and reducing fragmentation by combining right-of-ways, or reducing the number of wells pads via horizontal drilling. In addition, operators establish or donate to conservation programs to provide additional protective measures for species and their associated habitat through the support of public-private partnerships. For example, ConocoPhillips partnered with the Western Association of Fish and Wildlife Agencies to restore native grassland and burrowing owl (USFWS bird of conservation concern) habitat within the Permian Basin. By 2021, a total of 374 total acres were preserved within the burrowing owl project, with an additional 583 acres of contiguous rangeland refurbished or planned for restoration.[188]

4.4 Induced Seismicity

While uncommon throughout the U.S., induced seismicity has been associated with underground injection disposal and horizontal well drilling since the 1960s.[189] Only a small fraction of wells in the U.S. are linked to induced seismic events, but under the right geologic and operational conditions, any activity which alters subsurface pressure conditions near a critically stressed fault may induce seismic activity.[190] Underground injection and hydraulic fracturing operations are the activities most frequently associated with induced seismicity.

4.4.1 Injection-Induced Seismicity

Over the last decade, instances of injection-induced seismicity have been made public in news media and received significant attention from researchers, industry professionals, and state regulators. Injection-induced seismicity is caused by the increase of pore pressure at critically stressed fault surfaces. The increased pore pressure can initiate slip on a fault, leading to an earthquake. The faults at which injection-induced seismicity has been observed are primarily located in the Precambrian basement, at depths of at least 5 kilometers (km) (16,500 feet or 3.1 miles) beneath the Earth's surface; however, these faults often extend upward into overlying sedimentary formations as well, providing potential means of pore pressure communication between zones (see **Figure 32**).[191]

Evaluating and identifying injection-induced seismicity is a multidisciplinary process that requires the expertise of seismologists, geologists, reservoir engineers, hydrogeologists, geophysicists, and other professionals. It also requires access to thorough earthquake, fault, and saltwater disposal well data.

Researchers have established a seven-question screening process for determining the source of injection-induced seismicity. The process is still frequently referenced by industry experts:[192]

1. Are the events the first known earthquakes of this character in the region?
2. Is there a clear (temporal) correlation between injection and seismicity?

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[188] Texan Nature. ConocoPhillips Burrowing Owl Habitat Enhancement and Restoration. Access on January 23, 2023. https://texanbynature.org/projects/conocophillips-burrowing-owl-habitat-enhancement-and-restoration/.

[189] Raleigh, C.B. 1972. Earthquakes and Fluid Injection, American Association of Petroleum Geologists Memoir 18, Underground Waste Management and Environmental Implications.

[190] Induced earthquakes. Induced Earthquakes | U.S. Geological Survey. (n.d.). Retrieved January 9, 2023, from https://www.usgs.gov/programs/earthquake-hazards/science/induced-earthquakes

[191] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection, March 2021, 250 pages.

[192] Davis, S. D., & Frohlich, C. (1993). Did (or will) fluid injection cause earthquakes? - criteria for a rational assessment. Seismological Research Letters, 64(3-4), 207–224. https://doi.org/10.1785/gssrl.64.3-4.207

3. Are epicenters near wells (within 5 km)?
4. Do some earthquakes occur at or near injection depths?
5. If not, are there known geologic features that may channel flow to the sites of earthquakes?
6. Are changes in well pressures at well bottoms sufficient to encourage seismicity?
7. Are changes in fluid pressure at hypo-central locations sufficient to encourage seismicity?

