Daniel J. Soeder

Fracking and the Environment

A scientific assessment of the environmental risks from hydraulic fracturing and fossil fuels

Springer

Fracking and the Environment

Daniel J. Soeder

Fracking and the Environment

A Scientific Assessment of the Environmental Risks from Hydraulic Fracturing and Fossil Fuels

Springer

Daniel J. Soeder
South Dakota School of Mines & Technology
Rapid City, SD, USA

ISBN 978-3-030-59120-5 ISBN 978-3-030-59121-2 (eBook)
https://doi.org/10.1007/978-3-030-59121-2

© Springer Nature Switzerland AG 2021
This work is subject to copyright. All rights are reserved by the Publisher, whether the whole or part of the material is concerned, specifically the rights of translation, reprinting, reuse of illustrations, recitation, broadcasting, reproduction on microfilms or in any other physical way, and transmission or information storage and retrieval, electronic adaptation, computer software, or by similar or dissimilar methodology now known or hereafter developed.
The use of general descriptive names, registered names, trademarks, service marks, etc. in this publication does not imply, even in the absence of a specific statement, that such names are exempt from the relevant protective laws and regulations and therefore free for general use.
The publisher, the authors, and the editors are safe to assume that the advice and information in this book are believed to be true and accurate at the date of publication. Neither the publisher nor the authors or the editors give a warranty, expressed or implied, with respect to the material contained herein or for any errors or omissions that may have been made. The publisher remains neutral with regard to jurisdictional claims in published maps and institutional affiliations.

This Springer imprint is published by the registered company Springer Nature Switzerland AG
The registered company address is: Gewerbestrasse 11, 6330 Cham, Switzerland

Dedicated to the memory of James Paul Soeder (1956–2008), brother, friend, hiking companion, and always a tireless advocate for the environment.

Preface

Many people by now have heard the term "fracking," and most know that it is related to the production of petroleum and natural gas. There are numerous concerns about the impacts fracking may have on the environment, and quite a few environmentalists and political leaders are calling for it to be banned altogether. Movies like "Gasland," reinforced by viral posts on social media, have linked fracking in popular culture to air pollution, damage to the environment, contamination of surface water and groundwater, and risk to human health. Other films like "FrackNation" claim that environmental activists and the media have suppressed any and all facts that show the process does not harm the environment.

So who is correct? Is it really that bad or not? There are a lot of complexities and nuances in any detailed response to that question, but the short and unsatisfying answer is that we don't know.

What we do know is that the use of fracking has substantially increased the production of domestic oil and gas (O&G) in the United States, essentially doubling it over the past decade. This was actually a long-term American national goal following the OPEC oil embargo and the resulting "energy crisis" in the 1970s. Abundant production of shale gas and tight oil through the use of fracking has freed the United States from the need to import petroleum to meet energy demands and greatly increased the abundance of natural gas. America is less vulnerable to threats from the politics of oil, at least for now.

The politics have not gone away however, but have merely changed strategy. Fracking reversed the role of the United States in global energy politics from importer to exporter, much to the dismay of established petroleum exporting countries like Saudi Arabia and Russia. These countries have in fact made it their goal to shut down US tight oil and shale gas production by any economic means possible, but primarily through price wars. The production of O&G from resources that require hydraulic fracturing is more expensive than conventional O&G production. Thus, the "break-even" cost for energy resources produced through fracking is generally higher than for those that are not. As long as worldwide oil and gas prices remained high, this didn't matter, but once they dropped below the threshold for fracking while remaining profitable for conventional production, the fracked resources suffered.

American producers fought back with increased efficiency to lower production costs, but the bottom line is that the break-even point for Saudi conventional oil production is about half the cost of Bakken Shale tight oil production in North Dakota. This price battle has been raging since about 2015, with overproduction causing a glut in the world's oil supply along with depressed prices. This was before the coronavirus pandemic that began in early 2020 sharply reduced oil demand, first in China, then Europe, and finally worldwide as people stopped traveling. The combination of oversupply and lower demand caused petroleum prices to fall to historic lows (including briefly to zero). As a result, many American O&G production companies went deeply into debt and more than a few US shale production companies have gone into bankruptcy. Financial institutions are questioning the wisdom of backing the development of shale gas and tight oil, and many are refusing to do so. One can't help but wonder if the whole North American shale gas–tight oil energy economy is built on a house of cards.

Political and economic issues aside, the greatest concern related to fracking is arguably the potential environmental risks. These are not at all clear. Estimates of the environmental impacts from the technology literally range from severe to none. Scientific investigations into the potential risks of fracking began more than a decade ago, but in the past 5 years the number of papers published on the geophysics, geochemistry, geology, hydrology, atmospheric chemistry, biology, ecosystem, and human health effects of fracking has grown exponentially. There are now hundreds, possibly thousands of peer-reviewed, published documents that attempt to define the risks and benefits of fracking, including several books (e.g., Wilbur 2012; Sernovitz 2016; Schug and Hildenbrand 2017; Raimi 2018).

Rather than clarify things, this massive body of publications has muddied the waters. One doesn't have to wade too deeply into the literature to determine that fracking is far from a black and white, cut and dried issue. Many scientists approached these investigations with the expectation that links between fracking and devastating environmental impacts would be glaringly obvious, but found instead that the details are far more nuanced and complex. Review studies ended up producing thousand-page documents. Compilations of existing literature turned up hundreds of articles. Different research teams often reached contradictory conclusions, sometimes with almost identical data sets. The sheer volume of literature combined with the confusing results has made it increasingly difficult for average, concerned citizens (and even many regulators and research scientists) to sort out the risks and benefits of fracking.

With a few exceptions described in later chapters of this book, no studies have been able to definitively link fracking with significant environmental degradation. This does not mean to suggest that there are no environmental impacts from O&G development in general, because indeed there are many. However, fracking is only one aspect of the hydrocarbon production process. When talking about specific impacts to the environment from the fracking technology itself, these are minimal. Unfortunately, some environmentalists have conflated fracking into a catch-all term for all O&G production, covering everything from bulldozers knocking down trees to offshore oil spills, and of course there can be significant environmental impacts from these activities. But they are not fracking. The incorrect use of this term by environmentalists demonstrates a significant misunderstanding of how fossil fuels are produced and results in the O&G industry not taking them seriously. The two sides end up talking past each other using words that have completely different meanings.

Most of the published environmental studies have concluded that more data are needed to find definitive answers, but data are hard to come by. The O&G industry has typically not been willing to help researchers discover environmental problems that could result in costly liabilities, no matter how “interesting” these may be scientifically. Even many landowners have refused to cooperate for the same reason. Without access to well sites, production data, and information about drilling activities and completion dates, potential environmental contaminants related to fracking can’t be monitored, and much of this research has been starved of data.

Nevertheless, the lack of industry cooperation has not stopped researchers from delving into a wide range of fracking investigations, which resulted in a huge explosion of publications starting around 2010 (Costa et al. 2017). The body of available literature reflects a broad variety of different perspectives, and the sources provided in the references of this book are recommended for additional reading. Every effort was made to include the most relevant documents, but given the volume of publications, it is certainly possible that many critical papers were left out. This was by no means an intentional omission, but simply an effort by the author to keep from drowning in literature. If there are important papers that are not included in the citations, please let me know. I will add them to later editions of this book.

Some people think it is impossible for fossil energy to co-exist with environmental protection. This is not true; the science and engineering are definitely available to obtain and use energy from a variety of sources, including fossil fuels, with minimal environmental impacts. However, protecting the environment is usually not the cheapest option for extracting or using energy. People want the least expensive energy they can get, and fossil fuel is cheap. Few individuals would willingly request a higher electric bill for renewable electricity or seek to pay twice as much for zero-emissions cars just because these are better for the environment. Yes, some concerned people do install solar panels and buy electric vehicles, but they are exceptions far outnumbered by those connected to the electric grid and driving large pickup trucks. But more expensive fossil fuels must be in our future if we want to move away from fossil energy. When the cost of protecting the environment is included in the price of fossil fuels, they become far more expensive. Pricier fossil fuels are not necessarily bad; for one thing it would make renewables more cost-competitive and would also encourage energy conservation.

People often ask where I stand personally on the issue of fracking. In short, I stand with the data, the facts, and the documented findings. I support both the environment and the energy industry. At the end of the day, our society needs a clean and livable environment, but our technological civilization also requires energy to run.

There are right ways and wrong ways to obtain energy while protecting the environment. So far, we have been doing it mostly wrong.

My geology career started in the wake of the 1970s "energy crisis," and I understand the need for domestic shale gas and tight oil development. These resources could not be recovered economically without fracking. My research on shale gas during the first decade of my career was focused on helping to solve the problems of recovering hydrocarbons from these rocks (e.g., Soeder 1988). The eventual development of shale gas and tight oil in the United States was a success story that ended American dependence on imported oil (Soeder and Borglum 2019).

I spent two decades investigating water resources as a hydrologist for the U.S. Geological Survey (USGS), and I became acutely aware of just how vulnerable both surface water bodies and groundwater are to the careless acts of humans. Protecting the environment had always been important to me, but tracking the migration of chlorinated solvents and other assorted nasties in groundwater brought it into a much sharper focus. I first began to look at the potential effects of fracking on water resources in 2008 while living in Maryland and learning that gas production from the Marcellus Shale had taken off next door in Pennsylvania (Soeder and Kappel 2009). My research efforts since then have been centered largely on energy and the environment.

During my eight years with the U.S. Department of Energy (DOE), I was involved in a multi-agency government assessment of the environmental risks of shale gas and tight oil development (Soeder and Kent 2018). The Environmental Protection Agency (EPA), DOE, and the USGS were the lead agencies on this assessment. The Department of Health and Human Services (HHS) was also brought in to provide public health risk assessments, and the National Science Foundation (NSF) was included so the government agencies were aware of and not duplicating NSF-supported research at universities. The multi-agency assessment ran from 2012 to 2017 and produced several substantial reports (Multiagency 2014; USDOE 2015).

The federal multi-agency investigation identified seven areas of concern with fracking and shale energy development. These were (1) determining new locations of future resource development that might be affected by fracking, (2) water availability, given the large volumes needed for fracking, (3) effects of frack fluid chemicals and produced fluids on surface water and groundwater quality, (4) air quality impacts from well installation practices and the production of hydrocarbons, (5) induced seismicity from both fracking and the underground disposal of produced water, (6) both terrestrial and aquatic ecosystem impacts, and (7) human health effects from exposure to fracking and shale gas production (USDOE 2015).

For years, the issue of fracking has been controversial, surrounded by sensationalism, hype, denial, disbelief, hand-wringing, and outright fiction. Because government agencies by and large do not embrace controversy, my first book on the subject (Soeder 2017) required 4 years, a dozen reviews, and eight revisions to receive approval. It was not until after I had left government service in 2017 to direct a university research program that I started working on the book you are currently reading. For those concerned about it, I have not received funding from either industry or environmental groups while assembling this manuscript.

No one person can know everything and I welcome any additional rigorous scientific information that may add to or even contradict what I have presented in this book. This is how science is supposed to work. Scientists who are unwilling to revise conclusions based on new data are usually not very good scientists.

This book describes what fracking is and is not, along with how and why it was developed against the historical backdrop of oil and gas production in the United States. It then lays out what we know and do not know about the risks of fracking to air, water, landscapes, ecosystems, and human health. The final chapters delve into the broader issues of fossil fuels and climate change, greener fracking, balancing energy and the environment, and options for humanity's potential energy future. The book uses peer-reviewed studies, published technical literature, and referenced data to tell what I hope is an interesting story. The book itself has also been peer-reviewed. I have attempted to keep it objective, unbiased, and centered on the facts. If you were expecting sensationalism and thrilling suspense with evil bad guys and heroic good guys, I am sorry to disappoint. For that kind of drama, I suggest going to see a movie.

Rapid, SD, USA Daniel J. Soeder

References

Costa, D., Jesus, J., Branco, D., Danko, A., & Fiuza, A. (2017). Extensive review of shale gas environmental impacts from scientific literature (2010–2015). *Environmental Science & Pollution Research*. https://doi.org/10.1007/s11356-017-8970-0. 16 p, published online April 2017.

Multiagency: U.S. Department of Energy, U.S. Department of the Interior, and the U.S. Environmental Protection Agency. (2014). *Federal Multiagency Collaboration on unconventional oil and gas research: A strategy for Research and Development*. Report to the Executive Office of the President, July 18, 2014, Washington, DC, 18 p.

Raimi, D. (2018). *The fracking debate: The risks, benefits, and uncertainties of the shale revolution*. New York: Columbia University Press. 350 p.

Schug, K. A., & Hildenbrand, Z. L. (2017). *Advances in chemical pollution, environmental management and protection: Environmental issues concerning hydraulic fracturing*. Cambridge, MA: Academic. 405 p.

Sernovitz, G. (2016). *The green and the black: The complete story of the shale revolution, the fight over fracking, and the future of energy* (289 p). New York: St. Martin's Press.

Soeder, D. J. (1988). Porosity and permeability of eastern Devonian gas shale. *SPE Formation Evaluation, 3*(1), 116–124. https://doi.org/10.2118/15213-PA.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

Soeder, D. J., & Kappel, W. M. (2009). *Water resources and natural gas production from the Marcellus shale*. U.S. Geological Survey, Fact Sheet 2009–3032, 6 p.

Soeder, D. J., & Kent, D. B. (2018). When oil and water mix: Understanding the environmental impacts of shale development. *GSA Today, 28*(9), 4–10.

Wilbur, T. (2012). *Under the surface: Fracking, fortunes, and the fate of the Marcellus shale*. Ithaca, NY: Cornell University Press. 329 p.

Acknowledgments

I thank the Energy Resources Initiative at the South Dakota School of Mines & Technology for partial financial support during the preparation of this manuscript. Ron Doering and Aaron Schiller at Springer Nature made the process easy and their enthusiasm kept it going. Numerous colleagues at the South Dakota School of Mines & Technology, West Virginia University, the U.S. Geological Survey, Geological Survey of Canada, and the U.S. Department of Energy provided valuable feedback and insights. Dr. Donna Vorhees of the Health Effects Institute in Boston supplied comprehensive information on the status of various ongoing health and environmental studies. Conversations with environmentalists, O&G industry personnel, state regulators, and university researchers provided insights into the issues, concerns, and knowledge gaps. Interactions with graduate students and professors in the United States and Canada helped shape the narrative and focus the discussions. I also thank the reviewers: Seth Pelepko of the Pennsylvania Department of Environmental Protection, Nate Warner at Penn State, and one anonymous reviewer. Their comments and suggestions helped improve the manuscript.

I also thank my family for inspiration, including my late brother Jim, an ardent environmentalist and outdoor adventurer to whom this book is dedicated, my other brothers and sister, my wife, my children, and my grandson, who will be inheriting this planet someday. There is a Native American proverb that states, “We don’t inherit the Earth from our ancestors; we borrow it from our children.” Wise words, indeed.

Contents

About the Author

Daniel J. Soeder spent 25 years with the federal government as a research scientist and geologist. His work with the U.S. Geological Survey (USGS) included coordinating hydrologic and geologic fieldwork on the Yucca Mountain Project in Nevada and researching coastal hydrology, wetlands, water supply, and water contamination in the Mid-Atlantic. He chaired the Scientific and Technical Advisory Committee (STAC) for the Delaware Estuary Program for 3 years. His experience at the U.S. Department of Energy (DOE) National Energy Technology Laboratory in Morgantown, West Virginia, included energy and environmental research on gas shale and other unconventional fossil energy resources. He also spent a decade carrying out studies on the geology of unconventional natural gas resources at the Institute of Gas Technology (now GTI) in Chicago. He was director of the Energy Resources Initiative at the South Dakota School of Mines & Technology in Rapid City, South Dakota, from 2017 to 2020, and holds an adjunct appointment at West Virginia University. He has authored multiple reports, scientific papers, and two previous books on shale, and he has also investigated and written about the impacts of shale gas development on the environment. Raised in Cleveland, Ohio, he received a B.S. degree in geology from Cleveland State University in 1976 and an M.S. degree in geology from Bowling Green State University (Ohio) in 1978. He has three children and a grandchild who deserve a better world.

List of Figures

Chapter 1
Introduction

Hydraulic fracturing to recover oil and gas is contentious and controversial in the United States and around the world. Strident disagreements, pitched arguments, strong vitriol, and deep distrust are hallmarks of the fracking issue, muddling the facts. Civic meetings on fracking are often far from civil, devolving into contentious affairs with dramatic statements, raw emotions, and raised voices. It makes for wonderful television. The news media dutifully record all this drama and forward it to the broader American public, who can only conclude that we are facing either an environmental calamity if we allow fracking or an economic collapse if we don't.

Both sides are wrong. Fracking is less of a risk than opponents believe, but neither is it as safe as proponents claim. Both groups need to step back and take a deep breath.

Opposition to fossil fuels and especially fracking has become a de-facto requirement for membership in many environmental organizations these days, and arguments to the contrary are not welcome. Some environmentalists have flat-out stated that they don't care what the facts show, they are against fracking and will remain opposed to it no matter what. A number of Hollywood celebrities, TV news personalities, prominent physicians, and famous attorneys have gone on the record as being opposed to fracking. Without ever having done the math, various politicians have promised to ban the practice, and lead the nation to a utopian future of stable climates with abundant, inexpensive, renewable energy. Most of these people know almost nothing technical about fracking (or renewable energy, for that matter). Just as scientists shouldn't act in movies, and engineers shouldn't defend suspects in a court of law, actors and attorneys have no business commenting on technical issues they don't understand. Some sensationalized warnings from celebrity activists about supposed fracking "risks" were bogus, and only served to divert attention away from the real risks.

An entire mythology (and industry) has been constructed around the supposed dangers of fracking from the "Gasland" movies and related literature. Touchstones include flaming kitchen faucets (Fig. 1.1), exploded well vaults, and jugs of

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_1

Fig. 1.1 A flaming kitchen faucet caused by natural gas entering a domestic water supply well in Pennsylvania. Images like this have become linked to environmental concerns about fracking. (Photo copyright Getty Images; used under license)

sludge-like well water. Dark warnings about dangerous "fracked gas" moving through pipelines and entering people's homes like an evil spirit are promulgated by some environmentalists, even though fracked gas and non-fracked gas are essentially the same thing and can't be told apart in a pipeline. The issue of fracking is often intertwined with other environmental concerns about fossil fuels, such as sustainability, air and water pollution, and elevated levels of greenhouse gas (GHG) in the atmosphere. Most GHG comes from burning coal, and has nothing whatsoever to do with fracking (U.S. Department of Energy 2012).

Interestingly, most if not all of these "flaming faucet" photographs like Fig. 1.1 are burning methane gas created by methanogenic bacteria living in the aquifer. The presence of methane in the groundwater supply almost never has anything to do with nearby fracking, but it has become indelibly linked to it in the minds of many through these images. There have been several studies (described in later chapters) in northeastern Pennsylvania that found dissolved methane to be nearly ubiquitous in groundwater. A number of lawsuits were unable to link shale gas development to the presence of methane in shallow aquifers. In at least one case, attorneys found that the occurrence of methane in the water well pre-dated the arrival of the shale gas drill rig by at least several years.

On the other side of the issue are the proponents of fracking, primarily the oil and gas (O&G) companies themselves. Industry people contend fracking is a mature technology that is well-understood, safe, and has been in use since 1947 to recover hydrocarbons. In the opinion of many, opposition to fracking is coming from non-technical outsiders who do not understand the process. Since the O&G industry generally can't be bothered to actually explain the process in terms that ordinary people can understand, this adds to the confusion. Their reluctance to discuss operational details is often interpreted as being elitist, secretive, and unresponsive. A few companies and industry groups have published brochures and webpages attempting to explain fracking, but many opponents see this information as "tainted" or biased because it comes from the industry. Ironically, the people who really understand fracking technology are almost all employed in the O&G industry, so that is where the expertise can be found.

The industry response to questions about fracking is commonly along the lines of "We know what we are doing; trust us." This falls flat on the public after incidents like the Exxon Valdez and Deepwater Horizon, which clearly demonstrated that although industry may know what they are doing for the most part, accidents still happen with disastrous consequences. The credibility of fracking proponents is further strained by vocal supporters with obvious conflicts of interest, such as climate-change deniers, politicians funded by big oil donations, and wealthy O&G investors. The lack of trust between the American public and big oil is a longstanding issue. The only industry Americans consider less trustworthy is big tobacco (Theodori 2008).

So how does one sort all this out? The only legitimate, defensible way to assess the risk of fracking is through rigorous science, accurate data, careful review, and unbiased conclusions. A two-state assessment by Kell (2011) found that gas wells have a rate of "reportable incidents" or environmental violations on the order of 0.5–0.1% or less of the total wells drilled. This ranges from one well out of 200 to one well out of 1000 and includes both unfracked and fracked wells. The majority of these "reportable" incidents are minor, such as incorrect signage or small spills. Significant violations are rare, but they do happen (Brantley et al. 2014). Wellbore integrity problems were found to be statistically more frequent in "fracked" versus "unfracked" wells (Ingraffea et al. 2014), although the incident rate is similar in both types (Kell 2011).

Even a risk of one in 1000 is still significant. If aircraft had this risk of crashing, there would be two crashes per day at Chicago's O'Hare International airport, which operates around 2000 daily flights. The actual commercial aviation risk in 2019 was about one fatal accident per 5.5 million flights (Source: https://to70.com/to70s-civil-aviation-safety-review-2019/; accessed 1/1/19). The aircraft example serves to introduce another aspect of risk. Risk is defined not only by the probability of an event, but also by the consequences of the event. Risks that have severe consequences must be reduced to a very low probability of occurrence. Commercial aviation has spent huge amounts of time and money to reduce the probability of aircraft accidents because the consequences are horrendous.

Does fracking have any positive benefits to offset potential risks? According to data from the U.S. Energy Information Administration (USEIA), the United States is now the top producer of natural gas in the world, exceeding Russian production in 2009. The U.S. is also the number one producer of petroleum in the world, surpassing Saudi Arabia in 2013 (Fig. 1.2). These huge volumes of hydrocarbons are being recovered by fracking into previously untapped resources.

In a little more than a decade, the U.S. has gone from preparing to import liquefied natural gas (LNG) to becoming an LNG exporter. Petroleum imports have

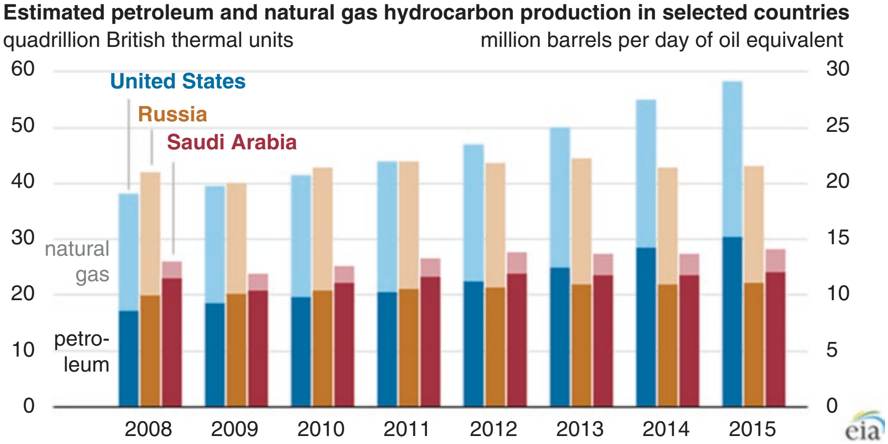


Fig. 1.2 Annual production of natural gas and petroleum in the United States compared to Russia and Saudi Arabia. (Source: Reproduced from U.S. Energy Information Administration (USEIA) webpage, dated May 21, 2018 (https://www.eia.gov/todayinenergy/detail.php?id=36292))

dropped sharply, and the U.S. now exports more oil than it imports. No matter how one feels about fracking itself, there is no denying that it has made a major impact on the energy economy of the United States, and indeed the world.

The O&G business often views environmentalists as impediments to progress, wanting to endlessly study everything, constantly finding problems, needlessly slowing down production, reducing profits, and always ready to impose additional, burdensome regulations on a long-suffering (in their eyes) industry. The typical attitude in the O&G industry is to address problems as they come up, but not to go out looking for them. The goal is to charge ahead, and leave well enough alone if at all possible.

As such, the O&G industry has been remarkably uncooperative about helping independent researchers gather data that would better quantify the environmental impacts of fracking. Much of what has been done to date (e.g. Kell 2011; Ingraffea et al. 2014) has relied on state records of environmental incidents and well permitting reports. The United States government has no authority to compel industry to cooperate on such a study, and neither do the states outside of the permitting process. However, the critical data needed to address these issues can only be obtained with access to drill rigs, frack jobs, production sites, and long-term air and groundwater monitoring. More than a few researchers have asked (i.e. Soeder 2015) if industry is so confident that there are no environmental problems with fracking, why do they restrict access to sites and data?

1.1 Concepts of Risk

Environmentalists point to modern ghost towns like Love Canal, NY (poisoned by toxic chemical waste), Times Beach, MO (poisoned by dioxin), and Picher, OK (poisoned by lead and zinc mining) as examples where industry and government indifference persisted for years before any action was taken. Similar indifference by the O&G industry toward collecting data about the possible environmental risks of fracking could lead to another potential disaster in the future. A lack of data is not the same thing as a lack of evidence (Werner et al. 2015). This is often stated as “absence of evidence is not evidence of absence.” Some issues may take a long time to become apparent, such as the links between cigarette smoking and lung cancer.

The “calculation” of risk is all about probability and statistics. Probability predicts a range of outcomes, but not a specific result. However, the higher probability outcomes are more likely than something that is a long shot. People who perform risk assessments and contingency planning look at the full range of outcomes, but focus on the most likely.

The “perception” of risk is a different story. Instead of statistics, it is based on feelings, which can be manipulated. The casino operators in Las Vegas understand this well. Although the mathematical probability of winning any single roll of the dice or hand of cards is slanted heavily in favor of the house, the gaming industry has persuaded the public to perceive that the risk of losing money is low. A percentage of players do indeed win, but if one tallies up the outcome of every single bet placed in a day, the majority of the winnings go to the casino itself. Nevertheless, the casino operators manipulate risk perceptions by enshrining the people who do win with photographs in a casino “hall of fame” to convince everyone else that their picture could easily be up on that wall also. This gives visitors to Las Vegas a feeling that they have a really good chance to win big money, a term sometimes referred to as delusional optimism. It only requires a moment of reflection to realize that the hotels don’t pay for extravagant shows, free drinks, nice restaurants, and discount rooms by giving away money in the casinos. Despite this logic, people keep going there on vacation, losing a fortune, and returning with fresh optimism the following year. If the public truly understood probability and statistics, Las Vegas would have gone under long ago.

The misunderstanding between perceived risk and actual risk sometimes drives actions that might be considered irrational. For example, there are people terrified of flying who will drive to the airport without wearing a seatbelt. Given the statistics for fatal accidents per miles traveled, the probability of an accident on the drive to airport is far higher than the risk on a commercial flight. Yet the flight is perceived by some as being far more dangerous based on their feelings. Everyone has their own ideas about what is considered an acceptable risk and what is not, but basing this on feelings rather than probability may result in skewed decisions that might actually expose someone to much greater harm.

A number of the perceived risks of fracking have become imbedded in the public consciousness due to the lack of data on actual risks, and the subsequent promotion of these supposed dangers in books, movies, and news media. One of the most prevalent of the perceived risks is that fracking will lead to the widespread contamination of groundwater, including the shallow aquifers that supply drinking water for many domestic wells. This concern led the U.S. Congress to ask the Environmental Protection Agency (EPA) to investigate in 2010.

After an exhaustive five-year study of the potential risks to underground sources of drinking water (the official EPA name for shallow groundwater), the EPA published a massive report of their findings (USEPA 2016). The study concluded that while fracking may cause local pollution and environmental impacts, the data do not show that fracking results in widespread, systemic groundwater contamination. This was boldly stated in the draft version of the report, but the EPA scientific advisory board responded to environmentalist objections and commented that the lack of available data could not support such a firm conclusion. It was much more subdued (but still there) in the final report.

Many other independent research papers on the environmental risks from fracking at both large-scale and site-specific levels also have been published in the last decade. A representative but by no means exhaustive list includes: Hayes (2009), Engle et al. (2011), Osborn et al. (2011), Fisher and Warpinski (2012), Rowan and Kraemer (2012), Warner et al. (2012), Gassiat et al. (2013), Jackson et al. (2013), Litovitz et al. (2013), Vidic et al. (2013), Bloomdahl et al. (2014), Brantley et al. (2014), Cluff et al. (2014), Davies et al. (2014), Esswein et al. (2014), Hammack et al. (2014), Hladik et al. (2014), Ingraffea et al. (2014), Moore et al. (2014), Orem et al. (2014), Pétron et al. (2014), Soeder et al. (2014), Vengosh et al. (2014), Ziemkiewicz et al. (2014), Birdsell et al. (2015), Drollette et al. (2015), Llewellyn et al. (2015), McMahon et al. (2015), Phan et al. (2015), Reagan et al. (2015), Rodriguez and Soeder (2015), Siegel et al. (2015), Townsend-Small et al. (2015), Werner et al. (2015), Akob et al. (2016), Allen (2016), Eisele et al. (2016), Kahrilas et al. (2016), Lefebvre (2016), McMahon et al. (2016), Renock et al. (2016), Butkovskyi et al. (2017), Cahill et al. (2017), Cozzarelli et al. (2017), Goetz et al. (2017), Costa et al. (2017), Krupnick and Echarte (2017), McMahon et al. (2017), Meng (2017), Orem et al. (2017), Yan et al. (2017), Banan and Gernand (2018), Bari and Kindzierski (2018), Barth-Naftilan et al. (2018), Bean et al. (2018), Benedict et al. (2018), Brantley et al. (2018), Engelder and Zevenbergen (2018), Entrekin et al. (2018), Omara et al. (2018), Pekney et al. (2018), Soeder and Kent (2018), Williams et al. (2018), Woda et al. (2018), Allshouse et al. (2019), Forde et al. (2019), McMahon et al. (2019), Thomas et al. (2019) and Mumford et al. (2020).

There are literally hundreds of these studies, and the uptick in publications over the last five years is no fluke – the number of ongoing investigations has increased significantly in recent years. The most comprehensive list of fracking-related environmental research has been compiled by the Health Effects Institute in Boston and is available on their website. Remarkably, none of the studies so far have produced data that contradict the findings of the EPA assessment.

Many environmentalists are unhappy with the inability of researchers to document fracking as a cause of widespread environmental devastation because it challenges cherished beliefs. Beliefs are not facts, however. It is important to understand that the motivation for most of the researchers who performed these studies was a sincere belief that fracking was causing irreparable damage to the environment. The authors are largely water, ecosystem, biological, and environmental researchers at universities, government agencies, or consulting firms, not shills for the O&G industry. Most of the studies were funded by the National Science Foundation, the EPA, the USGS, the U.S. Department of Energy, state agencies, and private foundations. Very few received industry funding or cooperation. The studies were designed to document air pollution, water contamination, ecosystem destruction, and public health impacts from fracking. The data showed that these things do happen on a case-by-case basis, but the impacts are neither systemic nor widespread. In fact, the impacts of fracking were hard to distinguish from the impacts of conventional O&G wells. The studies were further complicated by the presence of many existing contaminants in the environment that are unrelated to O&G.

The production of O&G by fracking appears to be no better or worse for the environment than production from conventional wells. The designation of "fracking" as its own category of risk is nothing more than an artificial construct. In reality, it is just another type of completion technique used on O&G wells, and while there are overall risks to the environment from the production and use of fossil fuels, treating fracking as a special risk is a perception, not reality.

With few exceptions, the people who have done the environmental studies related to fracking are good scientists who based their conclusions on the data. This is exactly how the scientific method is supposed to work. Investigations of contentious issues like fracking, climate change, genetic modifications, vaccine effectiveness, and others sometimes reach conclusions that don't please everyone, but the response is always the same: anyone with data that can prove the prevailing conclusions to be wrong is enthusiastically invited to publish it in a peer-reviewed journal. The goal of science is to seek the truth. Wrong paths are often taken during the quest, but mistakes also provide learning opportunities. There are no faith-based components in science, nor any theological commandments, except perhaps "thou shalt honor the data." The most solid, long-standing scientific principle can be overturned in a New York minute if new data become available. Einstein toppled Newton. Someday, someone will topple Einstein. And so it goes.