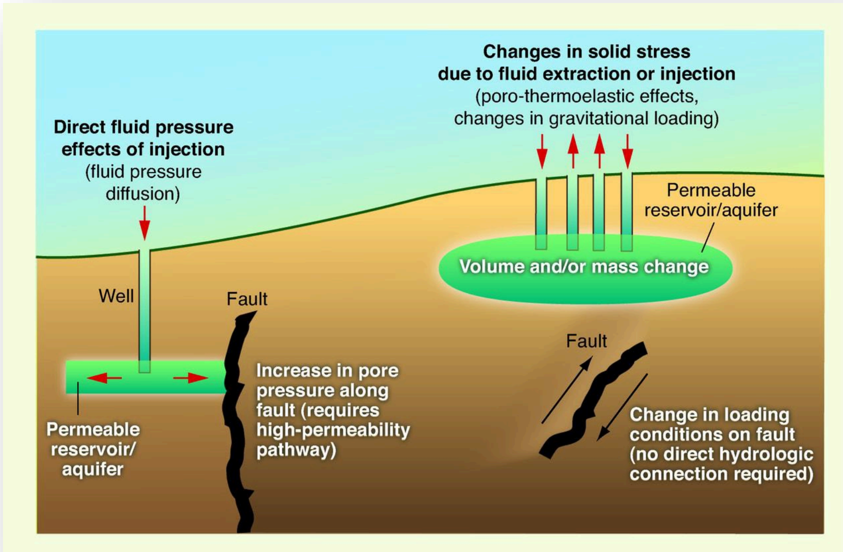

Figure 32: Physical Mechanisms of Injection-Induced Seismicity

If all seven questions are answered in the affirmative, one can reasonably conclude the earthquakes in question have been induced. Likewise, if all questions are answered in the negative, the earthquakes are unlikely to be related to injection activity. A combination of answers calls for further evaluation and analysis, but a clear answer is not always achieved.[193] With this in mind, many states have taken regulatory steps to mitigate the potential for injection-induced events to occur.

From 2008 to 2015, there was a significant increase in the number of induced seismic events in the midcontinental U.S., particularly in Oklahoma and Kansas. [194] The increase was thought to be related to the injection of wastewater into the Arbuckle Group and Ellenburger formations, which subsequently induced other events within the Precambrian basement. [195] Since 2016, the seismicity rate in Oklahoma has declined, in part to the implementation of regulatory requirements and a slowdown in oil and gas development activity (see **Figure 33**).[196] Kansas has also seen a decline in seismicity rates, but Texas continues to see an increase, often in areas lacking the deep sedimentary injection wells commonly associated with injection-induced seismicity. Researchers are investigating the increase in Texas events,

[193] ibid
[194] ibid
[195] ibid
[196] Langenbruch, C., Weingarten, M. & Zoback, M.D. Physics-based forecasting of man-made earthquake hazards in Oklahoma and Kansas. Nat Commun 9, 3946 (2018). https://doi.org/10.1038/s41467-018-06167-4

with many publications suggesting shallow injection wells, often 10,000 feet or more above the Precambrian basement, are associated with events. [197]

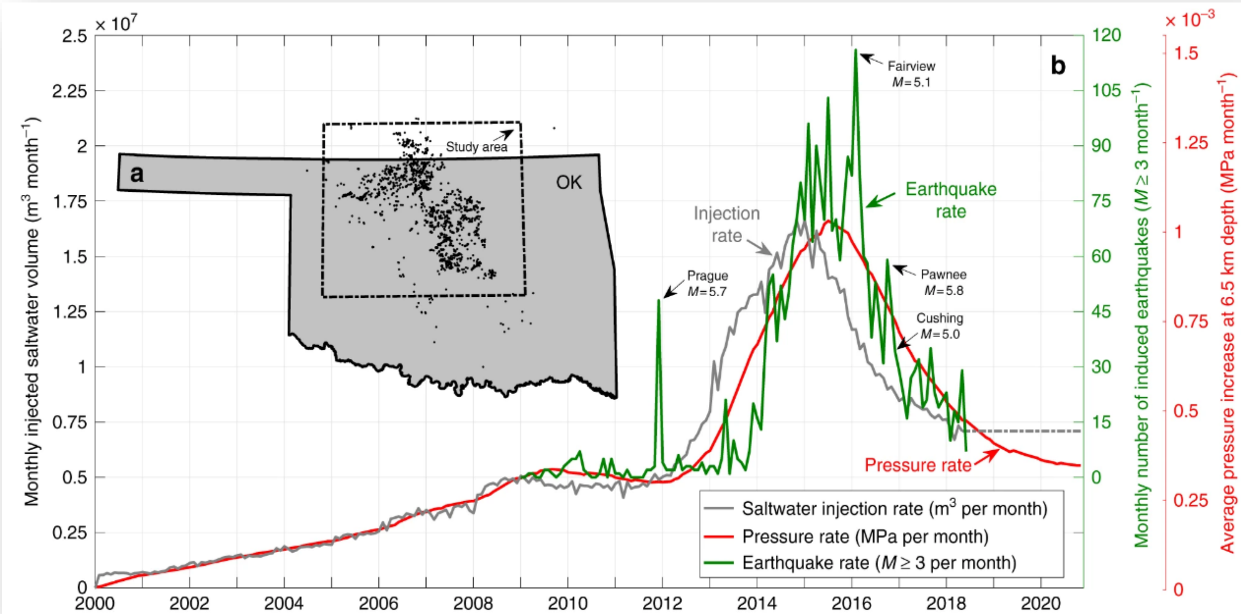

Figure 33: Significant Increase in Oklahoma Seismicity Rate from 2009 – 2015

It is important to note that seismic monitoring capabilities have increased in recent years, which means more low-magnitude earthquakes are being recorded, even if the number of earthquakes is not actually increasing. When evaluating potentially induced seismicity, it is important to consider the completeness of the seismic catalog over time. [198]

There is also a recent study and model that suggests that almost all seismicity in the Midland Basin is triggered by deep injection. There is ongoing research and studies to attempt to resolve the related issues, and to identify the primary triggering mechanisms of seismicity in other key regions, such as the Permian Basin. [199]

4.4.2 Induced Seismicity Mitigation

Seismic mitigation can occur in many forms, and many states employ one or more mitigation techniques as a part of regulatory requirements. Some commonly utilized methods of seismic mitigation are briefly described below: [200]

[197] Grigoratos, I., Savvaidis, A., & Rathje, E. (2022). Distinguishing the causal factors of induced seismicity in the Delaware Basin: Hydraulic fracturing or wastewater disposal? Seismological Research Letters, 93(5), 2640–2658. https://doi.org/10.1785/0220210320

[198] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection, March 2021, 250 pages.

[199] Lei Jin, William J. Curry, Rachel C. Lippoldt, Stefan A. Hussenoeder, Peeyush Bhargava (2023). 3D Coupled Hydro-Mechanical Modeling of Multi-Decadal Multi-Zone Saltwater Disposal in Layered and Faulted Poroelastic Rocks and Implications for Seismicity: an Example from the Midland Basin. Tectonophysics Volume 863, September 2023, 229996

[200] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection, March 2021, 250 pages.

Permanent Seismic Monitoring Networks: Such as those maintained by the USGS, are important for establishing baseline seismicity rates and seismic hazards in any given region.[201] Earthquake catalogs built from the data recorded by such networks allow regulators and operators to more easily identify when a potentially induced seismic event has occurred.[202] Identifying seismic trends also assists in locating faults, allowing for further characterization of seismic risk and hazard in an area.

Temporary Seismic Monitoring Networks: Temporary seismic networks or arrays are often used to proactively monitor new saltwater disposal wells (SWDs) in local areas where induced seismicity is an elevated risk. They may also be deployed reactively in areas experiencing abnormal seismicity patterns. Temporary seismic networks are often used in conjunction with traffic light response systems to mitigate induced seismicity and ensure SWD operations are not contributing to seismicity. **Figure 34** presents an example of a temporary seismic network layout. [203]

Fault Slip Potential Modeling: Developed and maintained by the Stanford Center for Induced and Triggered Seismicity (SCITS), this publicly available software is used to assess the potential for any given fault to experience slip when undergoing changing pressure and stress conditions due to nearby SWDs.[204]

Injection Well Siting: One of the most utilized forms of induced seismicity mitigation, injection well siting practices allow operators and regulators to qualitatively identify the risk involved with a proposed SWD location, based primarily on geological factors such as depth to Precambrian basement, presence of confining zones, proximity to faulting, and historical seismicity rates. Risk can often be minimized by siting an SWD in a location lacking in features typically associated with injection-induced seismicity.

Additional induced seismicity mitigation techniques include, but are not limited to injection rate reductions, injection pressure reductions, seismic hazard mapping, and well logging.