Science denial has become a significant problem in the U.S. and indeed around the world. Ideas that the moon landing was faked, the Earth is flat, jet aircraft spew trails of hazardous chemicals in the atmosphere, and vaccines are dangerous may seem relatively harmless, but they are not. Measles was essentially eliminated as a disease, but thanks to anti-vaxxers, it is making a comeback. Rock samples returned from the moon look very different under a microscope from Earth rocks, and this cannot be faked. There is no evidence showing jet aircraft exhaust consists of anything other than carbon dioxide and water vapor.

Millions of people believe the Earth is flat, despite the fact that no one has ever provided a single shred of evidence like pictures of the edge, images of a flat disk from space, alternate explanations for the changes in sun elevation at different latitudes, or why every other large body in the solar system, from the moon to the sun appears to be a round sphere. This willingness to believe in something without evidence is called religion, not science. Pop culture and social media tend to treat all viewpoints as valid, but considering an idea like the flat Earth to be a valid alternative viewpoint when it is based on zero evidence only ends up overshadowing many of the real scientific problems in the world. An anti-science response to issues like climate change, plastic in the oceans, loss of tropical rainforest, spread of contagious disease, the extinction of species, and yes, even fracking with policies based on beliefs rather than data can have serious consequences. At best, the very existence of the problem is denied, and nothing gets done. At worst, governments and regulators may focus on fixing the wrong thing and people die from disasters or diseases.

1.2 Perceptions of Risk

Many of the concerns about the perceived contamination risks to groundwater from fracking seem to come from a misunderstanding of the subsurface, and how fracking actually works. Many O&G wells are in fact not hydraulically fractured. If the rock in contact with the wellbore is permeable enough to flow economical amounts of hydrocarbons, the well is completed and produced without fracking. These are known as "conventional" wells. Some oil and gas bearing rocks need a little help, however. Hydraulic fracturing is used in these wells to create cracks into the formation and stimulate production. These cracks provide an easier flowpath for hydrocarbons to get out of the rock and flow into the well. High-volume hydraulic fracturing (HVHF) is used on very low permeability rocks like shale to create numerous cracks deep into the formation to allow for economical rates of O&G production. Formations that require fracking to produce are called "unconventional."

The fracking operation is described in detail in the next chapter, but for the sake of this discussion, a liquid filling a well (usually water) is placed under pressure until the rock cracks. It may seem like a fantastic amount of pressure is required, but it's actually not that great. Rocks are not as strong as most people think, especially when being pulled apart. The fracture grows out away from the wellbore to a distance of about 1000 feet (300 m). The height and length of the fracture are carefully controlled for several reasons. Extending a fracture too far will prevent the proppant material (sand) from traversing the length of the crack, and the opening will simply close back up as soon as the pressure is released. Also, fracking "out of zone" into overlying or underlying non-productive rock layers is a waste of both materials and the client's money. Word gets around quickly in the oil fields, and a hydraulic fracture operator who is not capable of keeping the fracture within the productive rock units won't be in business for long.

An early assessment of the environmental concerns being raised on the HVHF process used on gas shales revealed that some of the perceived risks were being treated as actual risks, while many of the actual risks were being ignored (Soeder and Kappel 2009). One of the most significant of these perceived risks was that fracking would introduce large volumes of toxic chemicals underground, which could then rise up from below and contaminate vast tracts of aquifers that supply drinking water to thousands of people. This seemed logical to many, because fracking takes place underground, and well water comes from underground, so surely there was a risk that one would contaminate the other.

The facts are that "underground" is a big place. Aquifers that supply drinking water to domestic wells are usually quite shallow, in most cases less than a thousand feet (300 m) deep. There is a practical reason for this – groundwater gets recharged from rainfall and snowmelt on the surface infiltrating downward into the rocks. This input allows the shallow groundwater to remain fresh and drinkable. Deeper aquifers receive little to none of this freshwater input, and groundwater becomes increasingly salty with depth. Water with salt contents above 10 parts per thousand is considered brackish and undrinkable. Seawater contains about 35 parts per thousand dissolved salt, and the brines recovered at the depths of gas shales are typically six to ten times saltier than seawater (Hayes 2009; Cozzarelli et al. 2017).

Fracking of shales is done far below the base of the fresh groundwater aquifers. Because of the weight of overburden on these deep rocks, fractures form vertically and tend to grow horizontally outward in the direction of maximum principle stress. They will also grow upward for some distance until encountering a "frack barrier," which is an overlying layer of rock with physical properties that are very different from the target shale, such as a limestone. These natural barriers are included in the design of most frack jobs to constrain the growth of the fracture. Controlling the upward growth of the fracture is desirable to keep most of it contained within the productive zone of the shale.

Data on the upward growth of hydraulic fractures has been collected using microseismic monitoring techniques designed to record the motion of rocks breaking from the frack, and triangulate their location very accurately (Warpinski 2013). The data in Fig. 1.3 from the Marcellus Shale clearly show that the tops of the hydraulic fractures are thousands of feet (hundreds of meters) below the drinking water aquifers, shown in the solid shade at the top of the chart (Fisher and Warpinski 2012).

The volume of fluid pumped downhole to create a hydraulic fracture is literally not enough to grow that fracture to the surface. Field studies using tracer chemicals in the frack fluid along with geochemical and microseismic monitoring support the notion that fluids simply do not migrate vertically upward any great distance against gravity and pressure gradients except in very special or deliberate circumstances. (Hammack et al. 2014).

Once a fracked shale well begins production, the pressure gradient and direction of flow are from the formation into the well, and not upward toward shallow aquifers. There are potential leakage points for stray gas to enter the groundwater if there are wellbore integrity problems, which do seem to be more frequently associated with fracked wells. Several studies on stray gas have been published with contradictory results, however, and the jury is still out. There is also a rare (but not zero) potential for high-pressure gas to migrate to the surface through a pre-existing conduit like an abandoned well. Neither of these events are very common, and fears of pervasive gas migration from below are largely a perceived risk.

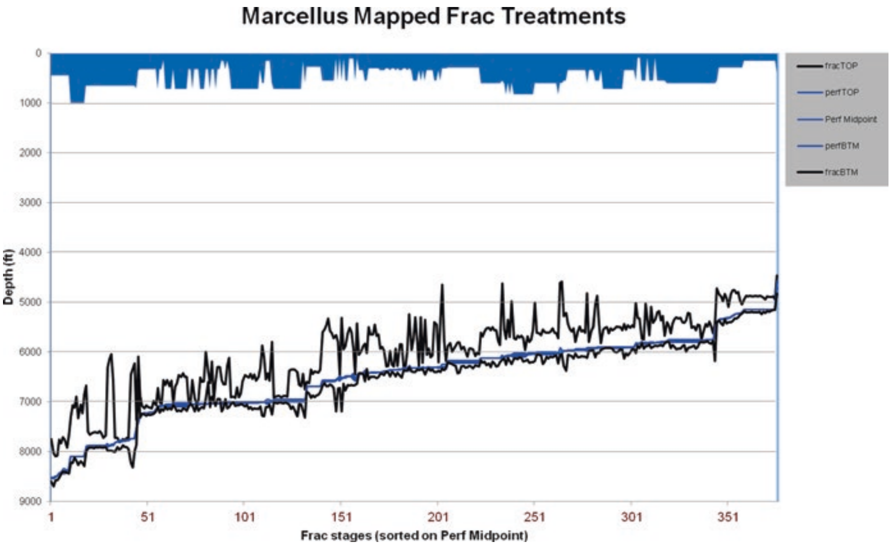


Fig. 1.3 Heights of hydraulic fractures on the Marcellus Shale measured with microseismic monitoring data plotted against the depth of the deepest freshwater aquifer in each county (solid shading at top of graph). (Data courtesy Kevin Fisher, used with permission (Fisher and Warpinski 2012))

Chemical contamination of drinking water aquifers from frack fluid additives moving up from below is even less of a risk than upward gas migration. Gas at least has a property of buoyancy, and can move upward if there is an open pathway. Frack fluid, on the other hand, is mostly water and is held down by gravity. Much of the water remains downhole, and is thought to either reside in the bottoms of fractures, or imbibe into the rock matrix (Soeder 2017). One case where frack chemicals were thought to have contaminated an aquifer in Pavillion, Wyoming, was found instead to be the result of grease, paint and other materials introduced into the aquifer during the careless installation of monitoring wells (Wyoming Department of Environmental Quality 2019).

Aquifers are at much greater risk from spills or leaks of chemicals onto the ground surface that then infiltrate into the soil and reach the water table from above, driven by gravity. These include the chemical additives used in fracking, along with the returned solids and fluids.

Other actual environmental risks related to shale gas development include air pollution as the frack fluid returns to the surface and off-gasses methane and other volatile organic compounds (VOCs) into the air, and potential biological risks as microbes in recycled frack water develop resistance to the biocides used to control downhole microbial activity, including sulfate-reducing bacteria (Soeder and Kent 2018).

Panics created by celebrity spokespeople or movie makers by publicizing perceived risks like large-scale groundwater contamination may sell books and movies, but it also results in the diversion of funds and expertise to investigate and debunk these stories. Some of this has in fact been done, but research money is tight, and scientists are stretched thin. The limited research efforts would be much better spent investigating and mitigating the actual risks based on data and published scientific studies.

There are a number of other, more general environmental risks from both conventional and unconventional O&G production that are not directly related to fracking, but are often included with it in various discussions. These are things like induced seismicity from the disposal of produced water down injection wells, GHG emissions from methane leaking out of the natural gas transmission system, petroleum leakage from pipelines, gas seepage from abandoned wells, methane leakage from deteriorated gas distribution systems in older cities, and of course the overarching concerns of fossil fuel use and climate change. All these issues are certainly important in the environmental debate over the production and use of fossil fuels; but none of them have much, if anything to do with fracking.

References

Akob, D. M., Mumford, A. C., Orem, W., Engle, M. A., Klinges, J. G., Kent, D. B., & Cozzarelli, I. M. (2016). Wastewater disposal from unconventional oil and gas development degrades stream quality at a West Virginia injection facility. *Environmental Science & Technology, 50*, 5517–5525.

Allen, D. T. (2016). Emissions from oil and gas operations in the United States and their air quality implications. *Journal of the Air & Waste Management Association, 66*, 549–575. https://doi.org/10.1080/10962247.2016.1171263.

Allshouse, W. B., McKenzie, L. M., Barton, K., Brindley, S., & Adgate, J. L. (2019). Community noise and air pollution exposure during the development of a multi-well oil and gas pad. *Environmental Science & Technology, 53*(12), 7126–7135.

Banan, Z., & Gernand, J. M. (2018). Evaluation of gas well setback policy in the Marcellus Shale region of Pennsylvania in relation to emissions of fine particulate matter. *Journal of the Air & Waste Management Association, 68*, 988–1000.

Bari, M. A., & Kindzierski, W. B. (2018). Ambient volatile organic compounds (VOCs) in Calgary, Alberta: Sources and screening health risk assessment. *Science of the Total Environment, 631/632*, 627–640. https://doi.org/10.1016/j.scitotenv.2018.03.023.

Barth-Naftilan, E., Sohng, J., & Saiers, J. E. (2018). Methane in groundwater before, during, and after hydraulic fracturing of the Marcellus Shale. *Proceedings of the National Academy of Sciences, 115*(27), 6970–6975. https://doi.org/10.1073/pnas.1720898115.

Bean, J. K., Bhandari, S., Bilotto, A., & Hildebrandt Ruiz, L. (2018). Formation of particulate matter from the oxidation of evaporated hydraulic fracturing wastewater. *Environmental Science & Technology, 52*(8), 4960–4968.

Benedict, K. B., Prenni, A. J., Sullivan, A. P., Evanoski-Cole, A. R., Fischer, E. V., Callahan, S., Sive, B. C., Zhou, Y., Schichtel, B. A., & Collett, J. L., Jr. (2018). Impact of front range sources on reactive nitrogen concentrations and deposition in Rocky Mountain National Park. *Peer Journal, 6*, e4759. https://doi.org/10.7717/peerj.4759.

Birdsell, D. T., Rajaram, H., Dempsey, D., & Viswanathan, H. S. (2015). Hydraulic fracturing fluid migration in the subsurface: A review and expanded modeling results. *Water Resources Research, 51*(9), 7159–7188.

Bloomdahl, R., Abualfaraj, N., Olson, M., & Gurian, P. L. (2014, November). Assessing worker exposure to inhaled volatile organic compounds from Marcellus shale flowback pits. *Journal of Natural Gas Science and Engineering, 21*, 348–356.

Brantley, S. L., Yoxtheimer, D., Arjmand, S., Grieve, P., Vidic, R., Pollak, J., Llewellyn, G. T., Abad, J., & Simon, C. (2014). Water resource impacts during unconventional shale gas development: The Pennsylvania experience. *International Journal of Coal Geology, 126*, 140–156.

Brantley, S. L., Vidic, R. D., Brasier, K., Yoxtheimer, D., Pollak, J., Wilderman, C., & Wen, T. (2018). Engaging over data on fracking and water quality. *Science, 359*(6374), 395–397. https://doi.org/10.1126/science.aan6520.

Butkovskyi, A., Bruning, H., Kools, S. A. E., Rijnaarts, H. H. M., & Van Wezel, A. P. (2017). Organic pollutants in shale gas flowback and produced waters: Identification, potential ecological impact, and implications for treatment strategies. *Environmental Science & Technology, 51*(9), 4740–4754.

Cahill, A. G., Steelman, C. M., Forde, O., Kuloyo, O., Ruff, E., Mayer, B., Mayer, K. U., Strous, M., Ryan, M. C., Cherry, J. A., & Parker, B. L. (2017). Mobility and persistence of methane in groundwater in a controlled-release field experiment. *Nature Geoscience, 10*(3), 289–294.

Cluff, M., Hartsock, A., Macrae, J., Carter, K., & Mouser, P. J. (2014). Temporal changes in microbial ecology and geochemistry in produced water from hydraulically fractured Marcellus shale gas wells. *Environmental Science & Technology, 48*, 6508–6517.

Costa, D., Jesus, J., Branco, D., Danko, A., & Fiuza, A. (2017). Extensive review of shale gas environmental impacts from scientific literature (2010–2015). *Environmental Science & Pollution Research*. https://doi.org/10.1007/s11356-017-8970-0. 16 p, published online April 2017.

Cozzarelli, I. M., Skalak, K. J., Kent, D. B., Engle, M. A., Benthem, A., Mumford, A. C., Haase, K., Farag, A., Harper, D., Nagel, S. C., Iwanowicz, L. R., Orem, W. H., Akob, D. M., Jaeschke, J. B., Galloway, J., Kohler, M., Stoliker, D. L., & Jolly, G. (2017). Environmental signatures and effects of a spill of untreated oil and gas wastewater in the Williston Basin, North Dakota. *Science of the Total Environment, 579C*, 1782–1795. https://doi.org/10.1016/j.scitotenv.2016.11.157.

Davies, R. J., Almond, S., Ward, R. S., Jackson, R. B., Adams, C., Worrall, F., Herringshaw, L. G., Gluyas, J. G., & Whitehead, M. A. (2014). Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation. *Marine and Petroleum Geology, 56*, 239–254. https://doi.org/10.1016/j.marpetgeo.2014.03.001.

Drollette, B. D., Hoelzer, K., Warner, N. R., Darrah, T. H., Karatum, O., O'Connor, M. P., Nelson, R. K., Fernandez, L. A., Reddy, C. M., Vengosh, A., Jackson, R. B., Elsner, M., & Plata, D. L. (2015). Elevated levels of diesel range organic compounds in groundwater near Marcellus gas operations are derived from surface activities. *Proceedings of the National Academy of Sciences, 112*(43), 13184–13189.

Eisele, A. P., Mukerjee, S., Smith, L. A., Thoma, E. D., Whitaker, D. A., & Oliver, K. D. (2016). Volatile organic compounds at two oil and natural gas production well pads in Colorado and Texas using passive samplers. *Journal of the Air & Waste Management Association, 66*, 412–419. https://doi.org/10.1080/10962247.2016.1141808.

Engelder, T., & Zevenbergen, J. (2018). Analysis of a gas explosion in Dimock PA (USA) during fracking operations in the Marcellus gas shale. *Process Safety and Environmental Protection, 117*, 61–66.

Engle, M. A., Rowan, E. L., Kraemer, T. F., & Doolan, C. (2011). *Marcellus shale flowback waters: Examination of solute and water sources*. In American Association of Petroleum Geologists eastern section meeting, September 25–27, Arlington, Virginia, Abstract.

Entrekin, S., Trainor, A., Saiers, J., Patterson, L., Maloney, K., Fargione, J., Kiesecker, J., Baruch-Mordo, S., Konschnik, K., Wiseman, H., Nicot, J.-P., & Ryan, J. N. (2018). Water stress from high-volume hydraulic fracturing potentially threatens aquatic biodiversity and ecosystem services in Arkansas, United States. *Environmental Science & Technology, 52*(4), 2349–2358.

Esswein, E. J., Snawder, J., King, B., Breitenstein, M., Alexander-Scott, M., & Kiefer, M. (2014). Evaluation of some potential chemical exposure risks during flowback operations in unconventional oil and gas extraction: Preliminary results. *Journal of Occupational and Environmental Hygiene, 11*(10), D174–D184.

Fisher, K., & Warpinski, N. (2012). Hydraulic fracture height growth: Real data. *SPE Production & Operations, 27*(1), 8–19.

Forde, O. M., Mayer, K. U., & Hunkeler, D. (2019). Identification, spatial extent, and distribution of fugitive gas migration on the well pad scale. *Science of the Total Environment, 652*, 356–366.

Gassiat, C., Gleeson, T., Lefebvre, R. R., & McKenzie, J. (2013). Hydraulic fracturing in faulted sedimentary basins: Numerical simulation of potential contamination of shallow aquifers over long time scales. *Water Resources Research, 49*(12), 8310–8327.

Goetz, J. D., Avery, A., Werden, B., Floerchinger, C., Fortner, E. C., Wormhoudt, J., Massoli, P., Herndon, S. C., Kolb, C. E., Knighton, W. B., Peischl, J., Warneke, C., de Gouw, J. A., Shaw, S. L., & DeCarlo, P. F. (2017). Analysis of local-scale background concentrations of methane and other gas-phase species in the Marcellus shale. *Elementa Science of the Anthropocene, 5*, 1. https://doi.org/10.1525/elementa.182.

Hammack, R., Harbert, W., Sharma, S., Stewart, B., Capo, R., Wall, A., Wells, A., Diehl, R., Blaushild, D., Sams, J., & Veloski, G. (2014). *An evaluation of fracture growth and gas/fluid migration as horizontal Marcellus shale gas Wells are hydraulically fractured in Greene County, Pennsylvania*. NETL-TRS-3-2014; EPAct technical report series; U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 76 p.

Hayes, T. (2009). *Sampling and analysis of water streams associated with the development of Marcellus shale gas*. Gas Technology Institute, Chicago; final report for Marcellus Shale Coalition, 49 p.

Hladik, M. L., Focazio, M. J., & Engle, M. (2014). Discharges of produced waters from oil and gas extraction via wastewater treatment plants are sources of disinfection by-products to receiving streams. *Science of the Total Environment, 466*, 1085–1093.

Ingraffea, A. R., Wells, M. T., Santora, R. L., & Shonkoff, S. B. (2014). Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012. *Proceedings of the National Academy of Sciences, 11*, 10955–11096.

Jackson, R. E., Gorody, A. W., Mayer, B., Roy, J. W., Ryan, M. C., & Van Stempvoort, D. R. (2013). Groundwater protection and unconventional gas extraction: The critical need for field-based hydrogeological research. *Groundwater, 51*(4), 488–510.

Kahrilas, G. A., Blotevogel, J., Corrin, E. R., & Borch, T. (2016). Downhole transformation of the hydraulic fracturing fluid biocide glutaraldehyde: Implications for flowback and produced water quality. *Environmental Science & Technology, 50*, 11414–11423.

Kell, S. (2011). *State oil and gas agency groundwater investigations and their role in advancing regulatory reforms: A two-state review*. Ohio and Texas: Report prepared for the Groundwater Protection Research and Education Foundation of the Ground Water Protection Council, 165 p.

Krupnick, A. J., & Echarte, I. (2017). *Health impacts of unconventional oil and gas development*. Washington, DC: Resources for the Future (RFF). 32 p.

Lefebvre, R. (2016). Mechanisms leading to potential impacts of shale gas development on groundwater quality. *Wiley Interdisciplinary Reviews: Water, 4*(1), e1188., 15 p. https://doi.org/10.1002/wat2.1188.

Litovitz, A., Curtright, A., Abramzon, S., Burger, N., & Samaras, C. (2013). Estimation of regional air-quality damages from Marcellus shale natural gas extraction in Pennsylvania. *Environmental Research Letters, 8*, 1–8.

Llewellyn, G. T., Dorman, F., Westland, J. L., Yoxtheimer, D., Grieve, P., Sowers, T., Humston-Fulmer, E., & Brantley, S. L. (2015). Evaluating a groundwater supply contamination incident attributed to Marcellus Shale gas development. *Proceedings of the National Academy of Sciences, 112*(20), 6325–6330.

McMahon, P. B., Caldwell, R. R., Galloway, J. M., Valder, J. F., & Hunt, A. G. (2015). Quality and age of shallow groundwater in the Bakken formation production area, Williston basin, Montana and North Dakota. *Groundwater, 53*, 81–94.

McMahon, P. B., Kulongoski, J. T., Wright, M. T., Land, M. T., Landon, M. K., Cozzarelli, I. M., Vengosh, A., & Aiken, G. R. (2016). *Preliminary results from exploratory sampling of wells for the California oil, gas, and groundwater program, 2014-15*. U.S. Geological Survey Open-File Report 2016-1100, 8 p. https://doi.org/10.3133/ofr20161100.

McMahon, P. B., Barlow, J. R. B., Engle, M. A., Belitz, K., Ging, P. B., Hunt, A. G., Jurgens, B. C., Kharaka, Y. K., Tollett, R. W., & Kresse, T. M. (2017). Methane and benzene in drinking-water wells overlying the Eagle Ford, Fayetteville, and Haynesville shale hydrocarbon production areas. *Environmental Science & Technology, 51*(12), 6727–6734.

McMahon, P. B., Lindsey, B. D., Conlon, M. D., Hunt, A. G., Belitz, K., Jurgens, B. C., & Varela, B. A. (2019). Hydrocarbons in upland groundwater, Marcellus shale region, northeastern Pennsylvania and southern New York, USA. *Environmental Science & Technology*, Online Publication Date: 27 June 2019. https://doi.org/10.1021/acs.est.9b01440

Meng, Q. (2017, February). The impacts of fracking on the environment: A total environmental study paradigm. *Science of The Total Environment, 580*, 953–957.

Moore, C. W., Zielinska, B., Pétron, G., & Jackson, R. B. (2014). Air impacts of increased natural gas acquisition, processing, and use: A critical review. *Environmental Science and Technology, 48*, 8349–8359. https://doi.org/10.1021/es4053472.

Mumford, A. C., Maloney, K. O., Akob, D. M., Nettemann, S., Proctor, A., Ditty, J., Ulsamer, L., Lookenbill, J., & Cozzarelli, I. M. (2020). Shale gas development has limited effects on stream biology and geochemistry in a gradient-based, multiparameter study in Pennsylvania. *Proceedings of the National Academy of Sciences, 117*(7), 3670–3677. https://doi.org/10.1073/pnas.1911458117.

Omara, M., Zimmerman, N., Sullivan, M. R., Li, X., Ellis, A., & Cesa, R. (2018). Methane emissions from 23 natural gas production sites in the United States: Data synthesis and national estimate. *Environmental Science & Technology, 52*, 12915–12925.

Orem, W. H., Tatu, C. A., Varonka, M. S., Lerch, H. E., Bates, A. L., Engle, M. A., Crosby, L. M., & McIntosh, J. (2014). Organic substances in produced and formation water from unconventional natural gas extraction in coal and shale. *International Journal of Coal Geology, 126*, 20–31.

Orem, W., Varonka, M., Crosby, L., Haase, K., Loftin, K., Hladik, M., Akob, D. M., Tatu, C., Mumford, A., Jaeschke, J., Bates, A., Schell, T., & Cozzarelli, I. (2017, May). Organic geochemistry and toxicology of a stream impacted by unconventional oil and gas wastewater disposal operations. *Applied Geochemistry, 80*, 155–167.

Osborn, S. G., Vengosh, A., Warner, N. R., & Jackson, R. B. (2011). Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proceedings of the National Academy of Sciences, 108*(20), 8172–8176.

Pekney, N., Reeder, M., & Mundia-Howe, M. (2018). Air quality measurements at the Marcellus shale energy and environment laboratory site. *EM The Magazine for Environmental Managers*, August 2018, Air & Waste Management Association, 5 p.

Pétron, G., Karion, A., Sweeney, C., Miller, B. R., Montzka, S. A., Frost, G. J., Trainer, M., Tans, P., Andrews, A., Kofler, J., Helmig, D., Guenther, D., Dlugokencky, E., Lang, P., Newberger, T., Wolter, S., Hall, B., Novelli, P., Brewer, A., Conley, S., Hardesty, M., Banta, R., White, A., Noone, D., Wolfe, D., & Schnell, R. (2014). A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin. *Journal of Geophysical Research-Atmospheres, 119*, 6836–6852.

Phan, T. T., Capo, R. C., Stewart, B. W., Graney, J. R., Johnson, J. D., Sharma, S., & Toro, J. (2015). Trace metal distribution and mobility in drill cuttings and produced waters from Marcellus shale gas extraction: Uranium, arsenic, barium. *Applied Geochemistry, 60*, 89–103.

Reagan, M. T., Moridis, G. J., Keen, N. D., & Johnson, J. N. (2015). Numerical simulation of the environmental impact of hydraulic fracturing of tight/shale gas reservoirs on near-surface groundwater: Background, base cases, shallow reservoirs, short-term gas, and water transport. *Water Resources Research, 51*, 2543–2573. https://doi.org/10.1002/2014WR016086.

Renock, D., Landis, J. D., & Sharma, M. (2016). Reductive weathering of black shale and release of barium during hydraulic fracturing. *Applied Geochemistry, 65*, 73–86.

Rodriguez, R. S., & Soeder, D. J. (2015). Evolving water management practices in shale oil & gas development. *Journal of Unconventional Oil and Gas Resources, 10*, 18–24.

Rowan, E. L., & Kraemer, T. F. (2012). *Radon-222 Content of natural gas samples from Upper and Middle Devonian sandstone and shale reservoirs in Pennsylvania – Preliminary data*. U.S. Geological Survey OFR 2012–1159, 6 p, http://pubs.usgs.gov/of/2012/1159.

Siegel, D. I., Azzolina, N. A., Smith, B. J., Perry, A. E., & Bothun, R. L. (2015). Methane concentrations in water wells unrelated to proximity to existing oil and gas wells in northeastern Pennsylvania. *Environmental Science & Technology, 49*, 4106–4112.

Soeder, D. J. (2015). Adventures in groundwater monitoring: Why has it been so difficult to obtain groundwater data near shale gas wells? *Environmental Geosciences, 22*(4), 139–148.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Kappel, W. M. (2009). *Water resources and natural gas production from the Marcellus shale*. U.S. Geological Survey, Fact Sheet 2009–3032, 6 p.

Soeder, D. J., & Kent, D. B. (2018). When oil and water mix: Understanding the environmental impacts of shale development. *GSA Today, 28*(9), 4–10.

Soeder, D. J., Sharma, S., Pekney, N., Hopkinson, L., Dilmore, R., Kutchko, B., Stewart, B., Carter, K., Hakala, A., & Capo, R. (2014). An approach for assessing engineering risk from shale gas wells in the United States. *International Journal of Coal Geology, 126*, 4–19.

Theodori, G. L. (2008). *Public perception of the natural gas industry: Insights from two Barnett shale counties*. Paper SPE 159117-MS, presented at Society of Petroleum Engineers Annual Technical Conference and Exhibition, 21–24 September, Denver, Colorado, 5 p.

Thomas, L., Tang, H., Kalyon, D., Aktas, S., Arthur, J. D., Blotevogel, J., Carey, J. W., Filshill, A., Fu, P., Hsuan, G., Hu, T., Soeder, D., Shah, S., Vidic, R., & Young, M. H. (2019). Toward better hydraulic fracturing fluids in energy production: A review of sustainable technologies and reduction of potential environmental impacts. *Journal of Petroleum Science and Engineering, 173*, 793–803.

Townsend-Small, A., Marrero, J. E., Lyon, D. R., Simpson, I. J., Meinardi, S., & Blake, D. R. (2015). Integrating source apportionment tracers into a bottom-up inventory of methane emissions in the Barnett shale hydraulic fracturing region. *Environmental Science & Technology, 49*, 8175–8182.

USEPA. (2016). *Hydraulic fracturing for oil and gas: Impacts from the hydraulic fracturing water cycle on drinking water resources in the United States (Final Report): EPA/600/R-16/236F*, Washington, DC, 664 p.

U.S. Department of Energy (2012). *The United States carbon utilization and storage atlas*, Fourth Edition, DOE Office of Fossil Energy, Washington, DC, 129 p.

Vengosh, A., Jackson, R. B., Warner, N., Darrah, T. H., & Kondash, A. (2014). A critical review of the risks to water resources from unconventional shale gas development and hydraulic fracturing in the United States. *Environmental Science & Technology, 48*, 8334–8348.

Vidic, R. D., Brantley, S. L., Vandenbossche, J. M., Yoxtheimer, D., & Abad, J. D. (2013). Impact of shale gas development on regional water quality. *Science, 340*, 826 (1235009).

Warner, N. R., Jackson, R. B., Darrah, T. H., Osborn, S. G., Down, A., Zhao, K., White, A., & Vengosh, A. (2012). Geochemical evidence for possible natural migration of Marcellus formation brine to shallow aquifers in Pennsylvania. *Proceedings of the National Academy of Sciences, (PNAS), 109*(30), 11961–11966.

Warpinski, N. R. (2013). Understanding hydraulic fracture growth, effectiveness, and safety through microseismic monitoring. In A. P. Bunger, J. McLennan, & R. Jeffrey (Eds.), *Effective and sustainable hydraulic fracturing*. Rijeka: InTech. 1072 p. (ISBN 978-953-51-1137-5).

Werner, A. K., Vink, S., Watt, K., & Jagals, P. (2015). Environmental health impacts of unconventional natural gas development: A review of the current strength of evidence. *The Science of the Total Environment, 505*, 1127–1141.

Williams, P. J., Reeder, M., Pekney, N. J., Risk, D., Osborne, J., & McCawley, M. (2018). Atmospheric impacts of a natural gas development within the urban context of Morgantown, West Virginia. *Science of the Total Environment, 639*, 406–416. https://doi.org/10.1016/j.scitotenv.2018.04.422.

Woda, J., Wen, B., Oakley, D., Yoxtheimer, D., Engelder, T., Castro, M. C., & Brantley, S. L. (2018). Detecting and explaining why aquifers occasionally become degraded near hydraulically fractured shale gas wells. *Proceedings of the National Academy of Sciences, 115*(49), 12349–12358. https://doi.org/10.1073/pnas.1809013115.

Wyoming Department of Environmental Quality (2019). Final Pavillion, Wyoming gas field domestic water wells report on recommendations for further investigation: Cheyenne, Wyoming: Wyoming DEQ Water and Waste Advisory Board, 45 p. (https://deq.wyoming.gov/wqd/pavillion-investigation/resources/investigation-final-report/).

Yan, B., Stute, M., Panettieri, R. A., Jr., Ross, J., Mailloux, B., Neidell, M. J., Soares, L., Howarth, M., Liu, X., Saberi, P., & Chillrud, S. N. (2017). Association of groundwater constituents with topography and distance to unconventional gas wells in NE Pennsylvania. *Science of the Total Environment, 577*, 195–201.

Ziemkiewicz, P. F., Quaranta, J. D., Darnell, A., & Wise, R. (2014, January). Exposure pathways related to shale gas development and procedures for reducing environmental and public risk. *Journal of Natural Gas Science and Engineering, 16*, 77–84. https://doi.org/10.1016/j.jngse.2013.11.003.

Chapter 2
What Is Fracking?

Since this book may reach a rather wide audience, and with apologies to those readers with a technical background, it is important for everyone to understand that oil and gas are recovered from porous rocks underground. Despite the way it is often shown on cross-sectional diagrams, oil does not occur in underground caves or lakes. Some man-made caverns in salt domes are used for storage of the U.S. Strategic Petroleum Reserve, but oil and gas production itself comes out of porous rock.

Nearly everyone has seen water soak into the sand when waves wash up on a beach. The water has gone into the empty pore spaces that are present between the sand mineral grains (think of the spaces between billiard balls racked in a triangle). Hydrocarbon resources occur in similar spaces in porous sedimentary rocks like sandstone or limestone. Sometimes these pore spaces are very small, making it difficult for the fluids in them to move. Such rocks are said to be “tight,” and fracking was invented to overcome this.