[201] Induced earthquakes. Induced Earthquakes | U.S. Geological Survey. (n.d.). Retrieved January 9, 2023, from https://www.usgs.gov/programs/earthquake-hazards/science/induced-earthquakes

[202] Texas seismological network earthquake catalog. (n.d.). Retrieved January 9, 2023, from https://www.beg.utexas.edu/texnet-cisr/texnet/earthquake-catalog

[203] ALL Consulting, LLC, Class II Disposal Well Seismic Monitoring and Mitigation Plan, 2023.

[204] Fault slip potential (FSP). Stanford Center for Induced and Triggered Seismicity. (n.d.). Retrieved January 9, 2023, from https://scits.stanford.edu/fault-slip-potential-fsp

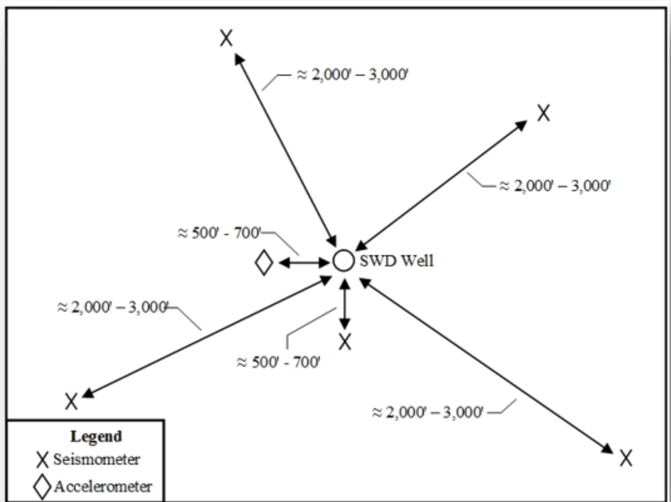

Figure 34: Example of Temporary Seismic Network Layout

4.4.3 Hydraulic Fracturing-Induced Seismicity

Hydraulic fracturing-induced seismicity typically results in smaller magnitude seismic events than injection-induced seismicity, and the seismic events from hydraulic fracturing are rarely felt.[205] The largest hydraulic fracturing-related seismic event recorded in the U.S. was a magnitude (M) 3.5 event that occurred on May 1, 2018, in the Eagle Ford play of Texas.[206]

During hydraulic fracturing, fluid is injected at a higher rate for shorter periods than during routine injection disposal. The fracturing fluid is pumped into the formation at high rates and pressures purposely to exceed the formation fracture gradient, creating fractures and increasing permeability. Hydraulic fracturing always results in micro seismic events. These events can be recorded to characterize and image the ongoing operations.

Individual stages during a fracture treatment typically only last a matter of hours and are dispersed within a limited spatial area. Hydraulic fracturing-induced seismicity can be identified by clear temporal and spatial correlations between the hydraulic fracturing operations and the resulting seismic events. Hydraulic fracturing operations involve significant data collection, which allows operators to better characterize the subsurface conditions and identify potentially induced seismic events.[207] Several states have implemented regulatory policies with the goal of limiting the magnitudes of seismic events due to hydraulic fracturing operations.

[205] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection, March 2021, 250 pages.

[206] Fasola, S. L., Brudzinski, M. R., Skoumal, R. J., Langenkamp, T., Currie, B. S., & Smart, K. J. (2019). Hydraulic fracture injection strategy influences the probability of earthquakes in the eagle ford shale play of south Texas. Geophysical Research Letters, 46(22), 12958–12967. https://doi.org/10.1029/2019gl085167

[207] Ground Water Protection Council and Interstate Oil and Gas Compact Commission. Potential Induced Seismicity Guide: A Resource of Technical and Regulatory Considerations Associated with Fluid Injection, March 2021, 250 pages.

5 Closing Thoughts

Our original publication "*Modern Shale Gas Development in the United States*" was published in 2009 following the rapid expansion of horizontal drilling and shale gas development. Since that time, the pace of change in the unconventional development arena has been brisk seeing many changes in the technical, regulatory, and operational best practices disciplines. This updated primer seeks to inform stakeholders on these changes, give a current assessment of shale gas development, and highlight the water protection efforts put in place by state regulatory agencies.