The term “fracking” originated as drillers’ slang for the process of hydraulic fracturing, invented in 1947 by a fellow named Floyd Farris working at Stanolind Oil and Gas in the Hugoton gas field in Grant County, Kansas (Montgomery and Smith 2010). Hydraulic fracturing was designed to create long cracks in the rock underground to allow oil and gas to flow more easily into a well. Farris was using crude oil and naphtha gel as the frack fluid for his experiments. He discovered that if he filled up a well with this liquid and then gradually increased the pressure on it, the strength of the rock would be exceeded, and a crack would form.

Earlier methods to crack open rocks had used explosives, but these tended to just shatter the rock near the wellbore and not penetrate very far into the formation. The explosives method had been patented at the end of the Civil War by Colonel Edward Roberts, who noted that artillery shells exploding in water transmitted shock waves more efficiently than those hitting land, and would often break rocks. He used a gunpowder “torpedo” (later dynamite) lowered into an oil well on a wireline with a sliding weight to set off the charge (Eschner 2017). Although the treatment reportedly increased production from some wells by as much as 1200%, Roberts charged $200 per torpedo (a princely sum in the late nineteenth century) plus 15% of the

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_2

produced oil. The operation itself was rather simple, so unlicensed practitioners took to dropping dynamite or sometimes just pouring straight nitroglycerine into wells to achieve the same effect. Roberts responded by hiring Pinkerton detectives and an army of lawyers to enforce his patent. The freelancers began working at night without lanterns to avoid being seen by the Pinkertons, using only moonlight to illuminate their operations. Fumbling around in the dark with nitroglycerin was extremely dangerous, as many learned the hard way. Some contemporary advice urged that before attempting this task, practitioners should both update their will and procure an empty cigar box for their grieving families to gather up the remains.

Besides being much safer, Farris' hydraulic fractures were superior because they extended a crack far into the rock unit, creating long, high permeability flowpaths that could return substantial amounts of oil and gas to the well. Farris and Stanolind Oil received a patent for hydraulic fracturing in 1949, and Stanolind promptly sold the process to the Halliburton Oil Well Cementing Company. It was offered as a service by Halliburton that same year, and the first commercial hydraulic fracturing operations were performed on wells in Duncan, Oklahoma and Holliday, Texas in 1949 using Farris' technique with oil-based fluids (Fisher 2010). Halliburton developed the modern, water-based method of hydraulic fracturing in 1953 (Montgomery and Smith 2010).

Hydraulic fracturing is an engineering process known as "reservoir stimulation," which seeks to improve the recovery of hydrocarbons from a reservoir rock by making it easier for the fluids to move (Economides and Nolte 2000). The goal of hydraulic fracturing is to contact large volumes of reservoir rock with permeable flowpaths that allow oil and gas to flow to a well. A second type of reservoir stimulation is known as matrix stimulation, which restores permeability to the rock near a borehole that has suffered formation damage during the drilling process. It typically uses acid treatments to dissolve out the mud and cement material plugging the pores, or to create new holes through the matrix to bypass the damaged zone (Economides and Nolte 2000). Reservoir stimulation is part of the "completion" activity on a well (after drilling is done but before production starts). The O&G industry has always used the word "fracking" only in reference to the actual hydraulic fracturing stimulation process.

2.1 The Frack vs. Frac Controversy

Environmental groups opposed to the development of shale gas and tight oil have hijacked the term "fracking" as a trigger word to describe the entire shale gas production process, from the first bulldozer that clears off the well pad to the final installation of a meter run before connecting the produced gas to a pipeline. The recent remake of the Battlestar Galactica TV series used "frak" as a substitute cuss word, and shale gas opponents have adopted it in that context (i.e. "Don't frack with New York"). In environmental organizations, the people who actually attend rallies and protests are known as "activists." Fracking opponents typically call themselves "fracktivists."

The O&G industry objects to this misuse of the term, pointing out that if someone thinks a bulldozer clearing off a drill pad is "fracking," then they don't know enough about the O&G business to have (in their words) an "adult conversation" about shale gas development. Many people suspect that at least some of the protestors know that they are improperly using the word, but continue to do so deliberately in a juvenile manner to irritate the O&G industry. However, not everyone is aware of the origin of the term, and the misunderstanding of "frack" contributes to the problem of shale gas proponents and opponents talking past one another. It further deepens the already significant failure to communicate that exists between the two sides.

In response, industry has changed the spelling of the term to "frac" (i.e. dropping the "k"). The reasoning was childish and the usage awkward, with bent or broken words like frac'ed or frac'ing being used to change tense or as modifiers. O&G opponents, on the other hand, have further embraced the use of "frack" to describe essentially the entire shale gas industry, and speak darkly about the transmission of fracked gas throughout the United States. How they are able to distinguish fracked gas from non-fracked gas, when both have the exact same chemistry and identical Btu values to meet pipeline specs remains a mystery.

If all of this seems silly and trivial, it is. Both frack and frac are made-up slang words. Using either one is equally valid, since neither word is in the dictionary and therefore not required to follow any particular rules. As trivial as it may seem, however, the spelling of this term can have significant consequences. A person is often immediately assigned to one camp or the other depending on whether or not they employ the "k." If you talk about "fracks," the O&G industry assumes you are a protestor who is viscerally and fanatically opposed to energy development. On the other hand, if you want to discuss "fracs," the environmental crowd will tag you immediately as a pro-industry shill.

Even the technical literature makes a distinction. Technical publications that serve the O&G industry like those from the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Engineers (SPE) consistently use the spelling "frac" when they allow the term. Environmental and ecological publications typically spell it "frack." Some people have sought to avoid the controversy altogether by laboriously spelling out "hydraulic fracturing" every time and not using either version of the slang.

For the purposes of this book, English words that sound like "frack" are generally spelled with the k. Frack is much closer grammatically to spellings like back, slack, and crack. "Frac" without the k is similar to some French words like "cul-de-sac," and "lac," but in general, ending an "ack" word in English with a "c" just doesn't work. Therefore, since this is a made-up term anyway, and I don't intend to write out "hydraulic fracturing" every time, the usage of frack in this manuscript will include spelling with the k. Make no mistake, however – the definition of the term is in line with the O&G industry in that it refers only to the reservoir stimulation process, not the entire shale gas development process. Calling anything other than hydraulic fracturing a frack is a misuse of the term, and more importantly, it makes no sense.

2.2 Why Frack?

So why even do this? Oil and gas wells had been around for 90 years before fracking was ever invented. Couldn't the whole controversy be avoided by just drilling and producing wells without reservoir stimulation? Well, yes, but the wells that can be produced without hydraulic fracturing make up less than half of our current hydrocarbon production. To recover shale gas (70% of our current gas production) and tight oil (50% of our current oil production) from the extremely low permeability rocks that make up these reservoirs, hydraulic fracturing is absolutely essential.

Shale is a sedimentary rock type composed of tiny flakes of clay, grains of quartz, organic material and other minor minerals (Fig. 2.1). It was deposited in quiet water as mud that was buried and then lithified into rock. Because shale has a very small grain size, the pore spaces between the grains are also very small (Civan and Devegowda 2015).

Organic material deposited with the shale created hydrocarbons as the sediment was buried, heated, and turned into rock. Prior to the twenty-first century, nearly all of the oil and gas produced in the world had migrated out of these shales (known as "source rocks") over geological time scales and became trapped in more permeable rocks like sandstones made of coarser grains with larger pores. The permeable rocks are known as "conventional" reservoirs, because they can be produced by simple drilling without fracking. The American dependence on imported oil that led to the 1970s energy crisis was caused by the depletion of conventional O&G reservoirs in the United States.

Shale and other low permeability rocks are known as "unconventional" reservoirs because stimulation treatments such as fracking are required for recovery.

Fig. 2.1 Fresh exposure of lower Marcellus Shale in Seneca Stone Company quarry in upstate New York. Rock hammer for scale is 13 inches (33 cm) in length. (Photographed in 2012 by Dan Soeder)

Unlike conventional reservoirs, these rocks don't need any kind of special structural or stratigraphic traps to contain oil and gas – the hydrocarbons are held within the tiny pores and adsorbed onto organic particles. In fact, the USGS calls these "continuous reservoirs" because they will produce hydrocarbons from just about anywhere in the formation if the proper stimulation techniques are applied (Charpentier and Cook 2011). It was recognized during the energy crisis that if a way could be found to directly extract oil and gas economically from the huge volumes of shale and other tight rocks in the U.S., they would represent a very large hydrocarbon resource indeed (Schrider and Wise 1980). The key to shale gas production is that the source rock is the reservoir rock.

The difficulty of extracting hydrocarbons from tight rocks like shale can be understood by comparisons with the more permeable conventional reservoir rocks. Measurements of the ability for a porous rock to transmit fluid were first defined in 1856 by Henry Darcy, a hydraulic engineer working on the municipal water system for Dijon, France (Freeze and Cherry 1979). Darcy equated the flow of water through the pore system of a rock or sediment with the flow of electrons through metals. He developed an empirical relationship for what he called "hydraulic conductivity," which is similar in structure to Ohm's Law for electrical conductivity.

Darcy's Law is written as:

$q = kA(\Delta P/\mu L)$

Where q = flow in cubic cm per second, k = permeability (darcy or d), A = cross-sectional area in square cm, ΔP = differential pressure in atmospheres per cm of length, μ = fluid viscosity in centipoise (cP), and L = flowpath length in cm. To solve for permeability (k) it can be rewritten as:

$k = q\mu L/A(\Delta P)$

The basic unit of permeability is called the darcy. It is defined by a specific flow rate when all the other variables are set to fixed values. Thus, a porous medium with a permeability (k) of one darcy will discharge fluid that has a viscosity (μ) of 1 cP (conveniently the viscosity of water at room temperature) from a cross sectional area (A) of one square centimeter at a rate (q) of 1 cm^3 per second under a pressure gradient (ΔP) of 1 atm per centimeter of length (L). This is illustrated graphically in Fig. 2.2. The Standard International (SI) unit for permeability is the square meter, or m^2; one darcy is equal to about 10^{-12} m^2.

To obtain rock permeability in a lab, one needs to measure the dimensions of the sample, the differential pressure across it, the fluid viscosity, and the discharge flow rate. To determine gas permeability, a fixed ΔP is set for the measurement, q is measured and k is calculated. To determine permeability to water or another incompressible liquid, q is fixed for the measurement (a constant rate of liquid flow can be obtained with a syringe pump) and ΔP is measured to calculate k.

Because Henry Darcy was performing experiments with water flowing through columns of loose sand, the darcy is actually a fairly large unit, and conventional oil and gas reservoir rocks like sandstone or limestone typically have permeabilities a thousand times lower, in the range of 10^{-3} d, or a millidarcy (md). Permeabilities in tight sandstones or dense limestones are commonly a thousand times lower still, around a microdarcy (μd) or 10^{-6} darcy (Randolph 1983). Extremely tight rocks like

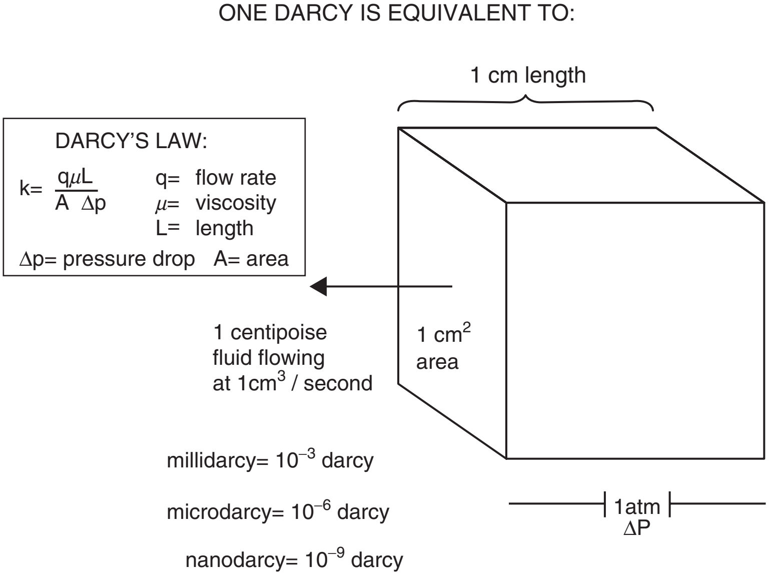


Fig. 2.2 Visualization of the physical parameters used to define Darcy's law of permeability. (Sketch by Dan Soeder)

shale have permeabilities as low as a nanodarcy (nd), or 10^{-9} darcy (Civan and Devegowda 2015). Commercial amounts of O&G are successfully being produced from shales this tight.

The SI permeability units are generally not used on oil and gas resources because the conversion requires working with extremely small numbers: one md equals about 10^{-15} m^2, one µd is about 10^{-18} m^2 and one nd is 10^{-21} m^2. Most researchers consider the darcy to be a more practical unit, especially when expressed as md, µd, or nd (Soeder 2017).

The technical challenge of oil and gas production from shale can be illustrated with the sketch shown above in Fig. 2.2. With differential pressure, fluid viscosity, cross-sectional area and flowpath length set at the parameters defined by Henry Darcy, at a permeability of one darcy the cubic centimeter of porous media shown in the figure will discharge 1 cm^3 of fluid in 1 second. If the original cube is replaced with a conventional oil and gas reservoir sample having a permeability of one millidarcy (md) and all other conditions remain the same, the discharge of 1 cm^3 of fluid would require a thousand seconds, or about 17 minutes. A one microdarcy (µd) tight gas sandstone placed in the block would require a million seconds to discharge 1 cm^3 of fluid, equivalent to roughly 11 ½ days. Finally, if a one nanodarcy (nd) shale sample is placed in the block, the discharge of 1 cm^3 of fluid would require a billion seconds, or approximately 32 years. The permeability of nanodarcy gas shale is a thousand times lower than tight sand and a million times lower than that of a conventional gas reservoir rock, making the ascent of shales as the dominant source of hydrocarbon production in the United States all the more astounding.

The engineering challenges that had to be overcome to produce hydrocarbons from shale were formidable. Shale is a dual-porosity system, with most of the pore volume located within the matrix, and less than 1% in natural fractures (Soeder 1988). Thus, the matrix pores provide storage for hydrocarbons, while the fracture porosity provides flowpaths. It is difficult for oil or gas to move out of the matrix pores – some of these are so small that the motion is by molecular diffusion rather than flow, and hydrocarbon migration from some of the smaller pores may even take place molecule by molecule. However, to produce economical amounts of O&G from shale, hydrocarbons trapped in the tiny matrix pores must be recovered. Overpressured gas in the natural fracture system typically provides high levels of initial production that drops off quickly as the fractures deplete. The long-term production of shale wells requires hydrocarbons to move from the matrix and into the production well. The goal of the reservoir stimulation process is to make it easier for hydrocarbons to flow out of the matrix and into permeable pathways like fractures that are connected to the wellbore.

A number of researchers have explored the pore structures of shale, and the processes of liquid and gas movement through these rocks (i.e. Josh et al. 2012). Shale pores are generally classified as follows: (1) interparticle porosity between grains, crystals or clay flakes, (2) intraparticle porosity within pyrite framboids, clay aggregates, dissolution pores on the rims of crystals, and moldic pores within fossils, pellets, or crystals, (3) porosity within kerogen or other organic matter, and (4) microfracture porosity (Loucks et al. 2012). Many of these pores are less than a micrometer to only a few nanometers in size (Rodriguez et al. 2014).

Darcy's Law allows for a limited number of adjustments to be made on the variables to increase q, the discharge rate of fluids at very low permeability (k) values. Higher q values can be obtained by increasing the cross-sectional surface area (A), reducing the flowpath length (L), decreasing the viscosity (μ) of the fluid, and boosting the differential pressure (ΔP). Although the viscosity of oil in a reservoir can be altered a number of different ways, changing the viscosity of natural gas contained within a rock pore system is not practical. The engineers could only work with A, L, and ΔP in their attempts to develop shale gas resources.

This is where fracking became important. Hydraulic fracturing was used to create closely-spaced, high-permeability flowpaths into the rock. These reduced the distance or flowpath length (L) that the hydrocarbons had to follow to exit the matrix, which according to Darcy's Law increases q. The flat hydraulic fracture faces penetrating the rock also expanded the surface area (A) of the matrix in contact with high permeability flowpaths, again increasing q. Finally, lower pressures in the fracture system connected to the production well raised the differential pressure (ΔP) between the fracture and the matrix, also increasing q.

Thus, all of these factors together enabled the hydrocarbons to flow more easily from the shale matrix, and when a sufficient volume of rock had been treated, economical quantities of oil and gas could be recovered from a well. This had been known in theory for quite some time, but achieving it in practice turned out to be immensely challenging (Soeder 2017).

2.3 Hydraulic Fracturing Step by Step

Hydraulic fracturing is not a new technology. As mentioned earlier, it was invented in 1947 and has been in use for more than 70 years. Fracking operations are carried out by what the O&G industry calls "service companies." These include Halliburton, Schlumberger, Baker Hughes, CalFrac, FTS and others. Many of these companies offer wellbore cementing, well logging, matrix stimulations, and other completion services in addition to fracking.

Hydraulic fracturing operations are performed by highly trained, experienced crews using specialized equipment. Like many other oilfield workers, frack crews work around the clock, 7 days a week on "tours" that last until the job is completed. Fracking is all they do, and they move themselves and their equipment from well pad to well pad, often on tight schedules due to a shortage of crews or to avoid the onset of bad weather.

The notion promulgated by some O&G opponents that the people who perform fracking are careless, clueless, or irresponsible couldn't be further from the truth. Many of these folks are engineers holding at least Bachelor's degrees, some are licensed Professional Engineers (PE), and most have years of relevant experience. The people who design, manage and monitor the actual hydraulic fracturing job on site are all educated professionals. Hydraulic fracturing is an expensive and logistically complicated process, and there is plenty of competition for business. Frack crews strive to complete the stimulation according to design specifications, maintain the fracture within the target zone, and use the minimum volumes of water, sand and chemical additives necessary to create the desired frack. Mistakes do happen, but companies who waste materials or frack into non-productive zones cost the operating companies too much money and don't last very long.

The logistics are formidable – all of the needed materials, sometimes including the water have to be transported out to well locations, which are often in remote areas. Everything needs to be inventoried and prepared for use, and then transported to the next location after the hydraulic fracturing operation is completed. Many of the fracking operations are done in "stages," which means that multiple, individual fracks take place at different zones within a single well. In the case of shale production where directional boreholes are used, there may be a half dozen or more wells on a single pad, and all of them require staged fracks.

When wells are drilled, lengths of steel pipe known as "casing" are inserted into the borehole and cemented in place. Casing is designed to support the borehole walls against collapse, and provide an impervious barrier to prevent the unwanted migration of fluids both into and out of the well. It is the main protection for groundwater from contamination.

Each diameter of casing is known as a "string" and multiple strings of casing are typically run into a borehole, with each successive string being narrower so it can fit inside all the others. Before drilling even starts, a large, corrugated pipe called the conductor casing is often set upright a few meters deep in an excavation to hold back unconsolidated soil, isolate very shallow and transient groundwater, and provide an electrical ground for the rig. Conductor casing may or may not be used depending on the conditions at an individual site.

The “spud” occurs when the drill bit first penetrates the ground surface. The borehole is usually drilled down a few hundred feet (a few dozen meters) to the base of the drinking water aquifers before stopping, and a casing string known as the surface casing is set and cemented into place to protect the groundwater. State regulations mandate the depth to which surface casing must be set for groundwater protection, and this varies from state to state. In many states, drilling cannot proceed until the surface casing has been inspected, tested, and certified.

The borehole is drilled vertically below the surface casing to the target depth. For horizontal boreholes, typically used in shale, the “kick-off point” is where the well begins to deviate from the vertical “tophole” and curve into horizontal or “lateral” drilling. A string of casing is usually set from the surface to a depth of about a kilometer. This “intermediate” casing is used to support the borehole walls and to prevent any brines or hydrocarbons in shallower rocks from entering the well. Shale wells without this casing are known as “open-hole” completions, but because of earlier problems with stray gas migration into shallow groundwater from uncased holes, the majority of new wells use the intermediate string of casing. The well is then taken through a gentle curve known as the “heel” and drilled horizontally out to the “toe” at the end of the lateral (Fig. 2.3).

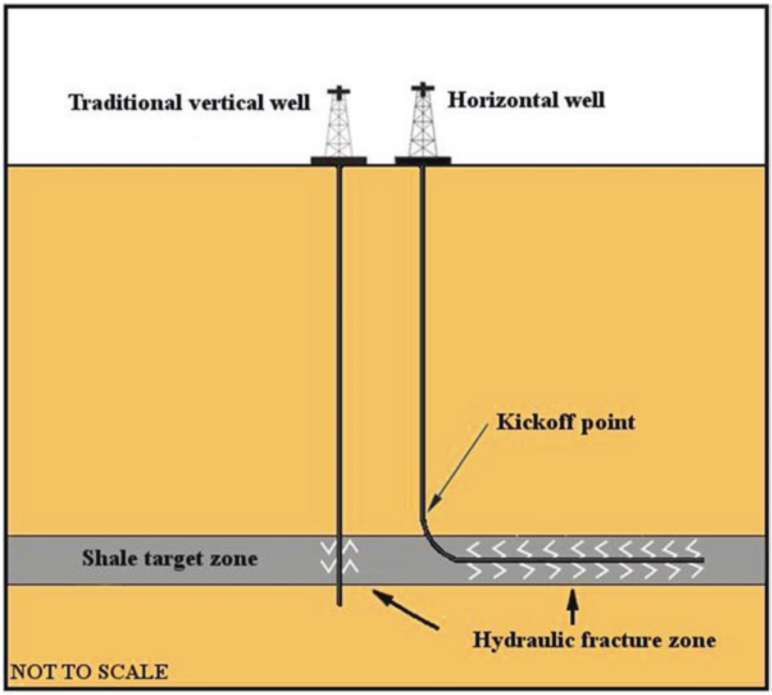


Fig. 2.3 Schematic comparing the configuration of a conventional vertical well with a horizontal shale well. (Modified from Soeder and Kappel (2009))

Modern drill rigs use a hydraulically-driven bit in a bottomhole assembly to drill vertically down from the surface, build the heel curve and create the horizontal borehole all in a single operation without having to pull out of the hole and change components. The final string of casing inserted and cemented into the completed well is called the production casing, and it runs from the depth of the target formation (or the toe of the lateral) all the way back to the surface. To produce the oil or gas from the rock, holes known as "perforations" are created in the production casing to allow hydrocarbons to enter the well.

The holes are made using a perforating gun or "perf gun." In the old days, actual bullets were employed, hence the name. Modern perf guns use shaped demolition charges consisting of up to 60 g of RDX, AMX, or HNS, all of which are military-grade high explosives. The guns consist of a remotely-operated detonator connected to demolition charges inside a downhole carrier unit that is designed to contain the explosive debris. The blasts create holes in the casing between 6 and 20 mm in diameter (¼ to ¾ inch), with a depth into the rock from 10 cm (4 inches) to more than a meter, and there are generally 12–36 holes created per meter of length (4–12 holes per foot). Successive shots are turned at an angle of about 60° from the previous shot to spiral the perforations around the casing.

As part of the preparations for hydraulic fracturing, a massive, high-pressure wellhead known as a frack gate (Fig. 2.4) is installed at the surface, just above the main casing and connected to the production tubing. It is designed to allow equipment and materials to pass while controlling the entry and exit of fluids. The main wellhead pressure valves at the top of the production casing are left wide open during the frack, because the proppant sand being pumped downhole and returning afterward would abrade any obstruction in its path (these valves can be seen in Fig. 2.4 immediately below the frack gate). Abrasion by moving sand is a concern on all hydraulic fracturing stimulations, but especially in horizontal wells. Although production casing is typically made from half-inch (1.25 cm) thick, high-tensile strength steel pipe that meets American Petroleum Institute (API) standards, there have been rare cases where a hole was abraded in the heel by proppant sand particles racing through the turn.

In a conventional vertical well, the hydraulic fractures extend outward from either side of the wellbore as vertical cracks called "wings" in the direction of maximum horizontal compressive stress. The wings may extend as far as 1000 feet (300 m) in either direction from the borehole (Ahmed et al. 1979). Fractures break in the maximum stress direction because the only way the walls can move apart to create the crack is in the minimum compressive stress direction at right angles to this. For example, imagine compressing a walnut in a nutcracker. The nut will crack in the direction of maximum compression on a line between the jaws. However, the two sides of the crack will move apart in the direction of minimum stress, or perpendicular to compression, and the shell fragments will fly out the sides of the nutcracker.

In a related, similar stress issue, if a frack is attempted at a depth that is too shallow, the net overburden pressure will be less than the strength of the rock, and the rock will not break vertically. Compressive stress downward is needed to force the

Fig. 2.4 A massive wellhead known as a frack gate on a Marcellus Shale well in Pennsylvania with geologist Bill Schuller standing nearby for scale. (Photographed in 2011 by Dan Soeder)

walls of the fracture to move apart in a horizontal direction to create a vertical crack. A hydraulic fracture created at too shallow of a depth will uplift the rock vertically and form a horizontal crack. This is known as "pancaking" in industry parlance, and is to be avoided because horizontal fractures are very inefficient for production. A minimum overburden thickness of 2500 feet (800 m) is considered necessary to obtain a vertical hydraulic fracture. Most fracks are performed in target formations that are two to four times deeper than this minimum.

High-volume hydraulic fracturing (HVHF) is the type of fracking operation usually carried out on horizontal shale wells. These use substantially greater quantities of water, sand, and chemicals than fracks done in vertical wells, even so-called "massive" hydraulic fractures. Because vertical wells only penetrate a limited thickness of the target formation, fracks are typically limited to only one stage for creating vertical cracks into the target zone. Horizontal wells, on the other hand, penetrate long lateral lengths of the target formation, allowing HVHF to be done in multiple stages or increments. Each stage extends through a length of about 500 feet (150 m) of borehole. The first stage begins at the toe end of the lateral and successive stages work backward toward the heel. Each stage receives a set of perforations followed by the hydraulic fracture treatment. It is then sealed off while the next stage is treated. The seals are removed for production after all stages have been fracked.

The descriptions of the reservoir stimulation steps that follow are those that were developed by Mitchell Energy for the successful production of gas from the Barnett Shale in Texas during the late 1990s that started the shale gas revolution. Drilling, completion, stimulation, and production techniques are constantly evolving as companies seek ways to improve efficiencies and reduce costs, and this book would be obsolete before the ink was dry if the latest trends were included. For example, one technique said to be fairly common on newer wells at this writing is to hold the frack pressure on a zone for extended periods of time to "let it soak." In a month or a year, the "latest thing" will be something else. Nevertheless, the historical steps developed by Mitchell for successful hydrocarbon production from shale provide useful lessons in shale gas engineering and a good overview of the issues encountered when stimulating an ultra-tight rock.

Step 1. Prep and Cleanout The hydraulic fracturing process starts by cleaning the perf holes using a 15% solution of muriatic or hydrochloric acid (HCl). Perforating casing with high explosives tends to force pieces of steel and pulverized cement into the formation, and these must be removed. While the acid is cleaning out the perforations, the hydraulic fracturing system undergoes pressure testing and all the equipment is calibrated.

Electronic instrumentation is used to collect real-time measurements of pressure data at the wellhead, downhole, and in the annulus behind the production casing. A flow meter on the blender measures the volume of fluid pumped downhole, and a densometer measures the amount of sand in the fluid. Engineers closely watch the wellhead, annulus, and bottomhole pressures, pump rate, fluid density and material parameters throughout the frack.

The high- and low-pressure systems on a hydraulic fracturing operation are plumbed separately, so fluid from one cannot get into the other unless the operator allows it. The working parts of the pumps used to generate the frack pressure consist of positive displacement pistons inside high-strength steel cylinders. The rate at which these pistons advance can be controlled very precisely to maintain a specific flow volume and/or pressure. The migration of frack fluid into the formation is known as "leak-off" and the pumps have to be precise enough to make up for this volume loss while maintaining pressure. Safety cutoffs are in place if pressure or volume parameters are exceeded, and the high-pressure parts of the system also have relief valves to prevent critical components from blowing out.

Step 2. Fracture Initiation The well is filled with water containing a friction-reducing chemical additive called polyacrylamide, which creates an extremely slippery liquid known as "slickwater." Slickwater is used to reduce pressure losses due to friction as the frack fluid is pumped from the surface to the formation down a long string (often several kilometers) of production casing. Downhole pressure losses can be as much as 50% without this treatment. The frack fluid is under a hydrostatic pressure gradient in the borehole of about 0.5 psi/foot of depth (22.6 kPa/m). This is due to the weight of the water above pushing down on the water below. The pump trucks gradually increase pressure on the fluid until it exceeds the formation strength (Fig. 2.5). The pressure at which the rock cracks open is called the breakdown pressure, and represents the initiation of the hydraulic fracture.

Step 3. Pumping the Frack Because water is virtually incompressible, as soon as the fractures are created and water begins flowing into them, more water must be added at the surface to maintain the pressure. The initial part of the fracture, called the pad, is made with slickwater only. Behind this, as the fracture opens up, sand is pumped in with the water to act as a proppant. The proppant holds the fracture open after the pressure has been released.

The water, chemical additives, and sand are mixed at the surface in a blender to a specific density. The rate at which the proppant sand is pumped into the frack is critical—too fast, and the proppant will be spread thinly through the formation and be ineffective; too slowly and the sand won't remain in suspension in the frack fluid, settling to the bottom of the well in a process called a screen-out. Fine-grained sand is pumped into the fracture initially, followed by coarser sand as the fracture system develops.

Fig. 2.5 Initiating a hydraulic fracture in the Marcellus Shale at a wellsite in southwestern Pennsylvania. (Photographed in 2011 by Dan Soeder)

Water pressure and pump rates are maintained until the hydraulic fractures extend outward to distances as great as 300 m (1000 feet) from the well. The growth rates and lengths of fractures can be tracked with a geophysical technique known as microseismic monitoring, which triangulates fracture locations by detecting the motion of breaking rock with an array of special transducers called “geophones.” The fractures themselves do not have to be especially large to create high-permeability flowpaths for gas in ultra-tight rocks like shale. Laboratory permeability measurements (Soeder 1988) showed that barely-visible hairline cracks were important for gas movement in shale, because in the ultra-tight matrix a hairline crack looks like an eight-lane freeway to a gas molecule.

Short half-life radioactive tracers such as iodine or antimony isotopes are sometimes added to the proppant to allow the height of the hydraulic fractures to be traced in the subsurface (Smith and Montgomery 2015). These tracers are useful in vertical wells, where a wireline gamma log can be employed to detect the top and bottom of the propped fracture. In staged fractures along shale laterals, microseismic monitoring is a more effective technique.

Step 4. Isolating the Stage When a hydraulic fracturing stage is finished, the pressure is released and a seal is set into the production casing to close off the perforated and fractured zone from the rest of the well. In the past the seals were typically bridge plugs made of solid cement or a composite material that had to be drilled out to open up the well after completion. Newer designs use a donut-like rubber cylinder called a packer that is equipped with a check valve. The valve blocks the downhole direction to keep frack pressure in the stage being treated from entering the previously fracked stage. When the well begins production, fluid and gas flow is in the uphole direction, and the check valves open.

Step 5. Moving to the Next Stage The perf gun is reloaded and lowered back into the well, and another set of perforations is shot into the next stage of production tubing. The hydraulic fracture treatment is repeated on this interval, which is then closed off with another bridge plug or packer. The process continues stage by stage until reaching the heel. Depending on the size of each stage, the number of stages per lateral, and the number of wells requiring stimulation on a single pad, the typical hydraulic fracturing job usually takes about 2 weeks to a month to complete for each well pad location.

Step 6. Flowback and Production Shale gas is commonly “overpressured,” which means that the initial gas pressure in the rock is greater than the hydrostatic pressure gradient. Thus, the gas pressure is able to push the frack fluid back up and out of the well. The operator does this with the intent of expelling as much liquid as possible, diverting it into a holding tank or pond through a pipe called the “blooey line.” The initial returned fluid, known as “flowback” is made up of discontinuous phases of gas, water, and sometimes petroleum. Since the well is not on production yet, the fluids must be stored onsite, and storage of gas is always a problem. The blooey line is usually fitted with a flare bucket, generally a metal can filled with burning, dieselsoaked rags hung on the end of the pipe to ignite or “flare” any gas. Flaring is only allowed for short time periods under revisions to the U.S. Clean Air Act, and by many state regulators.

Flowback typically consists of the frack fluids pumped downhole to break the rock, plus some percentage of water from the formation. It starts out relatively fresh with just frack fluids, but becomes increasingly salty over time (Hayes 2009). The origin of the high total dissolved solids (TDS) content of these waters, which can be six to ten times saltier than seawater is not well understood. Shale was deposited on the seafloor, and thus it does contain connate saltwater in the pores, but this water phase is almost never mobile (Soeder 1988). USGS studies indicate that the TDS in the produced water was already in solution downhole, and did not come from solid mineral crystals in the shale being dissolved out by the frack fluid (Engle et al. 2011). Current thinking is that the produced brines in shale wells are a remnant mobile water phase from the introduced frack fluid that has grown salty by reaching osmotic equilibrium with very saline connate water in the shale pores. This would explain the increase in salinity over time, and the marginal mobility of the liquid. Brines produced from oil and gas wells must be properly disposed of using Class II Underground Injection Control (UIC) wells.

People originally labeled the returned fresh water used in the frack as “flowback,” and called the saltier water from the formation “produced water.” However, flowback has acquired a regulatory meaning with a number of state agencies, and some authors now use produced water as a more generic term for all non-hydrocarbon liquids that come out of the well. Oilfield brine is also sometimes used as a descriptor. It is important to be aware of these conventions when reading the literature.

Some operators filter out suspended solids and recycle the recovered water into another frack to reduce the waste volume and minimize the costs of disposal. This requires a degree of logistics to be effective, and is only economical on certain shale plays like the Marcellus where active development can readily use the water. On other plays like the Bakken, the water is used only once before disposal. The water slated for disposal is classified as “residual waste,” a term used for waste produced by industrial processes, to distinguish it from municipal waste. The most common method for disposal of residual waste is by injection down UIC wells (Maloney and Yoxtheimer 2012). However, everything has consequences. Disposing of wastewater down UIC wells can pressurize existing deep faults, causing them to “unlock” and create earthquakes.

It is important to note that residual waste is not the same as hazardous waste. Hazardous wastes are regulated under Subtitle C of the U.S. Resource Conservation and Recovery Act (RCRA), while residual wastes are managed by state authorities under approved waste plans. Oil and gas exploration and production wastes are considered natural materials that are exempted from the definition of hazardous waste. The U.S. Environmental Protection Agency (EPA) has published guidance encouraging operators to manage these wastes appropriately (USEPA 2020).

Almost all O&G wells produce some water or brine along with the hydrocarbons. A common humorous saying in the industry is they operate water wells

Fig. 2.6 A post-completion, production wellhead known as a "Christmas tree" installed on a shale gas well in Pennsylvania. (Photographed in 2012 by Dan Soeder)

that produce a little bit of oil and gas. The ratio of this water to the total produced fluids from the well is called the "water cut" and it can change over the course of production. If the water cut gets too high for the well to remain profitable, it is said to have "watered out" and is shut in or plugged. The economics would improve if a beneficial use like crop irrigation could be found for produced water. Produced waters with low salinity have been used for irrigation in California and Wyoming. However, most produced water needs the high levels of TDS reduced before any large-scale use.

Dealing with produced water in a responsible manner is a major technical and economic issue for the O&G industry that includes both conventional and unconventional production. Some states allow surface disposal, usually by evaporation. This is more prevalent in the west where the drier air and hotter sun speeds up the process. Once the water evaporates off, the residual minerals that remain behind can be disposed of as solid waste. Other states require industrial wastewater treatment to reduce the TDS content of the produced water prior to surface disposal. This is an expensive process, and is largely avoided by the use of UIC wells.

Once gas production starts, the frack gate is replaced by a much less massive production wellhead called the Christmas tree (Fig. 2.6). The outflow line from the Christmas tree goes through a gas-water separator, which is a tall, narrow tank with an outlet at the bottom for water and one at the top for gas to separate the two fluids using gravity.

Water in gas pipelines must be avoided—under high pressures and low temperatures in the presence of natural gas, it will form a solid, ice-like compound called methane hydrate. Methane hydrates are known as "clathrates" and incorporate methane molecules as part of the crystal lattice structure (Collett et al. 2009). They occur naturally in cold, high-pressure environments like the bottom of the deep ocean or under Arctic permafrost. In a high-pressure gas transmission pipeline, it may completely block the pipe and will not endear the well operator to the pipeline company. The gas is processed through ethylene glycol dryers to remove any remaining traces of water vapor before it goes into a gas transmission pipeline.

2.4 Frack Chemicals

The components of hydraulic fracturing fluid consist mostly of fresh water, proppant sand, and a fraction of a percent of chemical additives (Fig. 2.7). Although the chemicals are used in low concentrations, they are deployed at the drill site in large volumes. This is because the water, chemical, and sand mix is blended during the progress of the frack, where the types and amounts of chemicals added may change over the course of the stimulation.

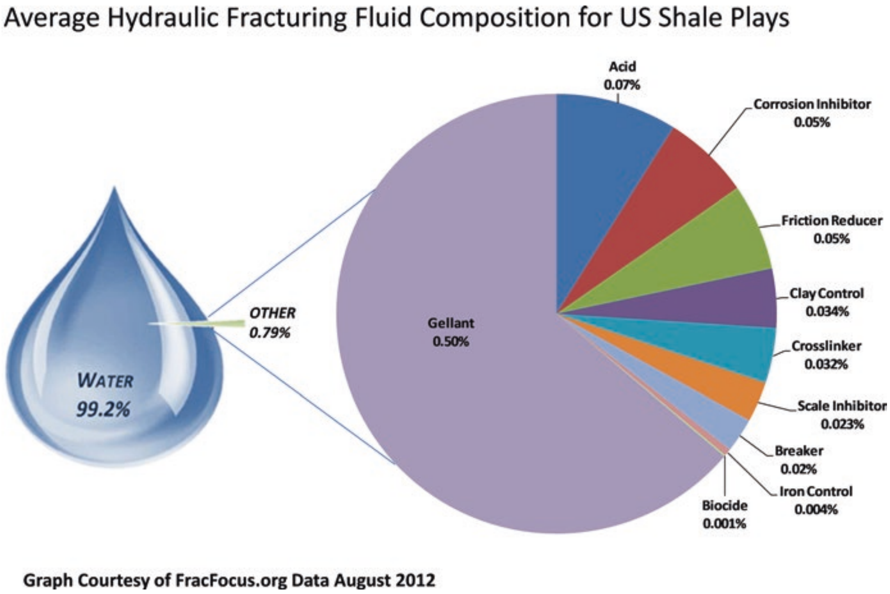


Fig. 2.7 The components of hydraulic fracturing fluid; chemical additives are less than 1% of the total. (Source: Adapted from FracFocus webpages)

The most common frack fluid chemical additives are methanol, isopropanol, crystalline silica, 2-butoxyethanol, ethylene glycol, hydrotreated petroleum distillates, sodium hydroxide, hydrochloric acid, ammonium chloride, ammonium and sodium persulfate, glutaraldehyde, and polyacrylamide (Soeder et al. 2014). The additives serve to clean perforations, reduce friction losses, provide corrosion resistance, inhibit scale build-up, and suppress microbes.

The EPA compiled a consolidated list of over 930 chemical compounds used or found in hydraulic fracturing, including 132 chemicals present in produced waters (USEPA 2016). Sources included federal and state government documents, industry-provided data, and other reliable information. Listings of frack additives on a well-by-well basis are also posted on the FracFocus website (http://fracfocus.org/), a cooperative venture between the Ground Water Protection Council and Interstate Oil and Gas Compact Commission. The information is posted voluntarily by service companies in some cases, and it is required by state permit in others.

The claim that “hundreds” of chemicals are added to frack fluid is a misunderstanding. While a great many chemicals have been tried over the history of hydraulic fracturing, no service company adds hundreds or even dozens of chemicals to any individual frack. Different chemicals may be used in different stages, but advances in hydraulic fracturing technology have reduced the total number of chemicals used to less than half a dozen in a single frack stage (Soeder et al. 2014). Many of the chemicals present in groundwater that people blame on hydraulic fracturing are actually coming from elsewhere (McMahon et al. 2015, 2016, 2017, 2019).

There are a number of concerns about chemical additives to fracks. Many of these compounds are new, and little is known about how they will react in the environment. Most of the formulations are proprietary trade secrets, so information about what is being added and in what quantities is not readily available to researchers. Although many of the additives are posted on the FracFocus website, the descriptions are often vague and generic.

The process by which an organic chemical breaks down over time in the environment is called natural attenuation (NA), and knowing the individual steps, daughter products, and reaction rates is important for remediating a contamination event. NA information currently exists for things like hydrocarbon fuels, chlorinated solvents and other organic compounds, but it is very sparse for the chemical additives to hydraulic fracturing fluid. The response to a spill or a leak of frack chemicals would be problematic at best with the current lack of understanding about how they behave in the environment. This will be explored further in coming chapters.

One other frack additive that has some issues is sand. Hydraulic fracturing in shale requires less proppant than other kinds of fracks because “asperities” or natural rough spots are created on fracture walls that help prop open the fractures when pressure is released. However, because of the high volume of hydraulic fracturing in shale, even these so-called “light sand” fracks end up requiring a lot of proppant. To work well as a proppant, the sand must be composed of evenly-sized, well-rounded quartz grains with a high compressive strength.

The Jordan Sandstone in Wisconsin is one of the few formations in the U.S. that consistently meets the standards for frack sand. Concerns have been raised by the state geological survey about the damage to landscapes resulting from the extensive mining of this sand for fracking (Parsen and Zambito 2014). Manufactured ceramic proppants are available as substitutes, but their cost is usually significantly higher than natural sand. Most service companies only use the manufactured material in special circumstances.

References

Ahmed, U., Abou-Sayed, A. S., Buchholdt, L. M., Jones, A. H., & Kozik, H. G. (1979). *Massive hydraulic fracture containment and productivity analyses of MEC Muse-Duke well #1*. Report prepared by Terra Tek and Mitchell Energy Corporation for the U.S. Department of Energy under Contract No. EG-78-C-08-1547, Morgantown, WV, 21 p.

Charpentier, R. R., & Cook, T. A. (2011). *USGS methodology for assessing continuous petroleum resources*. U.S. Geological Survey Open File Report 2011–1167, 75 p.

Civan, F., & Devegowda, D. (2015). *Comparison of shale permeability to gas determined by pressure pulse transmission testing of core plugs and crushed samples: Paper 2154049*. In Proceedings of Unconventional Resources Technology Conference (URTeC), San Antonio, TX, 20–22 July 2015. https://doi.org/10.15530/urtec-2015-2154049, 11 p.

Collett, T. S., Johnson, A. H., Knapp, C. C., & Boswell, R. (2009). Natural gas hydrates: A review. In T. Collett, A. Johnson, C. Knapp, & R. Boswell (Eds.), *Natural gas hydrates--energy resource potential and associated geologic hazards* (AAPG Memoir 89) (pp. 146–219). Tulsa, OK: American Association of Petroleum Geologists.

Economides, M. J., & Nolte, K. G. (Eds.). (2000). *Reservoir stimulation* (3rd ed.). Chichester, UK, Wiley: 856 p.

Engle, M. A., Rowan, E. L., Kraemer, T. F., & Doolan, C. (2011). *Marcellus shale flowback waters: Examination of solute and water sources*. In American Association of Petroleum Geologists eastern section meeting, September 25–27, Arlington, Virginia, Abstract.

Eschner, K. (2017). A civil war colonel invented fracking in the 1860s. *Smithsonian Magazine*, April 25, 2017. https://www.smithsonianmag.com/smart-news/civil-war-colonel-invented-fracking-1860s-180962979/. Accessed 23 Mar, 2020.

Fisher, K. (2010). Data confirm safety of well fracturing. *The American Oil and Gas Reporter*, July, 2010.

Freeze, R. A., & Cherry, J. A. (1979). *Groundwater*. Englewood Cliffs, NJ: Prentice-Hall. 604 p.

Hayes, T. (2009). *Sampling and analysis of water streams associated with the development of Marcellus shale gas*. Gas Technology Institute, Chicago; final report for Marcellus Shale Coalition, 49 p.

Josh, M., Esteban, L., Delle Piane, C., Sarout, J., Dewhurst, D. N., & Clennell, M. B. (2012). Laboratory characterisation of shale properties. *Journal of Petroleum Science and Engineering, 88-89*, 107–124.

Loucks, R. G., Reed, R. M., Ruppel, S. C., & Hammes, H. (2012). Spectrum of pore types and networks in mudrocks and a descriptive classification for matrix-related mudrock pores. *American Association of Petroleum Geologists Bulletin, 96*, 1071–1098.

Maloney, K. O., & Yoxtheimer, D. A. (2012). Production and disposal of waste materials from gas and oil extraction from the Marcellus shale play in Pennsylvania. *Environmental Practice, 14*, 278–287.

McMahon, P. B., Caldwell, R. R., Galloway, J. M., Valder, J. F., & Hunt, A. G. (2015). Quality and age of shallow groundwater in the Bakken formation production area, Williston basin, Montana and North Dakota. *Groundwater, 53*, 81–94.

McMahon, P. B., Kulongoski, J. T., Wright, M. T., Land, M. T., Landon, M. K., Cozzarelli, I. M., Vengosh, A., & Aiken, G. R. (2016). *Preliminary results from exploratory sampling of wells for* *the California oil, gas, and groundwater program, 2014-15*. U.S. Geological Survey Open-File Report 2016-1100, 8 p. https://doi.org/10.3133/ofr20161100.

McMahon, P. B., Barlow, J. R. B., Engle, M. A., Belitz, K., Ging, P. B., Hunt, A. G., Jurgens, B. C., Kharaka, Y. K., Tollett, R. W., & Kresse, T. M. (2017). Methane and benzene in drinking-water wells overlying the Eagle Ford, Fayetteville, and Haynesville shale hydrocarbon production areas. *Environmental Science & Technology, 51*(12), 6727–6734.

McMahon, P. B., Lindsey, B. D., Conlon, M. D., Hunt, A. G., Belitz, K., Jurgens, B. C., & Varela, B. A. (2019). Hydrocarbons in upland groundwater, Marcellus shale region, northeastern Pennsylvania and southern New York, USA. *Environmental Science & Technology*, Online Publication Date: 27 June 2019. https://doi.org/10.1021/acs.est.9b01440

Montgomery, C. T., & Smith, M. B. (2010). Hydraulic fracturing: History of an enduring technology. *Journal of Petroleum Technology, 62*(12), 26–32.

Parsen, M., & Zambito, J. (2014). *Frac sand in Wisconsin: Fact sheet 05*, Wisconsin Geological and Natural History Survey, Madison, WI, 2 p. http://wgnhs.uwex.edu/pubs/fs05/

Randolph, P. L. (1983). *Porosity and permeability of Mesaverde core from the U.S. DOE multiwell experiment, Garfield County, Colorado*. In Proceedings, 1983 SPE/DOE Joint Symposium on Low Permeability Gas Reservoirs, Denver, Colorado, March 13–16, paper SPE/DOE 11765.

Rodriguez, R., Crandall, D., Song, X., Verba, C., & Soeder, D. (2014). *Imaging techniques for Analyzing shale pores and minerals* (Report NETL-TRS-6-2014; NETL technical report series). Morgantown, WV: U.S. Department of Energy, National Energy Technology Laboratory. 40 p.

Schrider, L. A., & Wise, R. L. (1980, April). Potential new sources of natural gas. *Journal of Petroleum Technology*, 703–716.

Smith, M. B., & Montgomery, C. (2015). *Hydraulic fracturing* (812 p). Boca Raton: CRC Press.

Soeder, D. J. (1988). Porosity and permeability of eastern Devonian gas shale. *SPE Formation Evaluation, 3*(1), 116–124. https://doi.org/10.2118/15213-PA.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Kappel, W. M. (2009). *Water resources and natural gas production from the Marcellus shale*. U.S. Geological Survey, Fact Sheet 2009–3032, 6 p.

Soeder, D. J., Sharma, S., Pekney, N., Hopkinson, L., Dilmore, R., Kutchko, B., Stewart, B., Carter, K., Hakala, A., & Capo, R. (2014). An approach for assessing engineering risk from shale gas wells in the United States. *International Journal of Coal Geology, 126*, 4–19.

USEPA. (2016). *Hydraulic fracturing for oil and gas: Impacts from the hydraulic fracturing water cycle on drinking water resources in the United States (Final Report): EPA/600/R-16/236F*, Washington, DC, 664 p.

USEPA. (2020). *Summary of input on oil and gas extraction wastewater management practices under the Clean Water Act, Final report: EPA-821-S19-001*. U.S. Environmental Protection Agency, Engineering and Analysis Division, Office of Water, Washington, DC, 33 p.

Chapter 3
The History of Oil & Gas Development in the U.S.

In order to understand why there is fracking, it is important to understand the historical context of the technology. Fracking, at its most basic, is nothing more than a specialized reservoir stimulation method to engineer high-permeability flow-paths into an underground body of rock so the hydrocarbons can flow to a well and be produced. So why was fracking needed?

Natural resources are usually produced by starting with whatever is easiest and cheapest to extract. As those "high grade" resources get used up, producing the remaining resource becomes increasingly difficult and costly, although there is generally a lot more of it (Soeder 2012). This distribution is known as the "resource triangle" and it applies to nearly all natural resources, from drinking water to diamonds (Fig. 3.1).

In the United States, most of the "easy" oil and gas resources had been extracted by the 1950s. The American oil industry had three options; (1) go after the more difficult resources offshore or in remote locations like Alaska, (2) import the easy resources from other countries overseas, or (3) try to produce the lower-grade, tighter, and technically-challenging resources remaining in the lower 48. The industry was focused on the first two options from the 1960s to the 1990s, until fracking technology matured enough to allow the third.

Petroleum has a history that pre-dates the Industrial Revolution by centuries. Crude oil and bitumen were gathered from natural seeps thousands of years ago in Mesopotamia by the Sumerians, Assyrians, and Babylonians, who used it for architecture, road construction, waterproofing ships, and medicines. The Romans were aware of rock oil and bitumen, and it was described by scholars like Pliny. However, the Romans had little practical use for oil and regarded petroleum only as a curiosity (Giddens 1938). The Chinese had an active petroleum production and distribution industry as long ago as 100 B.C. (Harper 1998).

In the ninth century A.D., a Persian physician called Ibn Sina (c.980–1037) described the medicinal uses of petroleum in his influential encyclopedia of medicine (McDonald 2011). These included various concoctions for eye diseases, reptile

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_3

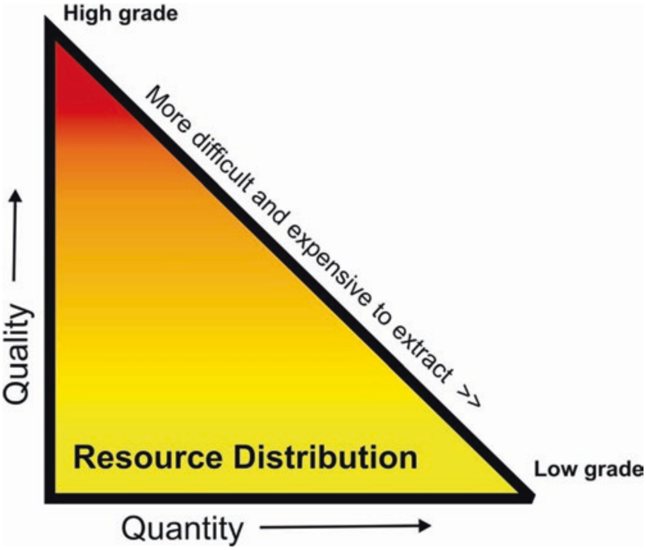


Fig. 3.1 Distribution triangle for most natural resources. (Original sketch by Dan Soeder)

bites, respiratory problems, hysteria, epilepsy, uterine prolapse, and bringing on menstruation. Petroleum mixed with the ashes of cabbage stalks was said to be good for scabies. A preparation of petroleum applied to the forehead was prescribed to warm the brain.

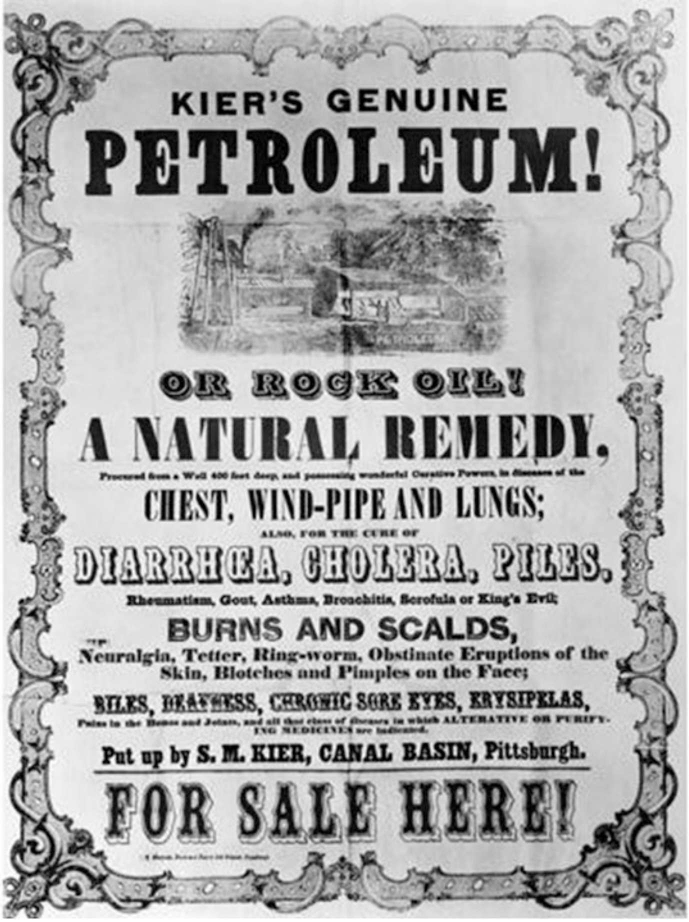
The subsequent translation of Ibn Sina's medical encyclopedia into Latin spread the knowledge to Europe, where it reached Constantinus Africanus (c.1020–1087), the first Latin scholar to use the word "petroleum" to describe liquid fossil fuel hydrocarbons (McDonald 2011). The term itself is apparently a Latinization of a Byzantine Greek word that literally means "rock oil," which is indeed a straightforward description of the substance.

In North America, the Seneca tribe of the Iroquois Nation had been collecting oil from natural seeps for hundreds of years, employing it as a salve, insect repellent, and cure-all tonic. Early European settlers in the 1600s called the black, gooey substance "Seneca Oil," and followed the example of the natives by using it as a medicine (Harper 1995). By the mid-nineteenth century, rock oil obtained primarily from surface seeps was being marketed by numerous and often shady entrepreneurs as a medical treatment for everything from ulcers to blindness.

One of the more famous of these petroleum-based patent medicines at the time was a product sold by a man named Samuel M. Kier in Pennsylvania. Kier was in the business of supplying salt to Pennsylvania farmers, who needed it to cure meat, pickle vegetables, and keep livestock healthy. Pennsylvania is a long way from the ocean, the source of salt in coastal regions, so Kier and his father operated a number of saltwater wells near Tarentum along the Allegheny River, producing brines from various sedimentary rocks at depths of up to 500 feet. They would evaporate the brines to create rock salt. Substantial amounts of crude oil also came up with the saltwater, which annoyingly had to be separated out and discarded (Brice 2008).

In 1848, Samuel Kier's wife (or by some accounts, the wife of a friend) developed tuberculosis. The doctor prescribed "American Medicinal Oil" as a cure, which was produced as a byproduct from a brine well in Kentucky (Miller 1974). The woman's health apparently improved, and Kier quickly realized that this so-called medicinal oil was essentially the same material he had been disposing of for years as a contaminant in his saltwater wells.

Kier decided to market the oil recovered from his wells as a stand-alone product, and in 1852 he launched "Kier's Genuine Petroleum, or Rock Oil" as a cure-all (Fig. 3.2). Like many patent medicines of the time, it boasted wildly preposterous claims of "clearing the chest, wind-pipe and lungs," along with curing diarrhea,



KIER'S GENUINE
PETROLEUM!
OR ROCK OIL!
A NATURAL REMEDY,
Procured from a Well 400 feet deep, and possessing wonderful Curative Powers, in diseases of the
CHEST, WIND-PIPE AND LUNGS;
ALSO, FOR THE CURE OF
DIARRHŒA, CHOLERA, PILES,
Rheumatism, Gout, Asthma, Bronchitis, Scrofula or King's Evil;
BURNS AND SCALDS,
Neuralgia, Tetter, Ring-worm, Obstinate Eruptions of the Skin, Blotches and Pimples on the Face;
BILES, DEAFNESS, CHRONIC SORE EYES, ERYSIPELAS,
Pains in the Bones and Joints, and all that class of diseases in which ALTERATIVE OR PURIFYING MEDICINES are indicated.
Put up by S. M. KIER, CANAL BASIN, Pittsburgh.
FOR SALE HERE!

Fig. 3.2 Advertisement from the 1850s for Kier's Genuine Petroleum as a patent medicine that supposedly cured nearly everything. (Source: Pennsylvania Historical and Museum Commission, Drake Well Museum) cholera, piles, rheumatism, gout, asthma, bronchitis, burns and scalds, neuralgia, ringworm, skin eruptions, deafness, chronic sore eyes, and several other things.

Despite the P.T. Barnum "medicine show" approach of Kier and many other nineteenth century oil pitchmen, petroleum actually did have some value as a medicine, and it is still used today in the form of petroleum jelly, an effective ointment and salve. Another significant use of rock oil for modern medicine is somewhat more indirect. It supplies many of the raw materials needed as chemical feedstocks by the pharmaceutical industry.

Because of his excessive marketing expenses, Kier wasn't making much money on his medicinal petroleum, so he decided to look for other uses. He discovered, perhaps accidentally, that rock oil could be burned, and he considered selling it as a lamp oil. However, crude oil was unappealing for use in people's houses because it produced an unpleasant odor and heavy black smoke when burned. Until these problems could be resolved in some manner, no one would buy it as a lamp fuel (Brice 2008).

3.1 Saving the Whales

The primary type of oil used for indoor lamp illumination in the mid-nineteenth century was whale oil, which burned cleanly and brightly. However, as sperm whales in the Atlantic Ocean were hunted nearly to extinction for their oil, it became increasingly rare and more expensive, commanding prices (in 1850s dollars) as high as $100 per barrel in the U.S. (Harper 1998). Whale hunting was romanticized by Melville in the novel Moby Dick, published in 1851.

A decade earlier, scientists in Europe had begun experimenting with methods for making oil from coal to ease their own dependence on whale oil for illumination. Dr. Abraham Gesner, a Canadian geologist in New Brunswick, made the first successful "coal oil" in North America from bitumen (Ginsberg 2009). Bitumen (also known as asphalt) is a heavy crude oil composed of a viscous mixture of long chain hydrocarbons. It commonly forms as a residual deposit in natural oil seeps after the lighter hydrocarbons have evaporated off (Fig. 3.3). Dr. Gesner had essentially refined crude oil into a clean-burning liquid he called "keroselain" from the Greek words for "wax" and "oil." It soon became widely known as kerosene.

Samuel Kier became aware that a process existed for refining crude oil into kerosene, and he realized that kerosene would be an excellent lamp oil. Not knowing how to make it, he contacted a chemist named James C. Booth in Philadelphia. Booth sent Kier some drawings of an apparatus that would be capable of safely performing the distillation of crude oil into purer, lighter products. In the early 1850s, Kier began to produce what he called "Carbon Oil" for use as a fuel in lamps (Brice 2008).

Unfortunately, there were no oil lamps in existence at the time that could utilize Kier's Carbon Oil as a fuel. Undaunted, he developed a lantern that would burn his refined kerosene oil through the use of an adjustable wick to transport the fuel to a

Fig. 3.3 A natural oil seep in an otherwise dry gully, Salt Creek Oil Field, Wyoming. (Photographed in 2019 by Dan Soeder)

combustion tube inside a glass chimney where it would burn brightly at a high temperature without producing smoke. This design can still be found in many modern kerosene lanterns, not all sold as nostalgia items.

By 1854, Kier had established first a one-barrel, then a five-barrel crude oil distillery in the city of Pittsburgh on Seventh Avenue near Grant Street to make his Carbon Oil. A historical marker at the site in present-day downtown reads: “Kier Refinery – Using a five-barrel still, Samuel M. Kier erected on this site about 1854 the first commercial refinery to produce illuminating oil from petroleum” (Ginsberg 2009). Kier had a thriving business and a good income selling kerosene and lanterns, but he never bothered to patent any of his inventions and they were developed on a massive scale by others. Instead of becoming a famous multi-millionaire industrialist like J.P. Morgan, Carnegie, or Rockefeller, Samuel M. Kier has been largely forgotten as a pioneer of the petroleum business.

Kerosene from petroleum was substantially cheaper than whale oil, and the popularity of kerosene-fired lamps grew quickly. Demand for whale oil fell to low levels and eventually to zero as people switched fuels to kerosene. Commercial whaling ceased to be an income-producing profession, and it was the whalers that became extinct, rather than the whales. The historical fact that the fledgling petroleum industry was responsible for saving sperm whales from extinction does not sit well with some people, but it is what it is. Subsequent replacement of the kerosene lantern by Thomas Edison's electric light a few decades later caused little harm to the petroleum industry because by then, many other uses for rock oil had been found. In fact, the most prominent use of Dr. Gesner's kerosene product these days is for jet fuel.

The Pennsylvania Rock Oil Company was also producing medicinal petroleum in the mid-nineteenth century in northwestern PA near the town of Titusville in Venango County. Their oil source was collected from natural seeps along a stream aptly named Oil Creek. Two Connecticut businessmen named George Bissell and Jonathan Eveleth had purchased a farm along Oil Creek for $5000 after the farmer, Francis Brewer, sent a sample of oil from the seep to Dartmouth College for analysis (McKithan 1978). Bissell and Eveleth created the Pennsylvania Rock Oil Company as a New York corporation in 1854, transferred the Brewer farm to the company, and began making medicine.

A former conductor for the New York and New Haven Railroad named Edwin Drake had befriended Bissell in New York and invested $200 of his own savings into the Pennsylvania Rock Oil Company. Drake had retired from the railroad for health reasons, but Bissell and Eveleth needed someone to travel into the western Pennsylvania "wilderness" to assess their new oil prospect. As a retired conductor, Drake could ride the rails for free, saving the Pennsylvania Rock Oil Company substantial travel costs (Brice 2009). Bissell and Eveleth persuaded him to travel to Titusville, Pennsylvania in December 1857 and visit the Brewer farm (Harper 1998). Drake reported back that substantial amounts of oil appeared to be recoverable from the site.

It is unclear who actually came up with the idea of drilling a well to produce oil from the ground. At this point, Samuel Kier was actively refining petroleum into kerosene in Pittsburgh and creating new markets for oil, but it is not known if Drake and his partners were aware of this, although many historians suspect they were. The growing kerosene lamp business certainly would have provided the justification for drilling a well instead of just scraping up oil from a seep for medicine. Some stories suggest that George Bissell was seeking shelter under an awning in New York City on a hot summer day, and saw one of Kier's "Rock Oil" flyers in a drug store window that featured the derrick of a brine well (Brice 2009). In any case, Bissell and Eveleth placed Drake in charge of producing petroleum from the Titusville site, and he is credited with developing the idea of drilling for oil.

Seeking to avoid taxes and maximize profits, Bissell and Eveleth, along with some additional investors reorganized the Pennsylvania Rock Oil Company into Seneca Oil Company in 1858 as a New Haven, Connecticut based corporation. Part of their scheme to promote the Oil Creek drilling project included sending mail to the hotel in Titusville addressed to one "Colonel Edwin Drake." Although he had never actually been a military officer, the title stuck and "Colonel Drake" found that it commanded more respect and attention from the locals than plain old "Mr. Drake" would ever have gotten. In 1959 on the centennial of his oil discovery in Titusville, the Pennsylvania State Legislature posthumously appointed Drake as a Colonel in the Pennsylvania National Guard, and his title became official. (Brice 2009).

Unable to find a local driller to take on the project, Drake hired William A. "Uncle Billy" Smith, a salt-well driller and blacksmith from Tarentum, PA (ironically the site of Kier's salt wells) to lead the effort. Uncle Billy constructed an engine house and derrick (Fig. 3.4) on the flat floodplain of Oil Creek in May of 1859 (Brice 2009).

Drake had continuous money problems during the venture. His business partners were stingy with capital and he was constantly short of funds. In fact, after spending only about $2500 on the effort, Drake's financial backers in Connecticut decided to give up on finding oil and ordered him to quit. However, before the cease and desist letter arrived, Drake had taken out a $500 bank loan to keep the operation going (Brice 2009). The loan was co-signed by two local friends, R. D. Fletcher and Peter Wilson of Titusville, and it is Wilson who appears with Drake in the photograph

Fig. 3.4 Colonel Edwin Drake (at right with beard) poses with financial backer Peter Wilson in front of the replacement derrick and engine house constructed at Brewer Farm on Oil Creek, Pennsylvania in 1859. (Source: U.S. Library of Congress public domain photos)

shown in Fig. 3.4. The project became known locally as "Drake's Folly" because no one thought he would ever recover enough oil to offset expenses.

Drake used a 6-horsepower (4.5 kW) horizontal steam engine to ram the drill through the soil until it reached bedrock at a depth of 32 feet (10 m). From the description, this was not a modern rotary drill rig but a vertical percussion rig known as a "cable tool" that essentially pounded a hole down into the ground. (Some of these are still in use today for shallow drilling in the Appalachian basin.)

Drake's major innovation was to install 50 feet (20 m) of cast iron casing in the hole to stabilize it from groundwater infiltration and possible collapse (McKithan 1978). Earlier boreholes had been shored up with wooden planks, but this is the first recorded use of iron pipe. In what was to become a pattern throughout his life, Drake failed to patent the idea, and suffered for it financially when it was widely adopted by others.

Drake and Uncle Billy Smith continued drilling at a rate of about 3 feet (1 m) per day once they penetrated bedrock. On August 27, 1859 the drill reached its maximum depth of 69.5 feet (21.2 m) and Drake was forced to stop. The borehole filled with water overnight. When Uncle Billy visited the next day, he found oil on top of the water at a depth of just 5 inches (13 cm) from the top of the well (McKithan 1978).

The original derrick burned down soon afterward, and Drake was forced to rebuild the structure and drill a replacement well to continue production (the photo in Fig. 3.4 shows the second derrick). The well produced 12–20 barrels (2–3 m^3) of oil per day until 1861. The property was sold in 1864 and the derrick was exhibited in Philadelphia at the 1876 Centennial Exposition. Replicas of the derrick and the engine house have been constructed at the location of the original well in the historical park that is now part of the U.S. National Historic Landmark designation for the site (Harper 1998).

A barrel of oil is equivalent to 42 gallons, or 159 liters. The origins of the oil barrel date back to a nineteenth century watertight container known as a tierce that was used for shipping soap, wine, molasses, butter, and whale oil. Several early American oil producers met in Titusville in August of 1866 and agreed that the 42-gallon tierce would serve as the standard container for shipping crude oil. Their decision was practical – the 42-gallon barrel weighed about 300 pounds (136 kg) when filled with crude oil and was about the maximum size one man could reasonably handle. Bigger casks were unmanageable and smaller containers were less profitable. (Source: https://aoghs.org/transportation/history-of-the-42-gallon-oil-barrel/)

Why is the Drake well credited with being the "first" commercial oil well not only in the United States, but the world? After all, oil had been recovered from brine wells for decades all over the globe. In fact, according to the Canadian Petroleum Hall of Fame, the first successful oil well in North America was drilled at Oil Springs, Ontario by James Miller Williams in 1858, fully a year before Edwin Drake and Uncle Billy Smith drilled the Titusville well. Williams founded the "The Canada Oil Company" and used petroleum from his well to manufacture refined lamp oil. (http://www.canadianpetroleumhalloffame.ca/index.html)

Despite the Canadian claim to fame, the thing that makes the Drake well unique is that it was the first well drilled specifically and deliberately for oil (Harper 1998).

Williams in Canada was actually attempting to drill a water well during a drought in September 1858, and struck free oil instead. Because he had been processing asphalt from nearby seeps into lamp oil, he immediately recognized what he had and began capturing it. The fact that his discovery was unintentional in no way diminishes Williams' status as the founder of the Canadian petroleum industry, for which he was awarded two gold medals by the British Empire.

Drake, on the other hand, was almost a failure. Financial problems threatened several times to shut down his operations, and only the slow delivery of mail back in those days prevented him from receiving the cease and desist order from Seneca Oil in Connecticut until after he had already secured a stopgap bank loan with the help of Fletcher and Wilson (Brice 2009). By the time the letter arrived, Drake had enough funding on hand to complete the well. He ignored Bissell and Eveleth and finished the drilling. The finding of oil vindicated everything he had done, and created a great deal of excitement in the financial centers of New York and Boston. People began to consider investing in petroleum, developing the industry and providing the capital needed to drill many more wells. A boom in oil began in northwestern Pennsylvania once word got out about Drake's success. After the Civil War, things took off in a big way for the oil business.

3.2 Spindletop, Gushers, and the Advent of Big Oil

Colonel Edwin Drake never made much money off oil drilling, or anything else for that matter. He spent most of his life job-hopping and trying to make financial ends meet, holding positions as varied as working on a lake steamer out of Buffalo, farming in Michigan, clerking in a hotel, selling merchandise in a New Haven dry goods store, acting as an express agent for the Boston & Albany Railroad, and finally working as a conductor on the New York & New Haven Railroad prior to becoming an oil well driller (Brice 2009).

After the Titusville well was completed, Seneca Oil quickly shoved Drake aside as the oil boom started. Drake ended up working for several years as a local Justice of the Peace in Titusville and selling oil-leases on the side for additional income while Seneca got in on the boom. In 1863 he moved his family to New York City to try his hand at business.

That turned out to be disastrous. Edwin Drake lost nearly everything in less than a year and his health was failing. In these days before any "social safety nets" existed, the Drakes fell on very hard times and got by only with the support of friends. Peter Wilson raised some funds for the family in Titusville from people who were grateful for all the wealth that the ensuing oil boom had brought to the town. However, by 1870 the 50-year old Drake was so incapacitated with what was called "muscular neuralgia"that he could barely get around. Neuralgia is a type of nerve pain that can have many causes, including shingles and diabetes.

Recognizing that he was unable to work and had a family to support, the Pennsylvania State Legislature cleared their consciences in 1873 by granting Drake and his wife an annuity of $1500 per year for the duration of their lives. The wording of the Act noted that Drake was responsible for the "discovery of large quantities of petroleum in this Commonwealth which has greatly stimulated various industries and has also added directly to the revenues of the Commonwealth more than one million dollars since the discovery and which also continues to yield directly to the said revenues a large sum annually." The stipend of $125 a month is paltry by today's standards, but it was actually possible to live on this in the late 1800s. Still, considering the amount of money that Drake's discovery added to state tax coffers, it is more than a bit stingy. Edwin Drake died on November 8, 1880 at the age of 61 (Brice 2009).

As noted in the citation by the state legislature, the Titusville well touched off an explosion of activity in northwestern Pennsylvania that became the first oil boom in the history of humanity. This was followed soon afterward by drilling at other Appalachian sites, where oil seeps were present at the surface, or where brine drillers had found oil in their salt wells. The Appalachian basin was the leading oil-producing region in the United States through 1904.

The oil rush began in the valley of Oil Creek where Drake had drilled the first Seneca Oil well. Titusville became a boomtown, and other towns such as Oil City and Pithole sprang up out of nowhere. By 1866, the Reverend S. J. M. Eaton observed that the population in Oil Creek valley was so dense that it was impossible to distinguish the borders of one town from another (Black 1998).

The population of Titusville grew from 250 residents in 1860 to more than 10,000 by 1865. Ironworks were constructed to supply drilling tools, and eight oil refineries were built between 1862 and 1868. The four log-cabin farmhouses making up the settlement of Pithole became a bustling city with over 50 hotels within just 5 months in 1865 (Hildegarde 1959). As unbelievable as this may seem, similar oil booms have happened in more recent times, most notably the Bakken Shale boom in North Dakota between 2006 and 2015 when the population of small towns such as Watson City increased from 1500 to 15,000 in less than five years (Soeder and Borglum 2019). Natural resource booms from gold rushes to oil rushes seem to be a part of the human condition, and are likely to continue as long as people discover new resources. Future booms on the moon, Mars, and in the asteroid belt will be high-tech versions of Titusville.

The production of U.S. domestic crude oil started at around 2000 barrels (320 m^3) per year in 1859, when Drake's well was drilled. Ten years later, annual production was up to four million barrels (640,000 m^3), and reached ten million barrels (1.6 million m^3) by 1873 (Toyoda 2003). This expansion was driven in a large part by the ongoing industrial development of Europe. In the mid-1860s, U.S. manufacturing capacity was tiny and the primary domestic market for U.S. petroleum was "illumination oil." Europe, on the other hand, was moving full steam ahead into the Industrial Revolution, and British factories in particular were importing large quantities of cheap American oil as fuel and lubricants. During the peak of this first oil boom, Pennsylvania wells were producing one third of the world's oil (Giddens 1938).

In the mid to late nineteenth century, getting the oil out of northwestern Pennsylvania and to markets was no small challenge. Operators at first tried floating it in small barges or skiffs down Oil Creek to the Allegheny River and eventually to Pittsburgh. This turned out to be highly inefficient because nearly a third of the 700–800 barrels of oil loaded into a skiff leaked out before the vessel was even launched, and another third was lost by the time the boats reached Pittsburgh, if they reached Pittsburgh at all. Only a little more than half of the flimsy vessels survived the trip (Black 1998). A railroad line was run into Titusville in 1862 by the Oil Creek Railroad Company, which connected Titusville to several other existing railroads (Hildegarde 1959). The new railroad brought more people into the Oil Creek region and provided a safer alternative to the transport of crude oil. Pipelines were laid from the wells to the rail line in 1865, further improving both the economics and safety of moving oil.

Early products derived from petroleum included expected materials like kerosene lamp fuel and lubricating oils, but a number of unusual byproducts were also developed, in many cases almost by accident. The inventor's maxim of being in the right place at the right time was certainly important, along with critical thinking. For example, the so-called "Pennsylvania-grade" crude oil obtained from wells in the Appalachian basin is often paraffinic or waxy. While this tends to make it a great lubricant, operators were unhappy with wellheads becoming clogged by what was called "sucker rod wax," and it frequently drew the curses of workers who had to halt production to scrape it off. About the only useful thing anyone could say about this gooey material was that it made a pretty good first aid ointment for the treatment of abrasions, burns, and other wounds that routinely afflicted oilfield personnel.

The website of the American Oil & Gas Historical Society (https://aoghs.org/ accessed 8/15/2019) describes a visit to the Titusville oilfields of a young chemist from New York City named Robert Chesebrough. Arriving with plans to drill a gusher and strike it rich, he soon returned to New York more sober and wiser, and he carried samples of the troublesome sucker-rod wax. Fascinated with its reported healing properties, Chesebrough worked in his laboratory to purify the wax and turn the paraffin into a skin balm. In August of 1865 he filed the first of several patents "for purifying petroleum or coal oils by filtration" and he called the resulting product "petroleum jelly." Chesebrough continued to work with the substance and by 1872 he had developed it into a commercial skin care product known as "Vaseline." Although designed for treating cuts and bruises, enterprising consumers soon found that it would also remove stains from furniture, polish wood surfaces, restore leather, and prevent rust. French bakers even added Vaseline to cakes and pastries because it never became rancid like lard or butter. Chesebrough himself was convinced of the health benefits of Vaseline and consumed a spoonful every day, living to the age of 96.

Petroleum jelly became popular among young ladies as a makeup base, and they soon discovered that mixing in a small amount of coal dust or lamp black made a primitive type of mascara for lengthening eyelashes. In 1913, a Miss Mabel Williams of Chicago was carrying out this particular task in preparation for a date while her brother Thomas Lyle Williams watched in fascination. Inspired by Mabel's example, Thomas developed a Vaseline-based mascara that performed better and began selling it by mail order under the name "Lash-brow-ine." By 1917, the mail order sales had brought in enough money to allow Thomas Williams to establish a cosmetics factory in Chicago, which he named Maybell Laboratories in honor of his sister. Williams also gave his Vaseline-based mascara and cosmetic products the new and much more memorable name “Maybelline.” The creation of similar unexpected byproducts from the petroleum industry continues into the present, with the most recognizable example being plastics.

The oil rush in northwestern Pennsylvania resulted in wide swings in petroleum prices during the first decade of oil production. Within 2 years of the completion of Drake’s well, the proliferation of production from Oil Creek valley caused the price of oil to drop from $10 a barrel to 10 cents a barrel (Hildegarde 1959). Producers banded together in 1861 to create the Oil Creek Association in an attempt to restrict output and maintain a price of at least $4 a barrel. They were possibly the world’s first oil cartel.

Oil economics are driven almost purely by supply and demand. When demand is high and the supply low, prices go up. This marks the beginning of a boom cycle as people rush in to capitalize on the high prices. In short order, the frenzy of production activity causes the supply to greatly exceed demand, and prices drop. Wells are shut in, people lose their jobs and production falls in a bust. This drop in production then reduces the supply, and with demand continuing, shortages soon develop and prices climb again. The economics are of course more complicated than this simple example, but the boom and bust nature of the oil and gas business has existed since the beginning. People who work in the industry have an understanding of the cycle and generally possess a gallows sense of humor about it. Typical joke: “What do you call a geologist in Houston during an oil bust? Hey, waiter!”

As oil production was peaking in Pennsylvania in the 1880s, natural gas began to be produced in Ohio and Indiana. Most of the gas used in the nineteenth century for lighting and cooking was a manufactured fuel known as “town gas.” This was made by heating up coal and water in the absence of oxygen. The heat would dissociate the H_2O water molecules into two hydrogen atoms and a single oxygen. The hydrogens would combine to create H_2 or hydrogen gas, and the oxygen would partially combust the carbon in the coal to create CO or carbon monoxide. Both of these gases will burn in air, and the substance was piped into residences and businesses. It is hard to fathom today how folks could have allowed the deadly CO gas into their houses. Those were the days when you could literally put your head in the oven and end it all by taking a few deep breaths. Gas leaks often killed entire families quietly while they slept.

Natural gas is composed of non-toxic methane and is much safer than town gas. Systems for capturing it at a wellhead and transporting it to a customer were in their infancy, however, and drillers often hit gas at pressures they could not contain. Some of the resulting flares were nothing short of spectacular, including the “Karg Well” drilled in 1886 at Findlay, Ohio. The site historical marker states that it produced 12 million cubic feet (340,000 m^3) of gas per day at a pressure that could not be contained and shot a plume of fire a 100 feet (30 m) high for 4 months. The flare was said to be visible from more than 30 miles (48 km) away.

An oil driller named G. Bates is credited with the first discovery of gas in Indiana near the town of Francesville while drilling for oil at a depth of 500 feet (152 m) in 1867 (https://aoghs.org/petroleum-pioneers/indiana-natural-gas-boom/; accessed 8/15/2019). Coal miners in the east-central part of the state were boring a hole in search of coal near the town of Eaton, Indiana in 1876 and discovered gas a depth of about 600 feet (180 m). Not having any way to capture it, they plugged the hole and abandoned the location. A few years later, the 1884 discovery of natural gas near the neighboring town of Findlay in northwestern Ohio prompted additional drilling at Eaton, where a substantial amount of gas was encountered after the original borehole was deepened by an additional 322 feet (98 m). The gas was ignited, and the flame reportedly reached 120 feet (36 m) into the air and was visible from Muncie, Indiana. A gas boom swept the state and thousands of new wells were drilled. This additional drilling revealed that a large gas field was present to the north and east of Indianapolis, and extended into western Ohio. Named the Trenton Field, it was the largest natural gas resource found up to that date. (Glass and Kohrman 2005).

Because no national pipeline distribution system existed for natural gas, the production had to be used locally. Indiana gas supplies soon brought manufacturing industries to the Midwest, including steel makers. Andrew Carnegie said in 1885 that the natural gas he used for making steel replaced 10,000 tons of coal a day, and towns with natural gas resources competed vigorously to attract new businesses. Sadly, much of the gas was wasted, because operators typically flared off a portion of the production at the wellhead in what was known as a “flambeau“to prove to investors that the gas was flowing (Gray 1994).

The Trenton Field also contained substantial amounts of oil associated with the gas, but numerous flambeaus had reduced subsurface pressures to the point where the oil would not flow. Almost all natural gas production from the Trenton Field ended by 1910, with the recovery of only about 10% of the petroleum. An estimated 900 million barrels of oil remained in the field, immobilized by a lack of gas pressure (Gray 1994). High oil prices in the late twentieth century led to the resumption of small amounts of oil production using advanced artificial lift technology.

Oil production in Pennsylvania peaked in 1891, when the state produced 31 million barrels of oil, but it was surpassed by Ohio in 1895. After three decades of dominating petroleum production in the United States, wells in Pennsylvania and Ohio began to slacken off by the turn of the new century, and oil drillers started looking around for other prospects (Williamson et al. 1981). The “Mid-Continent” region became the next area of prolific oil production in the U.S. Encompassing Kansas, Arkansas, Oklahoma, and northern Texas, it includes the Anadarko and Arkoma basins, both of which have been prolific producers. Oil well drilling in Kansas began in 1892, in Texas in 1894, and in Oklahoma in 1897. Oklahoma wasn’t even a state yet, not achieving that status until 1907.

Potential oil resources in the Gulf Coast area of Texas and Louisiana had been routinely dismissed by petroleum prospectors since the days of the Drake well. Despite the presence of sulfur springs and flammable gas seepages, there were few signs of oil at the surface, and the flat topography didn’t appear to contain any of the folded and faulted rocks that drillers had come to associate with the presence of oil. If one could go back in time and purchase a boatload of cheap oil leases, the Texas-Louisiana Gulf Coast would have been the place to do so.

An experienced mining engineer and salt driller named Anthony F. Lucas (born in Croatia as Antun Lucic in 1855) decided to drill a well in 1901 on a 12-foot (3.6 m) high hill south of Beaumont, Texas called Spindletop to see if he could find oil. Lucas suspected that Spindletop Hill might be the surface expression of a salt dome, and reasoned that deformed sediments along the flanks of the dome could contain trapped oil. A self-taught geologist named Patillo Higgins had spent years trying to convince investors to drill for oil on salt domes, but his ideas were met with widespread skepticism. Higgins finally found a believer in Lucas.

Lucas made a lease agreement in 1899 with Higgins, built a derrick and began drilling in October 1900. He ran out of money after drilling to only 575 feet (180 m), and secured additional funds from Pittsburgh oilmen John H. Galey and James M. Guffey (Yergin 1991). On January 10, 1901 the drill bit reached a depth of 1020 feet (311 m) and drilling mud began bubbling out of the hole. Workers fled from the site as the mud flow increased, followed by a chuff of natural gas and then an eruption of oil in a "gusher," which reached a height of more than 150 feet (46 m). The Lucas well had an initial production rate of nearly 100,000 barrels of oil per day, more than all of the other existing oil wells in America combined.

The well spouted oil into the air for 9 days before finally being brought under control. The event continued long enough for a number of local newspaper photographers and even landscape painters to capture images of the gusher (Fig. 3.5), and it remains an enduring symbol from the early days of oil. (https://aoghs.org/petroleum-pioneers/spindletop-launches-modern-oil-industry/; accessed 8/15/2019).

The important thing about Spindletop was not the gusher itself, but how it changed the oil and gas business (Yergin 1991). Oil drillers began to integrate geologic thinking into their strategy. If one salt dome had oil, maybe others did as well. This led to the successful development of other salt dome oilfields, resulting in discoveries at Sour Lake in 1902, Batson in 1904, and Humble in 1905. Oil well engineering also improved, with the development of the "Christmas tree" wellhead to contain downhole pressures, new ideas for balanced drilling by adding barite to drilling mud to increase the weight, and the invention of the blow-out preventer (BOP), a hydraulic ram designed to close off an out-of-control well.

Spindletop led the United States into the oil age (Yergin 1991). The industry realigned itself from producing small amounts of kerosene lantern fuel and lubricants and moved into other markets. The Gulf Coast was recognized as a world-class petroleum province and remains an important hydrocarbon producer today. Oil companies that were created to develop these resources were some of the most significant and innovative to ever exist, although many have disappeared through mergers. Still, names like Gulf Oil, Texaco, Humble, Pure Oil, and others are monuments to the importance of oil and gas recovery from the Gulf Coast. Petroleum became economically feasible as a fuel for mass consumption and could displace coal as the primary energy resource in the United States. It soon became widely used for transportation and electrical generation.

Fig. 3.5 The iconic Lucas gusher in January 1901 at Spindletop Hill, Texas. (Source: Wikimedia Commons public domain; original photo by John Trost)

Spindletop was not the largest oil field in the United States, or even in Texas. The U.S. honor goes to Prudhoe Bay in Alaska, discovered in 1968 with the completion of the Prudhoe Bay State #1 well, drilled by Humble Oil and Atlantic Richfield (ARCO) under the watchful eye of the Alaska Oil and Gas Conservation Commission.

The biggest oilfield in Texas is the East Texas oil field, discovered in 1930 by a colorful character named Columbus Marion Joiner, known in the oilfields as “Dad.” Joiner was born in Alabama and worked as an attorney and state legislator in Tennessee in the late 1800s (White 1968). He got involved in oil drilling after moving to Oklahoma in 1897, where he made and lost two oil fortunes by 1926. Joiner decided to try his luck in Texas, and ignoring prevailing geologic opinions he drilled three wildcat wells in Rusk County using a flimsy rig and battered tools. The first two wells came up dry, but the third well, Daisy Bradford No. 3 was productive and became the discovery well for the East Texas oil field. Since its discovery on October 5, 1930, some 30,340 wells have been drilled within the East Texas oilfield yielding nearly 5.2 billion barrels of oil out of the Cretaceous Eagle Ford-Woodbine group.

Production is from a stratigraphic trap in the Woodbine Sandstone (Dokur and Hentz 2012).

It turned out that the 70 year-old Dad Joiner was essentially a con man trying to sell shares of a mineral lease syndicate to local rustics who fell for his low key, smooth-talking approach. He had drilled the Bradford wells as a prop to impress potential investors, but never actually expected to find anything. Joiner hurriedly sold his well and leases to oil tycoon H.L. Hunt and left Rusk County soon afterward. Nevertheless, he became embroiled in numerous legal proceedings and by 1934 he claimed to have more than 150 lawsuits pending against him (White 1968). Joiner moved to Dallas in 1940 to hide out from his creditors in relative obscurity, but remained beset by financial problems until his death in 1947.

So-called “Big Oil” got started almost as early as the oil industry itself. In what has become a pattern for most American industries from automobiles to electronics to commercial airlines, the initial development of a product or service tends to inspire numerous visionary entrepreneurs who create small companies that often find niche markets for their goods. Once successful, they are then bought out by one of the major players. For example, a man named Charles Pratt started out as a whale oil distributor, but then became an early pioneer of the petroleum industry in the United States. His company was located in Brooklyn, New York, and named Astral Oil Works. Pratt sold kerosene using the exotic slogan, “The holy lamps of Tibet are primed with Astral Oil.” Astral Oil Works was acquired by John D. Rockefeller in 1874 and became a component of the considerably less exotic Standard Oil empire (Chernow 1998).

Rockefeller began his career in 1863 with a refinery in Cleveland, Ohio and became the world’s first “oil baron” in 1865, when he formed the Standard Oil Company with Henry M. Flagler. Flagler is probably better known for spending his share of the Standard Oil fortune to build the “Overseas Railroad” in the early 1900s through the Florida Keys to connect Key West with Miami. Much of this route is now followed by the modern Overseas Highway, U.S. 1.

Business practices were largely unregulated in the late nineteenth century, and Rockefeller reportedly grew his company by engaging in so-called “predatory pricing” practices (Tarbell and Chalmers 1966). These consisted of underpricing the competition, sometimes at a loss, and then buying out competitors at fire sale prices after their businesses failed. The tactics effectively eliminated competition and cornered the market. Standard Oil became the only game in town, charging whatever price the market would bear. By 1880 it was a *de-facto* energy monopoly that had control over the refining of 90–95% of all oil produced in the United States.

In 1882, Rockefeller and his partners re-organized the Standard Oil Company into the Standard Oil Trust, which controlled subsidiary companies under a single, large umbrella organization that included some 40 separate corporations. The idea of a Trust has been attributed to Standard Oil attorney Samuel Dodd (General Records of the United States Government 1890). The nine Trustees appointed the directors and officers of all the subsidiary companies, effectively allowing the Trust to function as a monopoly by exerting complete control over the component companies. All the profits were sent up to the Trustees, who determined the dividends to pay shareholders. By careful design, the inner workings of the Trust and even its very existence were hidden behind a maze of legal maneuvers, corporate figureheads, and paper constructs that made the umbrella organization essentially invisible and impervious to public scrutiny. As one investigative reporter noted at the time, “You could argue its existence from its effects, but you could not prove it” (Tarbell and Chalmers 1966).

Rockefeller claimed only to be seeking efficiencies of scale, and some revisionists have stated there is no real evidence that he built up a monopoly through the practice of predatory pricing (e.g. Armentano 1990). However “efficient” it may have been for the large-scale production and distribution of petroleum products, the excessive concentration of economic power in the Standard Oil Trust was viewed by many Americans with alarm.

The first gasoline-powered, two-cycle internal combustion engine was built in 1870 by a German inventor named Siegfried Marcus, who used it to propel a pushcart. Another German named Nikolaus Otto received a patent in 1886 for the improved four-stroke engine that can still be found under the hood of most modern vehicles. Karl Benz, yet a third German, built a gasoline-powered automobile in 1885, and then proceeded to manufacture and sell several identical copies, thus creating the first “production model” car (Eckermann 2001). Early automobiles were typically hand-crafted one at a time, and remained little more than European curiosities known as “horseless carriages” until the early twentieth century. In 1908, Henry Ford created a car for the “everyman” – the Model T. The factory assembly line was perfected by Ford in 1913, and the Model T Ford became the first mass-produced and affordable automobile. Total sales of the Model T topped 15 million by 1927 (Eckermann 2001), and every single one of them needed gasoline. Gasoline sales in the U.S. exceeded kerosene in 1919 and thereafter.

The nineteenth century business model of the Standard Oil Trust was largely based on the refining and sale of “illumination oil” for lamps. As this market was displaced by Thomas Edison’s electric lighting, Rockefeller and company became increasingly focused on supplying gasoline as fuel for automobiles. The significant mechanization of the military in World War I also showed that oil was a strategic asset required for ships, vehicles, and aircraft. The growing demand for petroleum resulted in the expansion of Standard Oil into oil exploration, production, and transport and it quickly became a multi-armed, corporate behemoth (Chernow 1998).

Business people pay close attention to what others are doing, and Standard Oil was not the only trust for long. The growing problem of trusts caught the attention of Senator John Sherman of Ohio, who at the time was chairman of the Senate Finance Committee (General Records of the United States Government 1890). Sherman proposed a law to authorize the federal government to dissolve trusts based on the constitutional power of Congress to regulate interstate commerce. The Sherman Anti-Trust Act passed the Senate by a vote of 51–1 on April 8, 1890, and the House by a unanimous vote of 242–0 on June 20, 1890. President Benjamin Harrison signed the bill into law on July 2, 1890. Restraint of commerce among states or with foreign nations by means of a trust or monopoly was declared illegal (General Records of the United States Government 1890).

The Sherman Anti-Trust Act was designed to restore competition, but it was loosely worded enough in the definition of critical terms like "trust," "monopoly," and "restraint of commerce" that armies of high-powered lawyers attacked it on the details and weakened it considerably. The ineffective federal anti-trust law led a number of states to try regulating trusts within their boundaries, which typically failed. In a classic example, the Ohio Supreme Court ordered the Standard Oil Trust to be dissolved in 1892. Rockefeller responded by downgrading the Standard Oil Company of Ohio, the host of the Standard Oil Trust, into a smaller subsidiary company known as SOHIO that no longer produced and refined petroleum but only distributed the finished products. The operations of the Trust were transferred to New York City and elsewhere to remove them from the jurisdiction of the Ohio court. Rockefeller and his Trustees then incorporated Standard Oil Company (New Jersey) as a holding company in 1899, moving the assets and interests formerly controlled under the Standard Oil Trust in Ohio to the New Jersey company. The Trust had been taken apart and brazenly reconstituted in another state.

Despite the weaknesses in the Sherman Anti-Trust Act, President Theodore Roosevelt was able to use it successfully in 1904 to dissolve Northern Securities Company in Minnesota as part of his "trust busting" campaign. With a precedent thus being set, President William Howard Taft invoked the Act in 1911 against both the Standard Oil Company and the American Tobacco Company. The Standard Oil Company (New Jersey) was ordered to divest itself of its major holdings—33 companies in all plus the original Standard Oil of New Jersey (Tarbell and Chalmers 1966). No one felt sorry for Rockefeller, however. He still held significant amounts of stock in the resulting 34 newly independent companies, and as the petroleum industry continued to grow, he became wealthier than ever.

Petroleum made John D. Rockefeller the country's first billionaire, and for a time the richest person in the world. After the sudden and unexpected death of wealthy financier J.P. Morgan in 1913, both Rockefeller and his long-time nemesis Andrew Carnegie decided to turn to charitable work to leave a more lasting legacy. The two old rivals soon began competing against each other to see who could give away the most money. Steel magnate Carnegie focused on education and the arts, while Rockefeller became a benefactor of medical science. He created the Rockefeller Foundation in 1913 to fund public health studies and support other charities. He had founded the Rockefeller Institute for Medical Research in 1901, which he expanded. It became Rockefeller University in 1965 (Hanson 2000). Rockefeller eventually won the contest by out-living Carnegie, who died in 1919. Rockefeller survived another 18 years and continued to support charitable work until his death in 1937 at the age of 97.

Despite giving away considerable amounts of money in his later years, Rockefeller's assets at his death were still estimated to be US $1.4 billion, equivalent to 1.5% of the U.S. Gross Domestic Product (GDP) for that year (Hanson 2000). Today that percentage of the GDP would be worth some $32 billion, making him one of the top ten wealthiest people in the nation. Even after all this time, he remains a controversial figure. The young Rockefeller's rapacious capitalism compared to his generous philanthropy in later years led one of his biographers to declare that "his good side was every bit as good as his bad side was bad" (Chernow 1998).

Although the Standard Oil Company and American Tobacco Company trusts were successfully broken apart by President Taft, various industries in the U.S. continue to find the business model developed by attorney Samuel Dodd to be appealing. The Sherman Anti-Trust Act is still on the books, and the federal government last invoked it in 2001 for a ruling against Microsoft Corporation (U.S. Court of Appeals for the District of Columbia Circuit 2001).

John D. Rockefeller wasn't the only nineteenth century oil baron out there. Companies from Great Britain, France, Holland and elsewhere were entering this rapidly-growing market. Because Standard Oil had control of 95% of the oil in the United States, other companies sought petroleum development opportunities elsewhere. Still, the United States had substantial refining capacity, and crude oil was often transported to the U.S. for refining. All of these things helped turn oil into a truly global commodity (Stevens 2013). The founding of the three biggest international petroleum companies, ExxonMobil, Royal Dutch Shell, and BP is described briefly below. These companies are known as "super majors" and represent the face of "Big Oil."

ExxonMobil After the 1911 government-mandated breakup of the Standard Oil Trust, one of the 34 resulting companies was the original Standard Oil (New Jersey), now calling itself Jersey Standard. In 1919, Jersey Standard acquired a 50% interest in Humble Oil & Refining Company of Texas, led by geologist Wallace Pratt. Pratt is famous among geologists for being the first person to use microscopic fossils, primarily foraminifera, to correlate time-equivalent stratigraphic units in the subsurface along the Gulf Coast. Jersey Standard brought out a new gasoline blend in 1926 under the trade name Esso, which few people realized was a simple phonetic rendition of the initials 'S' and 'O' from Standard Oil. The slogan "Put a Tiger in your Tank" was adopted in the 1960s, and Esso became recognized as the corporate brand for the company. In 1972, Jersey Standard held a special shareholders' meeting where an official name change to Exxon Corporation was approved.

On November 30, 1999, Exxon acquired Mobil Oil Corporation, a descendant of the Vacuum Oil Company founded in 1866. Vacuum Oil was one of the early companies snapped up by the Standard Oil Trust, and it was re-established as an independent corporation in the 1911 breakup. It became Mobil Oil Corporation in 1966 on the centennial of its founding. In a press release, the new ExxonMobil Corporation stated that one goal of the merger was simply to improve efficiency (https://corporate.exxonmobil.com/Company/Who-we-are/Our-history; accessed 8/14/19). Somewhere, John D. Rockefeller is smiling.

Royal Dutch Shell In the late nineteenth century, the wealthy Rothschild banking family in France became interested in the production of Russia's oil riches. Russia at the time was a rather backward and poor country, so the Rothschilds commissioned the world's first oil tankers to transport their kerosene out of Russia to more lucrative markets. They engaged British traders Marcus Samuel, Jr. and his brother Sam, who obtained a suitable tanker ship named after a seashell: the Murex. The Samuel brothers formed Shell Transport and Trading in 1897 with the Murex as their flagship, and created the beginnings of a global transportation network for oil.

Oil discoveries in the Dutch East Indies in the late 1800s led to the creation of Royal Dutch Petroleum. The East Indies (now Indonesia) were a Dutch colony very remote from most petroleum markets, and the oil required a robust overseas transportation system. Royal Dutch Petroleum and Shell Transport and Trading combined in 1907 to form the Royal Dutch Shell Group (https://www.shell.com/about-us/our-heritage.html; accessed 8/14/2019). The company is incorporated in the United Kingdom, but headquartered in the Netherlands at The Hague. As an interesting aside, the murex mollusk has an elongated snail shell with long spines and looks a bit frightening. The corporate logo for Royal Dutch Shell (Dutch name: *Koninklijke Nederlandse Petroleum Maatschappij*) uses a much friendlier-looking scallop shell instead.

BP (British Petroleum) In 1901, British financier William Knox D'Arcy was granted a 60-year concession to search for oil and gas in the country of Persia (modern-day Iran). D'Arcy had never been to Persia, so he hired a mining engineer named George Reynolds to supervise drilling operations in the Chiah Surkh mountains, some 350 miles (560 km) west of Tehran. After Reynolds reported that the signs looked promising, D'Arcy formed the First Exploitation Company with a capital of £60,000 to support drilling activities.

Reynolds spent 6 years exploring numerous prospects in Persia and kept coming up empty. He burned through much of D'Arcy's fortune, along with infusions of money from a partner company called Burmah Oil. Reynolds refused to give up, however, and in 1908 he told D'Arcy that a prospect at a place called Masjid-i-Suleiman looked promising. Burmah Oil provided another £40,000 for Reynolds to drill two wells at this new location, but D'Arcy had heard this before. He sent Reynolds a telegram ordering him to quit drilling at 1600 feet if nothing was found. At 4 AM on May 26, 1908 the drill reached 1180 feet and a 25 meter-high fountain of oil spewed up into the sky.

The discovery prompted D'Arcy to issue a prospectus on April 19, 1909 in London and Glasgow for a new company, the Anglo-Persian Oil Company. A pipeline and refinery were constructed in Persia and D'Arcy made back his fortune plus considerably more on top of that (https://www.bp.com/en/global/corporate/who-we-are/our-history.html; accessed 8/14/2019). The wealth of the Anglo-Persian Oil Company improved substantially in ensuing years as petroleum gained popularity in Great Britain just as it had in the United States.

Admiral John Arbuthnot Fisher, who served as the British First Sea Lord between 1904 and 1910 is credited with modernization of the Royal Navy. Among other changes, Fisher mandated that ships be converted from coal to oil. Oil for ship fuel was more efficient because it could be moved about in large quantities by pumps, whereas coal required men to shovel it by hand. It also was easier to carry than coal, and greatly increased the range of ships. When Sir Winston Churchill became First

Lord of the Admiralty in 1911 (at the time, the civilian director of the British Navy), he realized that a secure source of oil was critical for future naval operations. In 1914, Churchill worked out a deal with the Anglo-Persian Oil Company to provide 40 million barrels of oil to the Royal Navy over a period of 20 years in return for a payment of £2 million and 51% British government ownership of the company. The ink was barely dry on the agreement when World War One broke out 6 weeks later.

With the government holding majority ownership interest in the company, the Anglo-Persian Oil Company became British Petroleum. Interestingly, the British Petroleum brand had originally been created by a German oil firm to market its products in England. During the war, the British government seized the German company's assets, and the Public Trustee sold them to Anglo-Persian Oil in 1917. The new British Petroleum obtained an instant distribution network in the U.K. that included 520 depots, 535 railway tank wagons, 1102 road vehicles, four barges, and 650 horses. These days, British Petroleum is known simply as BP.

Along with ExxonMobil, Royal Dutch Shell and BP, two additional corporations round out the top five investor-owned global oil companies (The Economist 2019). These are Chevron USA, a 1977 re-branding of Standard Oil of California, and Total S.A., a French multinational oil and gas company founded in 1924. The Italian multinational company Eni S.p.A., and ConocoPhillips, created in 2002 by the merger of two midsize American oil companies (Conoco Inc. and Phillips Petroleum Co.) are often included in the group for a total of seven "major" oil companies. Some national oil companies, such as PEMEX, PetroBras, Rosneft and others are mostly or wholly-owned by governments and nearly as large in terms of assets and incomes, but are not considered "majors."

The midsize oil companies, some of which can still be pretty big, are called "independents." These include corporations like Marathon, Sinclair, and others. Many of the independents focus on only one aspect of the oil business, such as production, transport, or distribution, known in the O&G industry as "upstream, midstream, and downstream," respectively.

3.3 The Decline of Domestic Production

Oil and gas wells produce the maximum flow of hydrocarbons during the period known as Initial Production or IP. This occurs right after completion of the well, and represents the highest rate of flow the well will ever see. As ongoing production removes hydrocarbons from the ground, downhole pressures drop, stresses on the flowpaths through the rock are increased, and other fluids are able to migrate into the porous reservoir. These factors and others act to reduce the amount of oil and gas flowing into the well over time, and this flow rate drop is called the decline. The behavior of this decline over time in terms of flow rate and drop-off rate can be plotted as a shape known as the "decline curve."

Decline curve analysis (DCA) is a specialized field in petroleum engineering that seeks to determine the return on investment (ROI) from production by using decline curves to forecast the performance of oil and gas wells (Poston and Poe 2008). The production of hydrocarbons declines in different wells at different rates. DCA is a graphical procedure that fits a line through the performance history of a well (i.e. production rate vs. time), and assumes that this same trend will continue into the future. It requires stable production trends to provide reliable results.

Production declines are not linear, or this would be a very simple exercise. The rate at which most wells decline changes over time in a curve, and understanding the shape of the curve is essential to making a prediction. The DCA technique is based on empirical observations of production declines, and the basic assumption is that whatever factors controlled the trend of a curve in the past will continue to govern it in the future in a predictable manner. Three types of decline curves have been identified: exponential, harmonic, and hyperbolic. Exponential decline occurs when the decline rate changes by a constant amount over time. Harmonic decline occurs when the decline rate varies by a predictable amount over time, and hyperbolic decline occurs when the variation in the decline rate is itself variable (Fetkovich et al. 1996). Mathematical equations to define the factors controlling decline curves were developed by Arps (1945) and include things like back pressure, loss of reservoir pressure, changing relative volumes of the produced fluids, and fluid flow through porous media under boundary-dominated conditions.

The decline curves all show that no oil or gas well will produce forever. Most flow for a decade or two, some produce for many decades, and a few have even produced for more than a century. But in the end, they all decline, some gradually and others more abruptly. The concept of "peak oil," described in more detail in Chap. 11 was developed by a Shell geophysicist named M. King Hubbert. He concluded that the amount of petroleum produced from any given oilfield over time followed a bell-shaped curve, peaking as the field was fully developed, and then declining as pressures dropped and the residual oil became an immobile phase and stopped flowing (Hubbert 1956). This meant that new oil reserves would constantly need to be discovered to keep up with demand. If not, the world would run out of oil sooner or later.

The development of oil and gas in the United States during the latter half of the nineteenth century was ahead of most of the rest of the world, and this had a number of consequences with respect to the energy supply a century later. Per capita use of oil and gas in the U.S. began rising steeply with the introduction of the automobile in the 1920s and 30s, and then shot up once restrictions were lifted at the end of the Second World War. Pent-up consumer demand for automobiles, appliances and other goods substantially increased petroleum consumption. Post-war vehicles were designed for comfort and stability, not high fuel mileage.

The construction of better roads and the new interstate highway system gave people more reasons to drive. Institutions that catered to the automobile, such as drive-in restaurants, drive-in theaters, drive-up bank tellers and so forth meant that people used vehicles more often and burned more fuel. People who had migrated from the cities to the suburbs required vehicles to get around, and many families had more than one car. The invention of plastics and other materials derived from petrochemicals placed significant new demands on the petroleum supply.

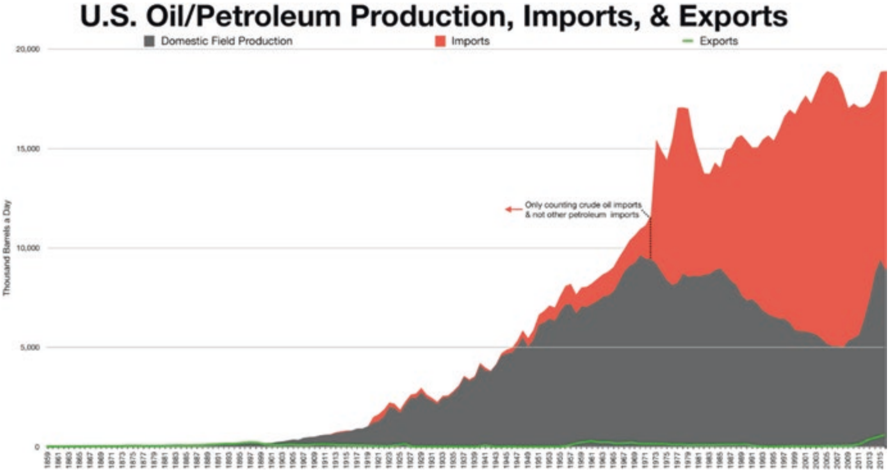


Fig. 3.6 History of U.S. domestic crude oil production, imports, and exports, 1859–2015. (Source: Wikimedia Commons public domain, USEIA webpages and reports)

This upward spike in petroleum demand occurred while conventional oil and gas wells in the U.S. that had been drilled in the 1930s and 40s were in the middle stages of decline. Oil and gas field development continued during the 1950s and 60s, but by then most of the large, onshore fields in the U.S. had already been discovered. Some of the wasteful practices of the past century, such as burning off gas in a flambeau, or allowing a field to depressurize with uncapped gushers were now coming home to roost. A number of small, new fields came online, and operators also began to apply techniques like infill drilling, waterflooding, reservoir re-pressurization, and new types of artificial lift on old fields to get more oil out of the ground.

The majors began to move increasingly into more challenging regions like the Alaska North Slope and deeper waters in the Gulf of Mexico in search of new oilfields. Such ventures were frightfully expensive, and required the discovery of enormous amounts of oil to provide a reasonable ROI. The large quantities of oil that were in fact discovered in these places led to an increase in upstream and midstream environmental risks – as evidenced by the 1989 Exxon Valdez oil spill in Alaska, and the 2010 Deepwater Horizon accident in the Gulf.

The international nature of the major oil companies (driven in part by Standard Oil's lockdown of the American market) sent them to all parts of the planet to obtain crude oil. They refined it at many places around the world, and sold the resulting products on the global market. After the Second World War, the United States became the largest oil-consuming nation on Earth. Driven by this increased demand, oil companies became even more multinational than they had been in the first half of the twentieth century. By 1960, U.S. domestic production was unable to meet demand, and the difference was made up by importing petroleum from overseas. The volume of imported oil continued to increase in the ensuing years (Fig. 3.6) causing the energy supply of the United States to become steadily more dependent on imports. Almost no one at the time thought this mattered. Until it very much did.

References

Armentano, D. T. (1990). *Antitrust and Monopoly: Anatomy of a Policy Failure*. New York: Holmes & Meier. 292 p.

Arps, J. J. (1945). Analysis of decline curves: Paper SPE-945228-G, Society of Petroleum Engineers. *Transactions of the AIME, 160*(1), 228–247.

Black, B. (1998). Oil creek as industrial apparatus: Re-creating the industrial process through the landscape of Pennsylvania's oil boom. *Environmental History, 3*(2), 210–229. https://doi.org/10.2307/3985380.

Brice, W. R. (2008). Samuel M. Kier (1813–1874) – The oft-forgotten oil pioneer. *Oil-Industry History, 9*(1), 73–96.

Brice, W. R. (2009). *Myth, legend, reality: Edwin Laurentine Drake and the early oil industry*. Oil City, PA: Oil Region Alliance of Business, Industry & Tourism. 661 p. (ISBN 10: 0984222200).

Chernow, R. (1998). *Titan: The life of John D. Rockefeller, Sr.* New York: Random House. 750 p.

Dokur, M., & Hentz, T. F. (2012). *Reservoir characterization of the upper cretaceous woodbine Group in Northeast Texas Field, Texas*. AAPG Search and Discovery Article #20152.

Eckermann, E. (2001). *World history of the atomobile*. Warrendale, PA: SAE International. 382 p.

Fetkovich, M. J., Fetkovich, E. J., & Fetkovich, M. D. (1996). Useful concepts for decline-curve forecasting, reserve estimation, and analysis. *SPE Reservoir Engineering, 11*(1), 10 p.; Paper presented at the 1994 SPE Annual Technical Conference and Exhibition, New Orleans, LA, September 25–28. https://doi.org/10.2118/28628-PA

General Records of the United States Government: Act of July 2, 1890 (Sherman Anti-Trust Act), Enrolled Acts and Resolutions of Congress, 1789–1992; Record Group 11; U.S. National Archives.

Giddens, P. H. (1938). *The birth of the oil industry*. New York: Macmillan. 216 p.

Ginsberg, J. (2009). *The development of the Pennsylvania oil industry*. Commemorative booklet for ACS National Historic Chemical Landmarks Program, American Chemical Society, Office of Communications, Washington, DC, 4 p.

Glass, J. A., & Kohrman, D. (2005). *The gas boom of East Central Indiana*. Mount Pleasant, SC: Arcadia Publishing. 128 p. (ISBN 0-7385-3963-5).

Gray, R. D. (1994). *Indiana history: A book of readings*. Bloomington, IN: Indiana University Press. 442 p. (ISBN 0-253-32629-X).

Hanson, E. (2000). *The Rockefeller University achievements: A century of science for the benefit of Humankind, 1901–2001*. The Rockefeller University Press. ISBN 9780874700312.

Harper, J. A. (1995). Yo-ho-ho and a bottle of unrefined complex liquid hydrocarbons. *Pennsylvania Geology, 26*(1), 9–12.

Harper, J. A. (1998). Why the drake well? *Pennsylvania Geology, 29*(1), 2–4.

Hildegarde, D. (1959). *The Great Oildorado: The Gaudy and Turbulent years of the first oil rush: Pennsylvania, 1859–1880*. New York: Random House. 277 p.

Hubbert, M. K. (1956). Nuclear energy and the fossil fuels. *API Drilling and Production Practice, 95*, 1–57.

McDonald, G. (2011). Georgius Agricola and the invention of petroleum. *Bibliothèque d'Humanisme et Renaissance, 73*(2), 351–364.

McKithan, C. (1978). *Drake oil well, National Register of historic places inventory – Nomination form 10-300*, U.S. Department of the Interior, National Park Service, 10 p. http://www.dot7.state.pa.us/CRGIS_Attachments/SiteResource/H001206_01H.pdf. Accessed Aug 8, 2019.

Miller, E. C. (1974). *Pennsylvania's oil industry: Pennsylvania History Study 4*. Pennsylvania Historical Association, 69 p.

Poston, S. W., & Poe, B. D., Jr. (2008). *Analysis of production decline curves*. Richardson, TX: Society of Petroleum Engineers. 175 p. (ISBN: 978-1-55563-144-4).

Soeder, D. J. (2012). Chapter 1: Shale gas development in the United States. In H. A. Al-Megren (Ed.), *Advances in natural gas technology*. Rijeka: InTech Open Access. 542 p. (ISBN 978-953-51-0507-7). https://doi.org/10.5772/2324.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

Stevens, P. (2013). History of the international oil industry. In R. Dannreuther & W. Ostrowski (Eds.), *Global resources* (pp. 13–32). London: Palgrave Macmillan.

Tarbell, I. M., & Chalmers, D. M. (1966). *The history of the standard oil company*. Dover Publications, Inc.. 272 p. (ISBN: 978-0-486-13995-1).

The Economist. (2019, Feb 9). Crude Awakening: ExxonMobil and the oil industry are making a bet that could end up wrecking the climate. *The Economist, 430*(9129), 9.

Toyoda, T. (2003). Oil rush: Looking for the land & petroleum. *Osaka Keidai Ronshu, 54*(2), 187–218.

U.S. Court of Appeals for the District of Columbia Circuit. (2001). United States of America, Appellee v. Microsoft Corporation, Appellant, 253 F.3d 34 (D.C. Cir. 2001).

White, J. L. (1968). Columbus Marion "dad" joiner and the East Texas oil boom. *East Texas Historical Journal, 6*(1), 19–32. Article 6.

Williamson, H. F., Daum, A., & Klose, G. C. (1981). *The American petroleum industry: The age of energy, 1899–1959*. Westport, CT: Greenwood Press. 928 p. (earlier edition published by Northwestern University Press).

Yergin, D. (1991). *The prize: The epic quest for oil, money, and power*. New York: Simon & Schuster. 912 p. (ISBN: 0671502484).

Chapter 4
The Energy Crisis and Unconventional Resources

After the Second World War, international exploration efforts found substantial petroleum resources in South America, the Niger Delta, the North Sea, northern Africa, western Australia, and many other places. The biggest oil strikes of all were in the Middle East, starting with the nineteenth century Anglo-Persian Oil Company discoveries in Iran, and culminating in the 1948 discovery of the super-giant (>10 billion barrels) Al-Ghawar oil field in Saudi Arabia. Ghawar is the largest oil field on Earth, having produced some 55 billion barrels of oil by 2005, and is expected to produce at least that much more before depletion (Dunham 2005).

Exploration for oil in the Middle East, North Africa, and elsewhere was initially carried out by the U.S., British and French majors in partnerships with government-owned national oil companies. By the late 1950s, many of the host nations began to realize that the foreign oil companies in these so-called partnerships were raking in a much larger share of the profits than the pittance being paid in royalties to the government. As local populations became more educated in petroleum technology and oilfield engineering operations, many government-run oil companies discovered that they were quite capable of producing petroleum and natural gas on their own without any "help" from the Americans, French or British. Some countries kicked out the foreign oil workers altogether, while others reduced the foreigners to an advisory role, giving the national oil company a majority interest in joint ventures.

This new-found assertiveness caused the major oil companies to largely pull back from upstream production operations in many of these countries. The majors shifted their focus to midstream and downstream roles, collecting crude oil on company-flagged tankers at Middle Eastern and North African ports, shipping it off to their refineries in Texas or elsewhere, and then selling the resulting products through name-brand distribution systems in domestic and international markets. The government-owned oil companies made substantially higher profits from oil production than from royalties, the majors had a steady supply of high-grade crude

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_4

oil for their refineries, and American consumers could purchase gasoline and other petroleum products at bargain prices. It was a win-win process for everyone as long as all the rules were followed.

4.1 The Yom Kippur War and OPEC Embargo

Since the establishment of Israel as a nation in 1947, it has fought a series of wars with its neighbors. Depending on how these are counted, the total varies from eight conflicts listed on the official government website of the Israel Ministry of Foreign Affairs (accessed 8/21/2019; https://mfa.gov.il/MFA/AboutIsrael/History/Pages/Israel-Wars.aspx) to as many as 15 different wars, incursions, uprisings, and police actions considered to be "conflicts" by some historians (Bregman 2016).

Most of these events were over fairly quickly in weeks to months, with the shortest being the Six Day War in 1967. In the autumn of 1973, a war that lasted less than 3 weeks has been variously identified among historians as the Yom Kippur War, the Ramadan War, the 1973 Arab-Israeli War, or the Fourth Arab-Israeli War. Whatever the name, hostilities broke out on the Jewish holy day of Yom Kippur on October 6, 1973 when Egyptian and Syrian armies invaded Israel, followed by armies from Iraq and Jordan. The Israeli Defense Forces (IDF) responded with a counterattack, there was a dust-up lasting for several weeks, and things eventually wound down when a United Nations-brokered ceasefire was put into place on October 25, 1973 (Rabinovich 2004).

Although short, the Yom Kippur War had a number of underlying complications. Tensions between the United States and the Soviet Union were high during this time, and the two Cold War adversaries had made proxies of the participants. The Russians resupplied and armed Egypt, while the Americans supported Israel. As the Israeli counterattack grew in effectiveness, the USSR even threatened direct military intervention, which prompted the U.S. to move into an elevated state of nuclear readiness (Nichols 2014). Nearly everyone in the world was on edge.

America was certainly no innocent bystander or sideline player in the Yom Kippur War. In addition to supplying Israel with military equipment and money, the U.S. also provided the IDF with a substantial amount of actionable intelligence that included U-2 spy plane overflights of Egypt and Syria to observe troop strength and movements. A number of Arab nations felt that supplying crude oil to the United States under these circumstances was clearly aiding an ally of their enemy. Ending oil exports to the U.S. was therefore seen as a strategic requirement mandated by the logic of war.

Things came to a head after U.S. President Richard Nixon requested that Congress provide $2.2 billion in emergency military aid to Israel (Merrill 2007). At a meeting soon afterward of the Organization of Petroleum Exporting Countries (OPEC) in Kuwait on October 20, 1973, Libya introduced a resolution for members of the oil cartel to halt exports to the United States as retribution for aiding Israel. Most of the Arab members of OPEC joined in, and the embargo was also extended to other countries that supported Israel, including the Netherlands, Portugal, and South Africa (Yergin 1991). The OPEC members of the embargo instituted a series of production cuts resulting in shortages that nearly quadrupled the global price of oil from $2.90 a barrel in October 1973 to $11.65 a barrel by January 1974. Disagreements within OPEC about whether or not America had “learned its lesson” resulted in the official lifting of the oil embargo in March 1974, but the higher petroleum prices remained in place for many decades to come (Merrill 2007).

The price increases instituted by OPEC were complicated by the devaluation of the dollar that had occurred in the early 1970s. This was at a time around the end of the Vietnam War when the economy of the United States was experiencing stagnant growth along with monetary inflation. The combination, known as “stagflation” went against most economic theories, because in an economic slowdown with less disposable income the demand for products should have dropped, resulting in steady or falling prices. Instead, prices continued to climb for complicated and poorly-understood reasons, requiring more dollars to purchase the same items, and causing the value of each individual dollar to be less.

Domestic inflation meant that U.S. dollars continuously lost value on global markets. Since the earliest days of petroleum production, the price of oil had been traditionally indexed to the U.S. dollar in cost per barrel, and the falling value of the dollar substantially reduced the amount of revenue that OPEC nations were obtaining from their oil exports. As a result, the OPEC cartel boosted the cost of oil, and began pricing it in grams of gold instead of U.S. dollars (Hammes and Wills 2005).

OPEC had been created in Baghdad, Iraq in September 1960 by five oil-exporting nations: Iran, Iraq, Kuwait, Saudi Arabia, and Venezuela (https://www.opec.org/opec_web/en/; accessed 8/23/2019). Other countries that joined the five founding members include Qatar, Indonesia, Libya, United Arab Emirates, Algeria, Nigeria, Ecuador, Angola, Gabon, Equatorial Guinea, and Congo, although some of these have come and gone. OPEC has been headquartered in Vienna, Austria, since September 1965. Their stated goal is to coordinate petroleum policies among the member nations to secure “fair and stable” prices for petroleum producers. The objective of these policies is to provide an “efficient, economic and regular” supply of petroleum to consuming nations. This eerily echoes the goals promoted by the Standard Oil Trust half a century earlier under John D. Rockefeller.

One of those “consuming nations” was the United States of America. U.S. oil imports had increased significantly since the 1960s, and by 1973 were averaging about 5–6 million barrels per day. However, daily domestic petroleum consumption was about 17 million barrels per day, so imports only made up about 30–35% of the total. In 1973, about half of the imported oil originated in OPEC countries, while the other half came from non-OPEC sources. Thus, even if all OPEC member countries had been willing to go along with a total oil embargo against the U.S. (and not all of them did), it would only have cut supplies by about 15%. The actual reduction in petroleum supplies was closer to 10%, yet this precipitated one of the greatest crises in American history (source: USEIA webpages and data).

4.2 We're Out of Gas

The OPEC oil embargo and resulting "energy crisis" had significant and long-lasting effects on the economy, security, and psychology of the United States (Yergin 1991). Although the embargo only lasted for about 6 months, it is difficult to overstate just how much trauma and concern it caused to the social fabric of the U.S. Indeed, the energy crisis influenced American foreign policy for the next 40 years.

In addition to the price hike, there were severe gasoline shortages and consumer panic. When fuel did become available, lines of vehicles often many blocks long would form at the service stations that had gas (Fig. 4.1). Purchases were typically limited to ten gallons or less per customer to ensure that the fuel was distributed as far as possible and to prevent hoarding. Drivers remained stoic and polite for the most part, but the long and tedious waits in gas lines occasionally sparked displays of anger and loud disputes if someone tried to cut in line out of turn. In the days before the Internet and smart phones, news about gasoline availability at particular service stations was spread by radio announcements and word of mouth. Sometimes people would spot a gasoline tanker truck in transit and follow it to a service station.

Gasoline had been rationed during the Second World War, which few people complained about because of patriotic duty, and a number of localized and brief energy shortages had occurred after the war in places where fuel demand outpaced supply. The OPEC embargo sparked a crisis at a national level unlike any that had

Fig. 4.1 Vehicles lined up waiting for gasoline during the 1973–1974 energy crisis. (Source: D. Falconer, U.S. National Museum of American History; public domain)

been experienced in the past. The oil shortages resulted in the U.S. government considering the possibility of re-introducing gasoline rationing. Small test batches of official gasoline ration coupons were even printed up by the Bureau of Engraving and Printing (better known for paper money) but were never issued. These are now considered rare and prized collector's items. The gasoline shortages experienced during the 1973–1974 energy crisis did result in major changes to U.S. domestic and foreign policy, but none of those changes were what OPEC had intended to achieve with the oil embargo.

Although the oil embargo had been imposed for clearly political reasons, official U.S. government support for Israel never wavered. Instead, American citizens saw the withholding of oil exports as a terrorist act by rogue Middle Eastern countries, and many people felt that the United States was being "held hostage" by foreign oil. The embargo had in fact backfired on OPEC because rather than forcing the U.S. to change Middle Eastern policy, the prevailing view in the United States at the time was that the energy crisis was a technology issue that could be solved with more technology. America was still on a high tech high from the recent success of the Apollo moon missions, and a common saying was "If we can land a man on the moon, we ought to be able to figure out how to fuel our cars." Some of this sentiment is still with us today.

One reason the oil embargo had such a significant impact on the lives of everyday Americans was due to the demographic changes that had occurred after the Second World War. In the latter half of the twentieth century, many people in the U.S. moved out of the inner cities and into post-war suburban housing. A large group of customers for the "American dream" of single-family home ownership were WWII military veterans who had postponed plans to get married and start families until after the war. This pent-up demand was being met with new housing stock that had been hastily constructed in previously rural areas adjacent to city limits and featured relatively inexpensive, cookie-cutter designs. Many veterans were able to purchase new houses under the Veterans Administration (VA) home mortgage loan program authorized in 1944 as part of the GI Bill (and still active to this day). The VA loans greatly expanded home ownership in the U.S. (https://www.va.gov/about_va/vahistory.asp accessed 9/10/19).

Beyond the availability of new housing stock, reasons for the migration from cities to the suburbs were multiple and complex. One was the so-called "white flight" from the northern cities to the suburbs. Large numbers of African-Americans had arrived in these cities during the 1940s to take wartime manufacturing jobs, and stayed on. Many of these people had earned enough money from factory work to become first-time homeowners, and demand soared. In order to provide a supply of housing stock, some real estate agents practiced "blockbusting," which is now illegal. Unscrupulous agents would play to the racist fears of many urban whites, urging them to sell out and move to the suburbs or risk declines in property values once "the blacks" moved in, along with an increase in crime. Sometimes every home in an entire city block would go up for sale at the same time, hence the name. The real estate agents themselves weren't necessarily racist. They received their commissions no matter who bought the house.

At the same time, southern and western cities were experiencing population and economic expansions because the widespread, post-war use of air conditioning had made living in the south much more bearable. Most of the southern expansion was targeted onto low-cost farm land in formerly rural areas adjacent to towns, creating rings of suburban sprawl around such cities as Atlanta, Dallas, and Houston. Another factor was the fear of atomic weapons during the early days of the Cold War, when many people felt that the suburbs would be less of a target than the central parts of cities in the event of a nuclear exchange.

In any case, the suburbs had been built for the automobile without the transportation infrastructure that existed in the inner cities. City transport options like buses, streetcars, and electric rail lines were simply not available in the suburbs, and even pedestrian sidewalks and bicycle paths were often hard to find. The only major post-war transportation infrastructure project built on a national level in the U.S. was the Eisenhower Interstate Highway System, and the new freeways quickly became the preferred travel route from anywhere to anywhere.

Thus, the automobile became the primary means of transportation in America. By the end of the 1960s, the United States had become almost totally dependent on gasoline-fueled vehicles for travel to work, shopping, church, school, and almost everywhere else. Institutions like drive-in movies, drive-up bank tellers, and drive-in restaurants were established in response to the ascendancy of the motor car, and became common sights on the suburban landscape. Families often owned multiple vehicles, especially if they had driving-age children. Prior to World War Two, owning more than one automobile per family was practically unheard of, except for the very wealthy.

The proliferation of cars in the suburbs soon led to their increased use within the cities themselves. Many older American cities, especially those in the east had street layouts designed in horse and buggy days. For example, less than 5 minutes of driving around in downtown Boston should be enough to convince anyone that the city is not designed for automobiles. Newer, western cities like Los Angeles were constructed with automobiles in mind, resulting in truly mind-boggling urban sprawl and making Los Angeles the largest city in the United States in terms of land area. The movement of vehicles into and out of cities as people drove to and from work resulted in yet another post-war invention: the rush hour traffic jam.

The energy crisis left people stranded in the suburbs with an empty gas tank in a useless car and no other transportation options. Because of the spread-out nature of the suburbs, walking was impractical for most tasks. Suburbanites felt helpless. When gasoline did become available, drivers discovered that the cost had doubled, and then quadrupled as the OPEC-controlled market ratcheted up the price of crude oil (Merrill 2007). Some people may chuckle today at the thought of gasoline prices rising from 40 cents a gallon in the fall of 1973 to $1.60 a gallon by the spring of 1974, but for a modern-day perspective, multiply the cost of your next fill-up by four. Imagine $25 worth of gasoline costing $100. This is the level of financial pain inflicted on the American consumer by the OPEC embargo and gasoline price hikes.

It wasn't just gasoline. Heating oil, jet fuel and diesel fuel also experienced similar shortages and price increases, impacting homeowners with oil heat and straining the finances of the airline and trucking industries. Electrical power plants using fuel oil to generate electricity saw costs go through the roof. Many of these were hastily converted over to natural gas or coal, leading to shortages of those commodities and causing additional price hikes.

The inter-dependence of energy resources in the United States and the seemingly never-ending shortages and supply uncertainties on every kind of energy at almost every level is why the OPEC embargo was not just about oil, but actually resulted in a full-blown “energy crisis.” This trauma has caused repercussions in American politics and policies ever since. Even though domestic energy supplies in the United States are now adequate and stable, and have been for a decade, fears about the use of oil as a weapon, the desire to protect foreign oil fields and tanker transport routes, and the prospect of crippling energy shortages are still interwoven throughout the American psyche and continue to influence government policy. The U.S. Congress acted in 1975 to ban oil exports from the United States to retain as much domestic oil within the country as possible. This ban remained in effect for 40 years until it was lifted in 2015.

A second, smaller oil shortage occurred in 1979, when Iranian petroleum production was disrupted for several months by the shutdowns and disarray associated with the Islamic revolution. The 1979 crisis was less severe in the United States than the OPEC embargo because only a relatively small amount of U.S. oil imports came from Iran, and Saudi Arabia and other exporting nations were able to quickly make up the shortages.

The 1970s were a watershed decade for energy in America. The nation began the decade blissfully unaware of any potential problems in the energy supply chain. It entered the 1980s wondering if the transportation of the future might be steam-powered buses fueled by wood. The modern controversy over fracking and the use of fossil fuels cannot be understood without understanding the energy shortages of the 1970s. The development of shale gas and tight oil were a direct response to the OPEC oil embargo and the resulting critical shortage of domestic energy caused by America’s dependence on imports. The fact that this effort took 30 years to bear fruit is beside the point. The complex inter-relationships between oil, money, power, and politics that resulted in the 1970s energy crisis were explored in a book by Daniel Yergin (1991). It is recommended for further reading.

4.3 The Unconventional Solution

After the OPEC embargo officially ended in March of 1974, the U.S. government responded with a number of actions that were designed to reduce American dependence on oil imports. The three factors that affect energy: technology, economics, and policy made some solutions more feasible than others (Soeder and Borglum 2019). Because of the panic at the time, the government tried nearly everything, including a few things that might have been better left untested. Success was eventually achieved with some of the new technologies, including the practical development of shale gas and tight oil that completely changed the energy economy in the world 30 years later.

On August 4, 1977, the U.S. Department of Energy (DOE) was created as a cabinet-level entity of the U.S. government under President Jimmy Carter. James R. Schlesinger was named the first Secretary of Energy. Along with inherited duties like running the national labs and maintaining the nation's nuclear weapons stockpile, a primary mission of the new DOE was to find technological solutions to energy supply and use, and prevent the U.S. from falling into another energy crisis.

Astute readers may note that it took more than three years after the end of the OPEC oil embargo to create DOE. This is not unusual for any kind of major government restructuring effort, especially one that involves the creation of a new, cabinet-level agency. In the case of DOE, there were a number of pre-existing government bureaus and agencies with mission statements that fit under the DOE umbrella. Working out turf issues and budgets among these various entities, many of whom had champions in Congress, was a major political challenge. Eventually, through compromise and some old-fashioned horse trading, Congress was able to roll up a slew of smaller agencies into the new Energy Department.

The U.S. Department of Energy took a two-pronged approach toward avoiding another energy crisis: (1) improve energy efficiency so we consume less and (2) increase the domestic energy supply so we have more. The first goal resulted in things like the development of low-wattage LED lighting, improvements in home insulation, more fuel-efficient vehicles, and Energy Star ratings on appliances to encourage greater energy efficiency.

To achieve the second goal, the agency set out to identify and investigate almost every new potential source of domestic energy under the sun, including the sun itself. Over the past 40 years, DOE has funded research and engineering projects on solar photovoltaic, solar thermal, onshore and offshore wind, high and moderate temperature geothermal, fuels from biomass, ocean energy such as waves and tides, oil shales, tar sands, new nuclear technologies, energy conversion technologies such as coal gasification, coal-to-liquids, and gas-to-liquids, as well as developing new sources of natural gas. The overall goal of DOE was to produce as much new, additional domestic energy as possible to offset oil imports. This so-called "all-of-the-above" energy strategy has been a U.S. government policy since the end of the energy crisis. Reducing dependence on a single resource like oil helps to spread out the risk of potential future supply disruptions.

A major objective of the DOE energy supply research was to develop new sources of liquid fuels that could directly replace gasoline in motor vehicles and thus reduce the need for imported oil. This became a chemical engineering project, as researchers sought new ways to turn coal or natural gas into liquids. The primary focus was coal, both because of its abundance in the United States, and the fact that a chemical process already existed for turning it into liquid fuels.

During the latter stages of World War II, the German military was beset by fuel shortages. This was due in part to a strategic bombing campaign by the Allies that targeted oil refineries, transport trains, and fuel depots to deny petroleum supplies to the German *Wehrmacht* and aviation fuel to the *Luftwaffe* (Caldwell and Muller

2007). The Nazis also lost access to oilfields in the Caucasus and the strategic oilfields at Ploesti, Romania as the armies of the Soviet Union drove them westward. Heavy German tanks like the Panzer II and the Tiger guzzled fuel, and keeping them supplied was challenging even under good conditions. In some skirmishes late in the war, such as the Battle of the Bulge, many German armored vehicles simply ran out of fuel and ended up stranded on the battlefield.

In desperation, the Germans set up synthetic fuel or “synfuel” plants to make liquid fuels from coal, which was abundant in Germany and Poland. The synthesis process had been invented in the 1920s by two German chemists: Franz Fischer and Hans Tropsch. The “Fischer-Tropsch” (FT) catalytic chemical process works by first creating synthesis gas from coal (the carbon monoxide and hydrogen gas mixture described earlier in the manufacture of “town gas”). Transition metal catalysts such as iron, cobalt, or nickel are used to convert this syngas into paraffin and olefin wax composed of long-chain hydrocarbons. The wax is then cracked into shorter chain hydrocarbons to produce the desired liquid fuels (source DOE websites).

This so-called coal-to-liquids (CTL) process is complicated and expensive. During the war, of course, the Nazis cared little about the cost, but American consumers were not willing to pay a higher price for synfuels just to be free of OPEC oil. DOE pushed hard to improve the economics by funding a variety of synfuel pilot projects in the 1980s aimed at making the process more streamlined and efficient, and bringing the cost of the resulting products more in line with traditional fuels refined from petroleum and natural gas. Although many of these concepts worked physically, all were abject economic failures. No matter how efficient the synfuels manufacturing processes became, none were ever able to produce liquid fuels that were cost-competitive with petroleum. Many of these old CTL pilot projects remain visible across the American landscape today (Fig. 4.2).

Natural gas was viewed by DOE as an under-utilized fuel that could displace heating oil and fuel oil, effectively freeing-up liquid hydrocarbon resources to provide more diesel fuel and gasoline for vehicles. Research on new sources of natural gas supply focused initially on developing the technology to efficiently recover gas from coal seams, tight sands, gas dissolved in deep brines under high pressures (known as geopressured aquifers), and gas in organic-rich, black shales (Schrider and Wise 1980). Natural gas resources added later on included methane hydrates, secondary recovery of gas trapped in watered-out conventional reservoirs, and abiogenic gas, a controversial hypothesis that claims primordial methane from the formation of the solar system still exists deep within the Earth.

Oil and gas resources fall into two broad categories: conventional and unconventional. As explained back in Chap. 1, the types of source rock that create oil and gas tend to be fine-grained and very low in permeability. Conventional O&G resources require five things: (1) an organic-rich source rock, (2) sufficient thermal maturity to generate petroleum and natural gas, (3) a suitably porous and permeable reservoir rock, (4) a trap and seal on the reservoir rock, and (5) a migration pathway from source to reservoir (Selley 2014). The challenges inherent in having all of these occur in the right order and with the correct timing makes the discovery of huge

Fig. 4.2 Abandoned, 1980s era coal-to-liquids (CTL) pilot plant south of Rapid City, SD. (Photographed in 2019 by Dan Soeder)

conventional oil resources like Al-Ghawar or the East Texas oilfields all the more amazing.

Unconventional O&G resources, on the other hand, are produced directly from the source rock itself, or sometimes from an adjacent rock unit. These are called "continuous resources" by the USGS (Charpentier and Cook 2011) because they do not require reservoir rocks, traps and seals, or migration pathways. The geological definition for an unconventional resource is that the hydrocarbons are produced out of the rock where they formed. However, because these rocks are usually fine-grained and impermeable, petroleum engineering techniques of reservoir stimulation are required to improve production, often involving hydraulic fracturing. Thus the engineering definition for an unconventional resource is that some form of stimulation must be applied to achieve economic production.

Unconventional hydrocarbon resources include light tight oil (LTO) in shales, limestones, and other low-permeability rocks, tight gas sands, shale gas, natural gas liquids (NGL) also known as "condensate", heavy oil sands or "tar" sands, coalbed methane, methane hydrates, and oil shale (Nash 2018). Oil shale is different from shale oil or LTO resources; instead of liquid hydrocarbons, it contains solid kerogen that must be heated to a higher level of thermal maturity to create petroleum. Oil shale is either mined and processed off-site, or retorted in place. Despite decades of efforts, it has never been cost-competitive with conventional oil.

There was no doubt that the development of unconventional resources would be a technical challenge, and the DOE approach was very technological and engineering-oriented. Unfortunately, little consideration was given to the economics, which turned out to be important for any of these resources to be produced in the real world.

The Eastern Gas Shales Project (EGSP) was started in 1975 by the Energy Research and Development Administration, a predecessor agency to DOE. The objective was to assess the natural gas resource potential of organic-rich, black shales in eastern U.S. sedimentary basins because of their proximity to significant natural gas usage areas in the Great Lakes region and large cities in the Northeast. The project contained three major components: resource characterization, development of production technology, and the transfer of that technology to industry (Soeder 2017).

Multiple shale drill cores were collected under the EGSP from the Appalachian basin, Michigan basin, and the Illinois basin between 1976 and 1982 for a project total of 44 (Bolyard 1981). DOE used a series of cooperative agreements set up with established drilling companies to obtain the core material. The shale formations of interest ranged from the Upper Devonian Cleveland Member of the Ohio Shale to the Middle Devonian Marcellus Shale in the Appalachian basin, along with the Upper Devonian Antrim Shale in Michigan, and the similar-age New Albany Shale in the Illinois basin (Fig. 4.3).

Drill cores were 3.5 inches (8.9 cm) in diameter, and all were directionally oriented (Cliffs Minerals, Inc. 1982). The cores were characterized for lithology, color, and orientation of natural fractures. They were also photographed and gamma radiation readings were obtained at one-foot (30 cm) intervals for comparison with wireline gamma well logs. Rock samples were collected from the cores for the various labs, government agencies and universities that had requested them. The cores were eventually transferred to the state geological survey in the state where each had been cut. The EGSP was managed by the DOE Morgantown Energy Technology Center (METC) in West Virginia, which is now a campus of the DOE National Energy Technology Laboratory (NETL).

One of the participants engaged in the EGSP coring was Mitchell Energy, a mid-size production company run by George P. Mitchell. Back in the 1950s, Mitchell was working as a consulting geologist on some oil and natural gas prospects. The small drilling company he had started with his brother Johnny and a few other partners acquired a supposedly worthless lease in north Texas that turned out to have gas and oil production from more than 30 separate fields. By the mid-1960s, Mitchell Energy had become the nation's top independent gas producer.

Mitchell Energy drilled and cored a number of shale wells in Ohio under the Eastern Gas Shales Project in 1978 and 1979. The wells proved to be non-productive, but George Mitchell remained intrigued by the gas potential of black shale, and in 1981 he began focusing on the Barnett Shale in the Fort Worth Basin of Texas near Mitchell Energy's home office in Dallas.

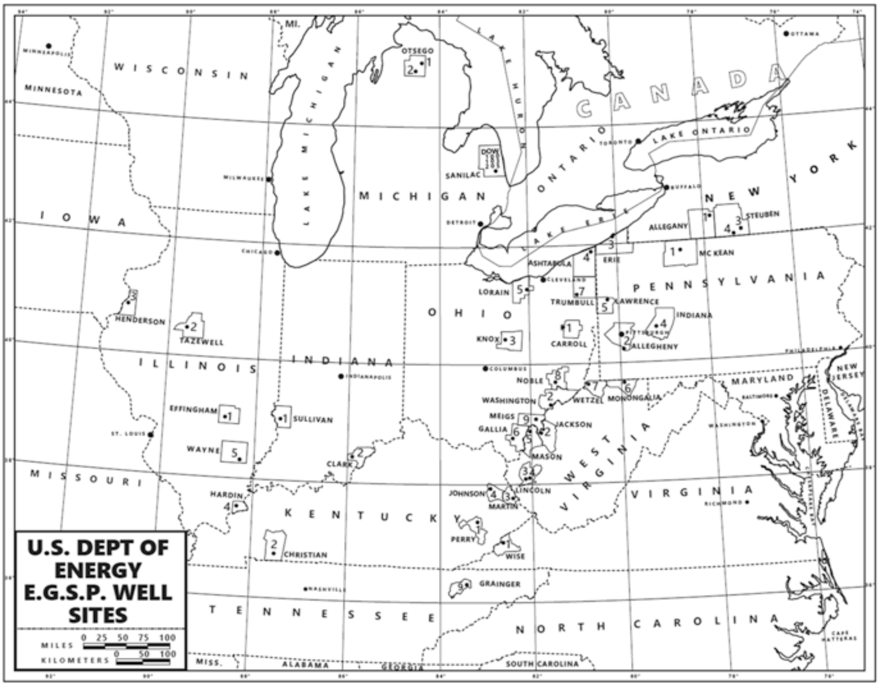


Fig. 4.3 Map of EGSP well locations designated by DOE number and shown within counties in the central and eastern United States. (Source: Cliffs Minerals, Inc., 1982 (public domain)

The EGSP had run a series of field-based engineering experiments that attempted to use hydraulic fracturing to link up existing natural fracture networks in the shale and create high-permeability flowpaths into large volumes of rock. Many different reservoir stimulation technologies were tried, ranging from standard water-based fracks to more exotic tests with cryogenic liquids or kerosene. The different treatments worked in some wells but not in others, and nobody had a good understanding of why the results were so hit-or-miss. DOE was left to conclude that reservoir stimulation alone was not the key to success with shale, but additional, unknown factors were involved (Horton 1981). In hindsight, the main problem turned out to be that almost no one was thinking big enough.

By the time the EGSP formally ended in 1992, a number of cutting edge experiments had been done on shale. Innovative well logging techniques, reservoir anisotropy assessments, liquid CO_2 fracturing, and a number of other new technologies came out of the EGSP. In December 1986, DOE drilled an experimental horizontal test well 2000 feet (610 m) into the Huron Shale in West Virginia to intercept the primary vertical natural fracture system for improved gas recovery efficiency (Duda et al. 1991). This was the first known horizontal well drilled into a black shale, and it produced moderate amounts of gas. George Mitchell took note of it.

The Late Mississippian Barnett Shale in the Fort Worth basin is named for a "typical exposure" of the unit at Barnett Springs, about 6.5 km (4 miles) east of the town of San Saba, Texas (Bruner and Smosna 2011). Like other black shales, obtaining economical amounts of gas from vertical wells in the Barnett was challenging. Over a period of about 18 years, Mitchell Energy tried several different drilling techniques and reservoir stimulation methods on the Barnett including massive hydraulic fracture stimulations. These produced significant flows of gas but at a very high cost. George Mitchell looked into other types of innovative technology to produce the gas, and stubbornly refused to quit. Nearly everyone suggested that he do so. His brother and partners pleaded with him to walk away from the Barnett. Others in the oil and gas business thought Mitchell's obsession with shale was an old man's eccentricity. Even his own employees considered the Barnett Shale to be a waste of time and money (Kinley et al. 2008).

By 1997, George Mitchell had found two technologies that appeared to work in shale. The first was horizontal, or more correctly, "directional" drilling developed for deepwater offshore platforms. The second was a more cost-effective hydraulic fracturing technique known as a "light sand" frack and the use of a downhole friction reducer called "slickwater."

The high cost of moving semi-submersible, tension leg platforms anchored in kilometers-deep water far offshore led the major oil companies to invest a substantial amount of money into improving directional drilling technology in the late 1980s. Directional drilling had been around since the 1930s, but it was difficult to turn a borehole too sharply without breaking the drill pipe, and it was also challenging to know the location of the hole deep underground. Being able to drill directional boreholes from an offshore platform meant that multiple wells could tap into different reservoirs from a single location.

Two innovations greatly improved the technology of directional drilling. The first was the "bottomhole assembly" that used a downhole motor to turn the drill bit without having to rotate the entire drill string from the surface. The hydraulic pressure of drilling mud pumped down through the drill pipe from the surface ran the motor. Stationary drill pipe can make tight turns much more readily than drill pipe that has to rotate. The second innovation was improved borehole directional location, downhole navigation, and telemetry of data back up to the surface known as "measurement while drilling" (MWD) and "logging while drilling" (LWD). A whole new geologic profession called "geosteering" has sprung up to interpret the downhole data and provide guidance for directional boreholes.

Mitchell realized that with the horizontal boreholes or laterals, he could make much greater contact with the shale, staying within the formation for kilometers instead of a few dozen meters at most if he penetrated it vertically. The horizontal well would also allow him to frack in multiple stages at different locations along the length of the lateral, instead of the single stage fracks that were typical of vertical wells.

Because the runs of production tubing in horizontal wells were significantly longer than in vertical wells, a friction-reducing additive called polyacrylamide was introduced to the frack fluid as a lubricant, creating an extremely slippery liquid known as "slickwater." Mitchell developed hydraulic fracturing techniques that introduced a small amount of shear into the shale, causing rough spots or "asperities" on the fracture walls to be offset slightly from one another to help prop the fracture open. This allowed him to use less sand for proppant, saving money and creating the "light sand frack" (Montgomery and Smith 2010).

Horizontal drilling and the staged, light sand slickwater frack began achieving success in the Barnett Shale in the late 1990s (Montgomery et al. 2005). A Barnett Shale gas drilling boom began in the Dallas-Fort Worth area, including quite a few wells within the city limits of Fort Worth itself (Martineau 2007). A substantial amount of drilling was done near the DFW airport, and many of these production wells are visible from an aircraft window upon approach (Soeder and Borglum 2019).

Mitchell Energy was acquired by Devon Corporation in January 2002 for a cool $3.1 billion dollars, and at the age of 84 George P. Mitchell finally walked away from the Barnett Shale. He received a Lifetime Achievement Award from the Gas Technology Institute on June 16, 2010 for his role in pioneering shale gas into an economic resource, and for essentially creating the shale gas revolution. He died on July 26, 2013.

The O&G industry does not keep secrets well, and word soon got out about Mitchell's success in the Barnett Shale. Southwestern Energy quietly acquired substantial acreage in northern Arkansas, and by 2004 gas production from the Fayetteville Shale using Mitchell's methods was booming. This was followed soon afterward by development of the Haynesville, Bakken, Marcellus, Woodford, Niobrara, Eagle Ford, Utica, and the stacked play in the Permian Basin. These ten production plays of shale gas and tight oil represent the core of the fossil fuel revolution (Fig. 4.4). By 2013 the United States had become the largest hydrocarbon producer in the world, finally putting an end to the energy crisis (Soeder and Borglum 2019).

The economics of shale gas and tight oil depend on high commodity prices. The cost of horizontal drilling and especially the staged, high-volume hydraulic fracturing (HVHF) operations required to produce hydrocarbons from these tight formations make the "break-even" price of oil and gas significantly higher than from conventional well completions. Shortages of natural gas and petroleum drive prices upward, creating favorable economics for HVHF treatments to produce hydrocarbons. Companies then rush in to take advantage of the boom, and the resulting glut in production greatly increases the supply, causing prices to fall.

For reasons unknown, the energy industry always seems to be surprised and unprepared when the bubble bursts, even though it is as predictable as a summer thunderstorm. Many shale production companies have been left drowning in debt from the collapse of prices brought on by their own over-production. This could be understood if it was a one-time occurrence, but it seems to happen over and over again on a regular basis.

The Ten Major U.S. Shale Plays

Formation	Age	Basins & Location	Initial Developer	Year	Production Depths	Production	Core Areas
Barnett Shale	Mid to Late Miss	Fort Worth, TX	Mitchell (Devon) Energy	1997	3 - 8k ft	gas, NGL	Newark East Field; NW of Ft. Worth
Fayetteville Shale	Late Miss	Arkoma, AR	Southwest Energy	2004	3 - 6k ft	dry gas	North-central Arkansas
Haynesville Bossier	Late Jurassic	Arkla, TX-LA	Chesapeake Energy	2005	10k - 13k ft	dry gas	Lufkin, TX to Shreveport, LA
Marcellus Shale	Mid Devonian	Appalachian, WV, PA	Range Resources	2007	3 - 9k ft	gas, NGL	SW PA & NW WV; NE PA
Bakken Formation	Late Devonian to Early Miss	Williston, ND, MT, SK	EOG & Continental Resources	2006 - 2009	4k - 11k ft	oil, gas	NW North Dakota, E. Montana, Canada.
Woodford Shale	Late Devonian	Anadarko, Ardmore, OK	Newfield Exploration	2005	4k - 25k ft	bio, oil, NGL, dry gas	central & southern Oklahoma
Niobrara Formation	Late Cretaceous	Denver; Powder River, CO, WY	Whiting Petroleum	2008	3 - 11k ft	bio, NGL, dry gas	E. Colorado, E. Wyoming
Eagle Ford Shale	Late Cretaceous	Brazos, Maverick, TX	Petrohawk Energy	2008	3 - 20k ft	oil, NGL, gas	southern Texas
Spraberry, Wolfcamp, Bone Spring, Glorieta, Yeso, and Delaware formations.	Mid to Late Permian	Permian, TX	Multiple	2009	~2k - 25k ft	oil, NGL, gas	western Texas; southeast New Mexico
Utica/Point Pleasant	Mid Ordovician	Appalachian, OH	Multiple	2011	3 - 15k ft	gas, NGL	southeast Ohio

Fig. 4.4 The ten major shale gas and tight oil plays in the United States (Source: Summarized from Soeder and Borglum 2019 (NGL = natural gas liquids; bio = biogenic gas). Many of these formations outcrop at the surface, but a minimum production depth of 2500–3000 feet is required for fracking)

References

Bolyard, T. H., (1981). *A summary and evaluation of the eastern gas shales program cored wells in the Appalachian Basin*. Science Applications, Inc., prepared for U.S. Department of Energy under contract DE-AM21-78MC08216, September, 32 p.

Bregman, A. (2016). *Israel's Wars: A History since 1947* (4th ed.). New York: Routledge Publishing. 360 p. (ISBN:978-1138905368).

Bruner, K. R., & Smosna, R. (2011). *A comparative study of the Mississippian Barnett shale, Fort Worth Basin, and Devonian Marcellus shale, Appalachian Basin, report DOE/NETL-2011/1478*. URS, Inc., prepared for U.S. Department of Energy, 106 p.

Caldwell, D., & Muller, R. (2007). *The Luftwaffe over Germany: Defense of the Reich*. Great Britain: Greenhill Books. ISBN 978-1-85367-712-0.

Charpentier, R. R., & Cook, T. A. (2011). *USGS methodology for assessing continuous petroleum resources*. U.S. Geological Survey Open File Report 2011–1167, 75 p.

Cliffs Minerals, Inc. (1982, February). *Geologic analysis of Devonian shale cores: Final report*. Prepared for U.S. Department of Energy under contract DE-AC21-78MC08199, 86 p. plus appendix.

Duda, J. R., Salamy, S. P., Aminian, K., & Ameri, S. (1991, August). Pressure analysis of an unstimulated horizontal well with type curves. *Journal of Petroleum Technology*, 988.

Dunham, L. (2005). Saudi Arabia's Ghawar field: The elephant of all elephants. *AAPG Explorer*, January 2005.

Hammes, D., & Wills, D. T. (2005). Black gold: The end of Bretton woods and the oil price shocks of the 1970. *Independent Review, 9*(4), 501–511.

Horton, A. I. (1981). *A comparative analysis of stimulations in the eastern gas shales*: U.S. Department of Energy report DOE/METC 145, 120 p.

Kinley, T. J., Cook, L. W., Breyer, J. A., Jarvie, D. M., & Busbey, A. B. (2008). Hydrocarbon potential of the Barnett shale (Mississippian), Delaware Basin, west Texas and southeastern New Mexico. *American Association of Petroleum Geologists Bulletin, 92*, 967–991.

Martineau, D. F. (2007). History of the Newark east field and the Barnett shale as a gas reservoir. *American Association of Petroleum Geologists Bulletin, 91*, 399–403.

Merrill, K. (2007). *The oil crisis of 1973–1974: A brief history with documents*. Boston: Bedford/St. Martin's. 192 p. (ISBN 9780312409227).

Montgomery, C. T., & Smith, M. B. (2010). Hydraulic fracturing: History of an enduring technology. *Journal of Petroleum Technology, 62*(12), 26–32.

Montgomery, S. L., Jarvie, D. M., Bowker, K. A., & Pollastro, R. M. (2005). Mississippian Barnett Shale, Fort Worth Basin, North-Central Texas: Gas-shale play with multi-trillion cubic foot potential. *American Association of Petroleum Geologists Bulletin, 89*(2), 155–175.

Nash, S.N. (2018). *New technologies in the development of unconventional resources in the US.* American Association of Petroleum Geologists Search and Discovery Article #70331, Posted April 30, 2018, Evening Technical Presentation: Universidad Nacional de San Marcos and the Universidad Nacional de Ingenieria, Lima Geological Society, Lima, Peru, March 16, 2018, 33 p.

Nichols, T. (2014). *No use: Nuclear weapons and U.S. National security*. Philadelphia: University of Pennsylvania Press. 213 p.

Rabinovich, A. (2004). *The Yom Kippur War: The epic encounter that transformed the middle east*. New York: Schocken Books. 543 p. (ISBN:0805241760).

Schrider, L. A., & Wise, R. L. (1980, April). Potential new sources of natural gas. *Journal of Petroleum Technology*, 703–716.

Selley, R. (2014). *Elements of petroleum geology* (3rd ed.). Cambridge, MA: Academic. 526 p. (ISBN 9780123860316).

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

Yergin, D. (1991). *The prize: The epic quest for oil, money, and power*. New York: Simon & Schuster. 912 p. (ISBN: 0671502484).

Chapter 5
Fracking and Air Quality

The environmental impacts of fracking on the atmosphere are complex, and in the minds of many people, the concerns associated with the fracking process are part of the broader concern about climate change and the use of fossil fuels. These are really two separate issues, especially when related to air quality. The first issue is the air pollution caused by the hydraulic fracturing process itself, when pump trucks are releasing diesel smoke, heavy equipment is raising clouds of dust, and chemicals and returned fluids may be off-gassing significant quantities of volatile organic compounds into the air.

The second issue has to do with the greenhouse gas (GHG) released as a combustion product of fossil fuels, primarily carbon dioxide (CO_2) that results in global warming and climate change. This has something, but not everything to do with fracking. Certainly natural gas and petroleum recovered by fracking do contribute to global GHG concentrations when produced and burned. But a far larger contributor is the combustion of coal, and the production of coal has nothing whatsoever to do with fracking. This chapter focuses on the direct impacts of the fracking process on air quality. The larger issues of greenhouse gas emissions and climate change from the use of fossil fuels are presented and discussed in later chapters.

Potential air quality impacts from fracking and other phases of unconventional oil and gas development have been investigated in a number of oil and natural gas production areas in the United States, mainly in northeastern Pennsylvania, eastern Colorado and the Denver region, and the Dallas-Fort Worth area in Texas (HEI 2019). Both direct measurements and modeling approaches were used, including personal sampling, mobile and stationary sampling at the ground surface, and measurements collected from aircraft and satellites. Most of the studies were focused on air quality near oil and gas operations (e.g. Eisele et al. 2016; Banan and Gernand 2018), although several investigators have also looked at the degradation of air quality from fracking activities within a larger regional context of urban air pollution (e.g. Bari and Kindzierski 2018; Garcia-Gonzales et al. 2019).

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_5

Measurement of air emissions from oil and gas production operations and other processes have been made using a variety of methods, including direct measurements of specific chemicals, and downwind measurements using chemical tracers to identify sources (e.g., Nathan et al. 2015; Allen 2016; Pekney et al. 2018). A focus area on natural gas operations in particular has been the characterization of methane emissions, since methane is the main component of natural gas (e.g., Omara et al. 2018; Johnson et al. 2019; Ren et al. 2019). Methane leakage from wellbores and surface equipment like pipelines and compressors is a concern due to its flammability in air, and also because methane is a more powerful GHG than CO_2, although it is less persistent in the atmosphere. Other emission measurements have included volatile organic compounds (VOCs) (Pétron et al. 2014), nitrogen oxides (NOx) (Goetz et al. 2015), black carbon soot (Schwarz et al. 2015) and dust (Litovitz et al. 2013).

The air pollution associated with fracking and other O&G operations falls into three main categories: (1) particulate matter, (2) organic gases, and (3) nitrogen oxides. Particulate matter or PM consists of dust and smoke from activities like site preparation and drilling activities, material transport on and off the pad, and proppant handling and use. Sources of PM include diesel and other engine exhaust, tire, brake and road dust, and silica dust from proppant sand (Moore et al. 2014). Organic gases include VOCs like benzene, toluene, ethylbenzene and xylenes (known collectively as BTEX) from engine exhaust, well completions, vented tanks, fluid transfer operations, flaring, equipment leaks, pneumatic controllers and valves (Luck et al. 2019), and storage and transport of drilling waste (Allen 2016). Organic gases may also consist of light hydrocarbons such as methane, ethane, propane, and butane that volatize into the air when formation water is brought to the surface and stored in open pits or vented tanks (Pekney et al. 2014). Nitrogen oxides or NOx are a byproduct of high-temperature combustion and can be found in engine exhaust during site preparation, material transport, drilling and fracking, and gas compressors (Zielinska et al. 2014).

5.1 Particulate Matter

Diesel and gasoline-powered construction equipment used for site preparation, drilling, and hydraulic fracturing emit nitrogen oxides (NOx), particulate matter (PM), volatile organic compounds (VOCs), polyaromatic hydrocarbons (PAHs), methane (CH4), and other compounds into the air (Moore et al. 2014). A significant air quality concern with the oil and gas production process in general, and fracking in particular, is the amount of PM emitted by these operations.

Referring back to the hydraulic fracturing operation pictured in Fig. 2.1, a puff of diesel smoke is visible above the pump trucks, and a haze of dust is present over the sand tank at the left rear of the photo. Both of the clouds in this photo are composed of particulate matter, defined by the EPA as a mixture of solid particles and liquid droplets found in the air (https://www.epa.gov/pm-pollution/

particulate-matter-pm-basics; accessed 10/2/2019). There are respiratory concerns with these materials.

Substances that are small enough to be inhaled by the human respiratory system make up the PM that people worry about. These are generally divided into two size classes: PM_{10} consists of particulates with diameters of 10 micrometers or less, and $PM_{2.5}$ consists of even smaller particles with diameters equal to or less than 2 ½ micrometers. Broadly speaking, PM_{10} is dust, and $PM_{2.5}$ is smoke. The smaller the particle, the deeper it can travel into the lungs.

Much of this material is fairly benign – after all, people breathe in household dust all the time with no ill effects other than a sneeze, and wood smoke from a campfire causes watery eyes and barbecue-scented clothes but creates little permanent damage. However, some of the dust and smoke on industrial sites like a well pad can pose significant risks to human health. Frack sand, for example, typically consists of crystalline silica (SiO_2) in the form of quartz. Inhaling quantities of PM_{10} quartz dust can lead to silicosis, an emphysema-like illness resulting from the scarring of lung tissue by the sharp particles. A more intense form of the disease from acute dust exposure can even cause the alveoli of the lungs to be filled with dust particles and permanently blocked (source: U.S. Centers for Disease Control [CDC] websites).

In addition to quartz, silica can occur in four other different crystal structures known as polymorphs: coesite and stishovite, which are fairly rare, and tridymite and cristobalite, which are more common. Tridymite and cristobalite are high-temperature, low-pressure polymorphs of silica that typically occur in volcanic rocks, but they can also form in lower temperature environments through processes like the devitrification of silica-rich glass (Jones and Segnit 1972). Cristobalite is particularly dangerous to inhale – it forms needle-like crystals similar to asbestos that can penetrate and damage lung tissue. There is also evidence that cristobalite is a potent carcinogen, and some studies indicate that other minerals fused to the edge of cristobalite crystals can make the material even more toxic (Horwell et al. 2012).

The most common finer particulate matter ($PM_{2.5}$) encountered during drilling and fracking is black smoke from diesel exhaust. Diesel emissions consist of vapor-phase exhaust gases and diesel particulate matter or DPM. DPM is made up of $PM_{2.5}$ soot particles with a solid core of elemental carbon, surrounded by other chemical substances attached to the carbon surface, including metals, sulfates, silicates and aromatic hydrocarbons. Short term exposure to high concentrations of exhaust or DPM can result in headaches, dizziness, and irritation of the eye, nose and throat. In June 2012 the International Agency for Cancer Research (IARC) classified diesel exhaust and DPM as known human carcinogens. Prolonged exposure can increase the risk of cardiovascular, cardiopulmonary and respiratory disease, and lung cancer (https://www.osha.gov/dts/hazardalerts/diesel_exhaust_hazard_alert.html; accessed 10/3/2019).

The hazards posed by particulate matter emitted during drilling and fracking operations on shale gas or tight oil well sites are similar in nature and intensity compared to those from other construction sites. Oil and gas wells are basically short-term construction projects and while they do emit dust and smoke during their active phases, it is important to note that these occur within a limited time frame that is considerably shorter than the active phases of many other projects such as road construction or the erection of a commercial building. Once the wells are completed and brought on production, the risks from dust and smoke are significantly reduced as most of the equipment that is the source of these emissions is no longer onsite.

Implementing mitigation measures like dust control, diesel exhaust filters, and fuel substitution can reduce particulate emissions. Dust control for PM_{10} can be as simple as a periodic water spray on dirt roads and well pads, and the use of particulate respirators for crews working near frack sand tanks and blenders. Many O&G wells are located in remote areas far from population centers, so broader mitigation measures are often not used, but for drilling in urban locations where air quality may already be compromised, mitigation is necessary.

A new technology called electric hydraulic fracturing or an e-frack uses natural gas-fired turbines to generate electricity that powers electric pumps. The process is much less polluting to the air than traditional diesel pump trucks and diesel generators, and also quieter for operations in urban areas. The natural gas fuel can often be supplied essentially “for free” from nearby, existing wells owned by the production company.

On the downside, the capital costs of e-frack equipment are approximately twice those of diesel. Some of this may be recovered by using natural gas-fired electricity to also supply power to the big triple rigs required to drill shale gas and tight oil directional wells. These rigs rely on electric-hydraulic systems to lift pipe, pump mud, and turn a drill bit. Switching from diesel pumps and generators to natural gas turbines for well pad electrical supplies would require an up-front expenditure to purchase the equipment, but once obtained it could be used at multiple well locations. Over time, it would substantially reduce operating expenses by substituting natural gas for expensive diesel fuel. It would also provide much lower emissions of $PM_{2.5}$.

Although production operations primarily emit NOx and VOCs (described below), the VOC emissions will form $PM_{2.5}$ from organic matter-based aerosols. These can be a significant component of PM exposure to populations near or downwind from O&G production areas (Buonocore et al. 2019). The VOCs can also react photochemically with the air to form ground level ozone, another health hazard.

5.2 VOCs, NOx and Fugitive Emissions

Shale gas and tight oil development activities can create measurable emissions of volatile organic compounds (VOCs), nitrogen oxides (NOx), and methane gas (CH_4). The sources of these vary from well pad to well pad (Pekney et al. 2014). NOx is typically emitted by internal combustion engines powering generators, drill rigs, and hydraulic fracturing pumps. Bringing natural gas, NGL, and petroleum to the surface during the production process can release methane, carbon dioxide (CO_2), and VOCs into the air from venting and flaring. Methane and VOCs may also escape from produced water stored in open tanks or impoundments on the surface (Butkovskyi et al. 2017).

"Fugitive emissions" is a term for natural gas and other hydrocarbon vapors that leak directly into the atmosphere from a wellhead or from surface infrastructure equipment such as compressors, pipelines, meter runs, etc. Fugitive emissions are distinct from "stray gas," which is the underground leakage of gas into a groundwater aquifer or some other receptor from a wellbore. Although often confused and sometimes used interchangeably, these are actually two separate phenomena with different causes, and stray gas is addressed in the next chapter on fracking and groundwater.

Fugitive emissions can be difficult to track and are often expensive to fix. It seems obvious that production companies would have an incentive to stop fugitive emissions, because they are losing product into the atmosphere that they could be selling. Unfortunately, the reality is that when gas prices are extremely low, the lost product isn't really worth all that much money. The cost of sending a crew out to fix leaks can actually be higher than the amount of product they save. There is of course a social responsibility to keep gas systems leak-tight, but many companies are more concerned about the bottom line. A Canadian study that surveyed fugitive emissions on production sites and informed operators of the location of gas leaks found in a follow-up survey taken a year later that only about a quarter of these leaks had been repaired (Ravikumar et al. 2019).

Methane gas occurs naturally at low levels in the atmosphere of around 10 ppm, and it can be difficult to measure small leaks against this background. A number of researchers have been monitoring the air near shale gas and tight oil drill sites in an attempt to quantify methane emissions, and also near established, conventional O&G fields (Pétron et al. 2014; Soeder and Kent 2018). It is not clear from these data if methane emissions from fracked shale wells are any more significant than those from older, conventional wells. There are, in fact, some concerns that older, conventional wells may have suffered deterioration of the cement and casing over time, leading to a loss in wellbore integrity and increasing the potential for gas leakage (Watson and Bachu 2009).

There are many sources of methane in the atmosphere, including anaerobic microbial digestion of organic matter and natural seepage from shallow coal seams or black shales. The isotopic signature of methane can be used to assess if the gas originated from biological activity (known as biogenic gas) or from the thermal breakdown of longer chain hydrocarbons over geological time into the simpler methane molecule (thermogenic gas). Thermogenic and biogenic gas can often be distinguished by their carbon isotope ratios. Stable carbon isotopes in thermogenic gas tend to be heavier than those in biogenic gas, because microbes prefer the lighter isotope, but other clues like the presence of noble gases are also used (Moore et al. 2018). Thermogenic gas may contain traces of longer-chain hydrocarbons like ethane and propane that are absent from biogenic gas (Claypool et al. 1980). Much of the isotope work on gas origins is now focused on determining the temperature of formation, which is cooler for biogenic gas and hotter for thermogenic gas (Stolper et al. 2015).

Thermogenic gas typically forms deep underground, and its presence in air can be an indicator of fugitive emissions from O&G operations. If ethane is found with methane, this can be a good indicator that the gas originated from O&G operations, because ethane does not have any natural atmospheric sources (Pekney et al. 2014). Along with thermogenic gas, “abiotic” methane gas can be created deep in the Earth’s crust through inorganic mineral reactions with water during a recrystallization process called “serpentinization” (Bradley and Summons 2010; Andreani and Ménez 2019). Tracking down fugitive emissions of natural gas is complicated and full of caveats.

One clear link between air pollution and fracking is a significant increase in VOC and NOx emissions measured at the national level between 2005 and 2015, which coincides with the development of shale gas and tight oil resources in the United States (Allen 2016). The onset of the shale boom resulted in many active drill rigs, more hydraulic fracturing operations, and new pipeline construction, gas plants, compressor stations, etc. Nationwide impacts from the sheer volume of all this infrastructure expansion are reflected in the air quality data.

VOC and NOx emissions into the atmosphere from O&G development come from two main sources: poorly functioning or malfunctioning equipment, and certain operational practices such as venting tanks or storing VOC-bearing produced water in open impoundments. Some of the VOC compounds, especially formaldehyde and benzene, may cause cancer or other adverse health effects and have been categorized as hazardous air pollutants by the U.S. EPA. It can be challenging to define the timing and duration of these pollution sources, especially on large shale plays where there may be many operators involved.

Sources of air pollution include organic gases and VOCs from the produced water, petroleum, and natural gas, VOCs and PM from the drilling and completion fluids, and NOx and PM from diesel and natural gas-fired internal combustion engines on the pad (Zielinska et al. 2014). Secondary ozone and PM pollution can be created by reactions among the organic gases and NOx (Nsanzineza et al. 2019). The sulfur content in diesel fuel or the produced O&G may result in sulfur dioxide (SO_2) or hydrogen sulfide (H_2S) emissions. NOx, SO_2, and PM can present both acute and chronic health risks, and as such are regulated by the U.S. EPA (Cohen et al. 2017). The five states with the highest health risks from these compounds based on population size and proximity to O&G operations are Texas, Pennsylvania, Illinois, California, and Oklahoma (Buonocore et al. 2019).

Emissions vary with the types of operations being performed at the well site. Even some time-limited activities, such as liquid off-loading, product transfer, and tank inspections can still result in significant emissions. One study found that liquid unloading events, which last only minutes, can produce methane emissions equivalent to those from a thousand routinely operating wells (Allen et al. 2015). Storage-related emissions resulting from product transfer and tank inspection may also contribute significantly to VOCs (Pétron et al. 2014). Even intermittent operations like flaring can be an important source of VOCs, NOx, and other hazardous air pollutants (Franklin et al. 2019). The introduction of new technologies and changes in operational practices may affect the magnitude of emissions over time.

The scale of shale resource development is so large that assessing air quality impacts can be challenging. Unlike PM, VOCs and NOx are gases and can therefore be dispersed widely across a shale play. The Marcellus play, for example, extends from the Kentucky-West Virginia border region up to the northeastern corner of Pennsylvania, a distance of some 450 miles (725 km). Production in the Bakken Shale covers an area of almost 60,000 square miles (155,400 km^2) in parts of Montana, North Dakota, Saskatchewan and Manitoba. Categorizing production activity and emission sources across such vast areas is difficult.

Fortunately for researchers, a small number of sites tend to contribute a major proportion of the emissions. These are known as "super-emitters," and once they are accounted for, the remaining emissions at multiple scales tend to be within the same order of magnitude, and can be averaged out for regional estimates (Allen 2016). Given the size of the shale plays, the number of operators, variability in site design, construction and maintenance standards, differences in operational approach, and variations in the oil and gas composition within and among plays, it is almost inevitable that there will be super-emitters among the crowd (Allen et al. 2017).

Linkages between energy production and energy use can also affect regional air quality, for example, gas production in Colorado's Wattenberg field coupled with wintertime gas use in nearby Denver (Ladd 2001). These impacts vary among regions (Allen 2016).

One way to obtain a better estimate of regional VOC and NOx emissions is to use computer simulations to run numerical calculations. Two different approaches can be taken; the first is a process-oriented approach called "bottom-up," which calculates representative emission rates from different sources multiplied by the number of sources in a study area (Allen 2014). These rates are then used to tally up the estimated total emissions from an operation or a set of operations (Townsend-Small et al. 2015).

The second approach is known as "top-down" and uses observation-oriented computer models of measured atmospheric concentration data to assign emission rates to individual sources within the model (Pétron et al. 2014; Nathan et al. 2015). The presence of super-emitters in the study area can contribute a significant degree of uncertainty to the estimates from either of these methods. The top-down estimates of fugitive emissions are typically higher than bottom-up estimates at the basin scale, with larger discrepancies in larger study areas (Vaughn et al. 2018). The variability in emissions over time when super-emitters are involved may explain much of the difference (Allen et al. 2017).

5.3 Background Emissions

Some shale gas and tight oil resources are located in remote, rural areas where little to no air pollution existed prior to development. The Bakken Shale in the sparsely-populated, northwestern corner of North Dakota is one such example. In this case, assessing the contribution of shale development to the degradation of air quality in the region is relatively straightforward and simple. However, other shale resources are located in areas that have existing, conventional O&G development, or near major cities like Dallas-Ft. Worth, Denver, or Pittsburgh. Defining the potential contribution of shale gas production to air pollution in the presence of all the other emission sources in these areas can be challenging (Pekney et al. 2018).

Many of the air contaminants linked to drilling and fracking, such as NOx, VOCs, DPM and others can also be sourced from automobiles, trucks, gasoline stations, and industrial processes. Only in cases where oil and gas development are especially intense, such as the Permian Basin in the Texas-New Mexico border region are emissions clearly related to hydrocarbon production. Satellite observations have in fact detected a "cloud" of NO_2, a surrogate for NOx, over the Permian Basin.

Methane emissions in particular can have both natural and anthropogenic sources that are difficult to separate. A study in the St. Lawrence River valley in Quebec near some Utica Shale production sites found four sources of methane in air (Pinti et al. 2016). These include the degassing of groundwater during processing for domestic or municipal uses, natural groundwater discharge along rivers, methane migration by seepage directly to the surface, and the degassing of recovered hydraulic fracturing fluids during flowback. Telling these sources apart can be quite challenging.

Several investigations sought to compare the concentrations of criteria air pollutants in areas with significant shale gas and tight oil production against existing data from the same location prior to development (e.g. Vinciguerra et al. 2015; Maskrey et al. 2016; Williams et al. 2018). This approach assumes that the background sources have remained constant over time, and any present-day spike in pollutants is due solely to shale development activities. This is not always the case, and accounting for the presence of other sources that could affect regional air quality is a major challenge (HEI 2019).

When historical data are not available, another strategy that can be used is to compare air pollution levels from a shale development area with a similar, reference location that does not have shale development (e.g. Rich and Orimoloye 2016; Garcia-Gonzales et al. 2019). This approach assumes the background sources in the reference location are essentially identical to those in the shale development area, which again may not always be the case. Care must be taken to separate out the shale-related pollution sources from everything else.

Air emissions from shale gas and tight oil development operations are complex, sporadic, and variable in terms of both concentration and composition. Every step of conventional and unconventional hydrocarbon development produces some degree of air emissions, which can originate from activities either on or off the well pad (Zielinska et al. 2014; Vaughn et al. 2018). Intermittent wellsite operations like pumping a hydraulic fracture treatment or temporarily throttling up a generator to drill through a difficult interval can create brief, high emissions (refer back to the photograph of a frack in progress in Fig. 2.1). These occur against a background of many hours of low emissions when equipment is slow or idle.

Different activities produce different emissions. For example, the highest emissions of $PM_{2.5}$, especially DPM, are most likely to occur when the diesel generators and pump trucks are used during the drilling and fracking process. NOx from internal combustion engines may also be high during this period. Once the well begins producing, emissions are more likely to consist of VOCs and methane from the produced water. Methane emissions at a Marcellus Shale research site were found to be highest during the initial production of flowback water (Pekney et al. 2018). Understanding air pollution in the context of daily operations taking place on the well pad is critically important for monitoring the air quality.

Many of the volatile chemicals associated with fracking are known, but others remain proprietary and trying to figure out what to measure in the air remains a major challenge. This is further complicated by reactions at high temperature and pressure between the fracking additives and rocks in the subsurface, which can return new chemical species in the produced water (Allen 2016). The measurement of air emissions from individual shale gas and tight oil production sites has been carried out at many locations using a variety of methods, including surrogates, tracer gases like acetylene, direct measurements of specific chemical compounds, and downwind plume monitoring (Nathan et al. 2015; Pekney et al. 2018).

Because of concerns over fugitive emissions, significant efforts have been focused on methane detection (Johnson et al. 2019). However, emissions of other compounds have been associated with shale gas and tight oil development, including VOCs, NOx, black carbon, PM, and radon gas (Casey et al. 2015; Goetz et al. 2017; Bari and Kindzierski 2018; Allshouse et al. 2019; Xu et al. 2019). Technology for the quantitative analysis of a wide variety of organic chemicals in the atmosphere is expensive, exotic, and not easy to adapt to the field. Thus, many air monitoring operations have been working to develop indicators, surrogates, or tracers that are more easily detectable (Pekney et al. 2018).

Chemical transport modeling is another approach for quantifying the possible links between chemical compounds in the atmosphere and potential O&G sources (i.e. wellsite flaring or a leaking compressor station). These mathematical models typically use measured chemical concentrations in air combined with meteorological data to try to define the movement of pollutants from sources to potential receptors in the surrounding populations (Pekney et al. 2018). Statistical techniques such as source apportionment modeling can be used in areas with background levels of pollutants to try to disentangle O&G emissions from other sources (Bari and Kindzierski 2018). The spatial and temporal variability in emissions complicates modeling, along with the subtle details of atmospheric transport at different scales. Another important consideration is that some of the significant sources are off-site, such as mobile emissions from heavy trucks transporting material to and from the well pad. More robust data sets needed for useful atmospheric chemical transport models include long and short-term variability in pollutant concentrations, documentation of a complete exposure pathway from source to receptor, and links that connect chemical concentrations at the source to concentrations in nearby communities where people might be exposed (Zielinska et al. 2014).

A study that combined air quality monitoring data with emissions, and used modeling to predict concentrations in air pollution exposure areas was undertaken on a regional scale in the Dallas-Ft. Worth area to assess effects from the development of the Barnett Shale (Zavala-Araiza et al. 2014). The investigation measured VOC concentrations hourly over a period of 20 months in an area of high shale gas development density, an urban location, and under background conditions. Publicly available VOC emission data from identified shale gas sources were used to predict the contributions of Barnett production to regional VOC levels.

The 20-month sampling campaign captured seasonal and operational variability, and collected data at relatively short (hourly) intervals over a large geographic area. The placement of samplers in locations with different types of land use allowed for background concentrations to be corrected, and the availability of an emissions inventory from a large number of sites provided detailed information on source types. The predictive model was parameterized with information about topography and meteorology, providing a useful approach for characterizing human exposure pathways. The results of the investigation indicated that VOC emissions have a low variability over time during the production phase of the wells, and that VOC emissions from the well pads were dominated by pneumatic devices used to control valves and other equipment. The variability in VOC concentrations was best explained by meteorology, rather than by episodic emission events (Zavala-Araiza et al. 2014).

The Wattenberg gas field near Denver, Colorado has been produced conventionally since 1970 (Ladd 2001). Regional air monitoring found substantial emissions of methane, VOCs, NOx and other criteria air pollutants in the area, and the investigation has evolved into a multi-institution, longer-term study of the environmental impacts from O&G operations along the Rocky Mountain Front Range (Pétron et al. 2012, 2014). This investigation was funded as a Sustainability Research Network by the National Science Foundation, and has produced more than 60 publications since 2014 (https://www.airwatergas.org/). Areas investigated include air, water, public health, and socioeconomic-political factors.

Although substantial air impacts have been documented from all different types of oil and gas production operations, it is not clear if air quality impacts from "fracking" are any worse or better than those from conventional O&G production. Many of the air emissions are from surface infrastructure, like leaking seals on compressors or vents on oil stock tanks, and these are the same for both conventional and unconventional well sites. Unconventional O&G uses hydraulic fracturing and so does some conventional O&G development. Air quality impacts appear to be similar and are not specifically related to the use or non-use of fracking. The intensity of the development seems to be more important than the specific method.

References

Allen, D. T. (2014). Atmospheric emissions and air quality impacts from natural gas production and use. *Annual Review of Chemical and Biomolecular Engineering, 5*, 55–75.

Allen, D. T. (2016). Emissions from oil and gas operations in the United States and their air quality implications. *Journal of the Air & Waste Management Association, 66*, 549–575. https://doi.org/10.1080/10962247.2016.1171263.

Allen, D. T., Sullivan, D. W., Zavala-Araiza, D., Pacsi, A. P., Harrison, M., Keen, K., Fraser, M. P., Hill, A. D., Lamb, B. K., Sawyer, R. F., & Seinfeld, J. H. (2015). Methane emissions from process equipment at natural gas production sites in the United States: Liquid unloadings. *Environmental Science & Technology, 49*(1), 641–648.

Allen, D. T., Cardoso-Saldaña, F. J., & Kimura, Y. (2017). Variability in spatially and temporally resolved emissions and hydrocarbon source fingerprints for oil and gas sources in shale gas production regions. *Environmental Science & Technology, 51*, 12016–12026.

Allshouse, W. B., McKenzie, L. M., Barton, K., Brindley, S., & Adgate, J. L. (2019). Community noise and air pollution exposure during the development of a multi-well oil and gas pad. *Environmental Science & Technology, 53*(12), 7126–7135.

Andreani, M., & Ménez, B. (2019). Chapter 15: New perspectives on abiotic organic synthesis and processing during hydrothermal alteration of the oceanic lithosphere. In B. Orcutt, I. Daniel, & R. Dasgupta (Eds.), *Deep carbon: Past to present*. Cambridge, UK: Cambridge University Press. https://doi.org/10.1017/9781108677950.

Banan, Z., & Gernand, J. M. (2018). Evaluation of gas well setback policy in the Marcellus Shale region of Pennsylvania in relation to emissions of fine particulate matter. *Journal of the Air & Waste Management Association, 68*, 988–1000.

Bari, M. A., & Kindzierski, W. B. (2018). Ambient volatile organic compounds (VOCs) in Calgary, Alberta: Sources and screening health risk assessment. *Science of the Total Environment, 631/632*, 627–640. https://doi.org/10.1016/j.scitotenv.2018.03.023.

Bradley, A., & Summons, R. E. (2010). Multiple origins of methane at the Lost City hydrothermal field. *Earth and Planetary Science Letters, 297*, 34–41.

Buonocore, J., Arunachalam, A., Reka, S., Yang, D., Lyon, D. R., Hull, H., O'Connell, R., Roy, A., Trask, B., & Michanowicz, D. (2019). *Air quality and health impacts of oil and gas emissions in the United States*. (Abstract) presentation A41D-07, AGU Fall Meeting, 9–13 December, San Francisco, CA, USA, American Geophysical Union.

Butkovskyi, A., Bruning, H., Kools, S. A. E., Rijnaarts, H. H. M., & Van Wezel, A. P. (2017). Organic pollutants in shale gas flowback and produced waters: Identification, potential ecological impact, and implications for treatment strategies. *Environmental Science & Technology, 51*(9), 4740–4754.

Casey, J. A., Ogburn, E. L., Rasmussen, S. G., Irving, J. K., Pollak, J., Locke, P., & Schwartz, B. S. (2015). Predictors of indoor radon concentrations in Pennsylvania, 1989–2013. *Environmental Health Perspectives, 123*(11), 1130–1137.

Claypool, G. E., Threlkeld, C. N., & Magoon, L. B. (1980). Biogenic and thermogenic origins of natural gas in Cook Inlet basin, Alaska. *AAPG Bulletin, 64*(8), 1131–1139.

Cohen, A. J., Brauer, M., Burnett, R., Anderson, H. R., Frostad, J., Estep, K., Balakrishnan, K., Brunekreef, B., Dandona, L., Dandona, R., Feigin, V., Freedman, G., Hubbell, B., Jobling, A., Kan, H., Knibbs, L., Liu, Y., Martin, R., Morawska, L., Pope, A. C., Shin, H., Straif, K., Shaddick, G., Thomas, M., van Dingenen, R., van Donkelaar, A., Vos, T., Murray, C. J. L., & Forouzanfar, M. H. (2017). Estimates and 25-year trends of the global burden of disease attributable to ambient air pollution: An analysis of data from the global burden of diseases study 2015. *Lancet, 389*(10082), 1907–1918.

Eisele, A. P., Mukerjee, S., Smith, L. A., Thoma, E. D., Whitaker, D. A., & Oliver, K. D. (2016). Volatile organic compounds at two oil and natural gas production well pads in Colorado and Texas using passive samplers. *Journal of the Air & Waste Management Association, 66*, 412–419. https://doi.org/10.1080/10962247.2016.1141808.

Franklin, M., Chau, K., Cushing, L. J., & Johnston, J. E. (2019). Characterizing flaring from unconventional oil and gas operations in south Texas using satellite observations. *Environmental Science & Technology, 53*(4), 2220–2228.

Garcia-Gonzales, D. A., Shamasunder, B., & Jerrett, M. (2019). Distance decay gradients in hazardous air pollution concentrations around oil and natural gas facilities in the city of Los Angeles: A pilot study. *Environmental Research, 173*, 232–236.

Goetz, J. D., Floerchinger, C., Fortner, E. C., Wormhoudt, J., Massoli, P., & Knighton, W. B. (2015). Atmospheric emission characterization of Marcellus shale natural gas development sites. *Environmental Science & Technology, 49*, 7012–7020.

Goetz, J. D., Avery, A., Werden, B., Floerchinger, C., Fortner, E. C., Wormhoudt, J., Massoli, P., Herndon, S. C., Kolb, C. E., Knighton, W. B., Peischl, J., Warneke, C., de Gouw, J. A., Shaw, S. L., & DeCarlo, P. F. (2017). Analysis of local-scale background concentrations of methane and other gas-phase species in the Marcellus shale. *Elementa Science of the Anthropocene, 5*, 1. https://doi.org/10.1525/elementa.182.

HEI (Health Effects Institute). (2019). *Human exposure to unconventional oil and gas development: A literature survey for research planning: Special report 2 (Draft for Public Comment)*: Boston, HEI-Energy Research Committee, 108 p. www.hei-energy.org

Horwell, C. J., Williamson, B. J., Donaldson, K., Le Blond, J. S., Damby, D. E., & Bowen, L. (2012). The structure of volcanic cristobalite in relation to its toxicity: Relevance for the variable crystalline silica hazard. *Particle and Fibre Toxicology, 9*, article no. 44. https://doi.org/10.1186/1743-8977-9-44.

Johnson, D., Heltzel, R., & Oliver, D. (2019). Temporal variations in methane emissions from an unconventional well site. *ACS Omega, 4*, 3708–3715.

Jones, J. B., & Segnit, E. R. (1972). Genesis of cristobalite and tridymite at low temperatures. *Journal of the Geological Society of Australia, 18*(4), 419–422. https://doi.org/10.1080/00167617208728780.

Ladd, J. H. (2001). Chapter 4: An overview and development history of the Wattenberg field. In D. S. Anderson, J. W. Robinson, J. E. Estes-Jackson, & E. B. Coalson (Eds.), *Gas in the rockies* (pp. 29–42). Denver: Rocky Mountain Association of Geologists.

Litovitz, A., Curtright, A., Abramzon, S., Burger, N., & Samaras, C. (2013). Estimation of regional air-quality damages from Marcellus shale natural gas extraction in Pennsylvania. *Environmental Research Letters, 8*, 1–8.

Luck, B., Zimmerle, D., Vaughn, T., Lauderdale, T., Keen, K., & Harrison, M. (2019). Multiday measurements of pneumatic controller emissions reveal the frequency of abnormal emissions behavior at natural gas gathering stations. *Environmental Science & Technology Letters, 6*, 348–352. https://doi.org/10.1021/acs.estlett.9b00158.

Maskrey, J. R., Insley, A. L., Hynds, E. S., & Panko, J. M. (2016). Air monitoring of volatile organic compounds at relevant receptors during hydraulic fracturing operations in Washington County, Pennsylvania. *Environmental Monitoring and Assessment, 188*, 410., 12 p. https://doi.org/10.1007/s10661-016-5410-4.

Moore, C. W., Zielinska, B., Pétron, G., & Jackson, R. B. (2014). Air impacts of increased natural gas acquisition, processing, and use: A critical review. *Environmental Science and Technology, 48*, 8349–8359. https://doi.org/10.1021/es4053472.

Moore, M. T., Vinson, D. S., Whyte, C. J., Eymold, W. K., Walsh, T. B., & Darrah, T. H. (2018). Differentiating between biogenic and thermogenic sources of natural gas in coalbed methane reservoirs from the Illinois Basin using noble gas and hydrocarbon geochemistry. *Geological Society, London, Special Publications, 468*, 151–188. https://doi.org/10.1144/SP468.8.

Nathan, B., Golston, L., O'Brien, A., Ross, K., Harrison, W., & Tao, L. (2015). Near-field characterization of methane emission variability from a compressor station using a model aircraft. *Environmental Science & Technology, 49*, 7896–7903.

Nsanzineza, R., Capps, S. L., & Milford, J. B. (2019). Modeling emissions and ozone air quality impacts of future scenarios for energy and power production in the Rocky Mountain states. *Environmental Science & Technology, 53*(13), 7893–7902.

Omara, M., Zimmerman, N., Sullivan, M. R., Li, X., Ellis, A., & Cesa, R. (2018). Methane emissions from 23 natural gas production sites in the United States: Data synthesis and national estimate. *Environmental Science & Technology, 52*, 12915–12925.

Pekney, N., Veloski, G., Reeder, M., Tamila, J., Rupp, E., & Wetzel, A. (2014). Measurement of atmospheric pollutants associated with oil and natural gas exploration and production activity in Pennsylvania's Allegheny National Forest. *Journal of the Air & Waste Management Association, 64*(9). https://doi.org/10.1080/10962247.2014.897270.

Pekney, N., Reeder, M., & Mundia-Howe, M. (2018). Air quality measurements at the Marcellus shale energy and environment laboratory site. *EM The Magazine for Environmental Managers*, August 2018, Air & Waste Management Association, 5 p.

Pétron, G., Frost, G., Miller, B. R., Hirsch, A. I., Montzka, S. A., Karion, A., Trainer, M., Sweeney, C., Andrews, A. E., Miller, L., Kofler, J., Bar-Ilan, A., Dlugokencky, E. J., Patrick, L., Moore, C. T., Jr., Ryerson, T. B., Siso, C., Kolodzey, W., Lang, P. M., Conway, T., Novelli, P., Masarie, K., Hall, B., Guenther, D., Kitzis, D., Miller, J., Welsh, D., Wolfe, D., Neff, W., & Tans, P. (2012). Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study. *Journal of Geophysical Research-Atmospheres, 117*(D4) 19 p. https://doi.org/10.1029/2011JD016360.

Pétron, G., Karion, A., Sweeney, C., Miller, B. R., Montzka, S. A., Frost, G. J., Trainer, M., Tans, P., Andrews, A., Kofler, J., Helmig, D., Guenther, D., Dlugokencky, E., Lang, P., Newberger, T., Wolter, S., Hall, B., Novelli, P., Brewer, A., Conley, S., Hardesty, M., Banta, R., White, A., Noone, D., Wolfe, D., & Schnell, R. (2014). A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin. *Journal of Geophysical Research-Atmospheres, 119*, 6836–6852.

Pinti, D. L., Gelinas, Y., Moritz, A. M., Larocque, M., & Sano, Y. (2016). Anthropogenic and natural methane emissions from a shale gas exploration area of Quebec, Canada. *Science of the Total Environment, 566-567*, 1329–1338.

Ravikumar, A.P., Barlow, B., Wang, J., & Singh, D. (2019). *Results of the Alberta methane measurement campaigns: New insights into oil and gas methane mitigation policy*. (Abstract) presentation A41D-08, AGU Fall Meeting, 9–13 December, San Francisco, CA, USA, American Geophysical Union.

Ren, X. R., Hall, D. L., Vinciguerra, T., Benish, S. E., Stratton, P. R., & Ahn, D. (2019). Methane emissions from the Marcellus shale in southwestern Pennsylvania and northern West Virginia based on 26 airborne measurements. *Journal of Geophysical Research-Atmospheres, 124*, 1862–1878.

Rich, A. L., & Orimoloye, H. T. (2016). Elevated atmospheric levels of benzene and benzene-related compounds from unconventional shale extraction and processing: Human health concern for residential communities. *Environmental Health Insights, 10*, 75–82.

Schwarz, J. P., Holloway, J. S., Katich, J. M., McKeen, S., Kort, E. A., & Smith, M. L. (2015). Black carbon emissions from the Bakken oil and gas development region. *Environmental Science & Technology Letters, 2*, 281–285.

Soeder, D. J., & Kent, D. B. (2018). When oil and water mix: Understanding the environmental impacts of shale development. *GSA Today, 28*(9), 4–10.

Stolper, D. A., Martini, A. M., Clog, M., Douglas, P. M., Shusta, S. S., Valentine, D. L., Sessions, A. L., & Eiler, J. M. (2015). Distinguishing and understanding thermogenic and biogenic sources of methane using multiply substituted isotopologues. *Geochimica et Cosmochimica Acta, 161*, 219–247.

Townsend-Small, A., Marrero, J. E., Lyon, D. R., Simpson, I. J., Meinardi, S., & Blake, D. R. (2015). Integrating source apportionment tracers into a bottom-up inventory of methane emissions in the Barnett shale hydraulic fracturing region. *Environmental Science & Technology, 49*, 8175–8182.

Vaughn, T. L., Bell, C. S., Pickering, C. K., Schwietzke, S., Heath, G. A., & Pétron, G. (2018). Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region. *Proceedings of the National Academy of Sciences, 115*, 11712–11717.

Vinciguerra, T., Yao, S., Dadzie, J., Chittams, A., Deskins, T., & Ehrman, S. (2015). Regional air quality impacts of hydraulic fracturing and shale natural gas activity: Evidence from ambient VOC observations. *Atmospheric Environment, 110*, 144–150. https://doi.org/10.1016/j.atmosenv.2015.03.056.

Watson, T., & Bachu, S. (2009). Evaluation of the potential for gas and CO_2 leakage along wellbores. *SPE Drilling & Completion, 24*(1), 115–126. (SPE 106817).

Williams, P. J., Reeder, M., Pekney, N. J., Risk, D., Osborne, J., & McCawley, M. (2018). Atmospheric impacts of a natural gas development within the urban context of Morgantown, West Virginia. *Science of the Total Environment, 639*, 406–416. https://doi.org/10.1016/j.scitotenv.2018.04.422.

Xu, Y., Sajja, M., & Kumar, A. (2019). Impact of the hydraulic fracturing on indoor radon concentrations in Ohio: A multilevel modeling approach. *Frontiers in Public Health, 7*, 76. https://doi.org/10.3389/fpubh.2019.00076.

Zavala-Araiza, D., Sullivan, D. W., & Allen, D. T. (2014). Atmospheric hydrocarbon emissions and concentrations in the Barnett shale natural gas production region. *Environmental Science & Technology, 48*(9), 5314–5321. https://doi.org/10.1021/es405770h.

Zielinska, B., Campbell, D., & Samburova, V. (2014). Impact of emissions from natural gas production facilities on ambient air quality in the Barnett shale area: A pilot study. *Journal of the Air & Waste Management Association, 64*, 1369–1383. https://doi.org/10.1080/10962247.2014.954735.

Chapter 6
Fracking and Water

Water issues related to fracking fall into two categories: water supply and water quality. Large, staged fracks can require millions of gallons of water, so the first concern is water supply, or more precisely water "availability," which refers to the allocation of water resources. Water supplies used for fracking can reduce the water available for human drinking water needs, or it can reduce the amount of water available in streams for aquatic ecosystems (Entrekin et al. 2018). Adequate drinking water supplies and minimum flows in streams must both be maintained.

Fracking does not require pristine water of drinking quality. Raw water from surface bodies is typically used on shale plays in wetter regions. In semi-arid locations like the Permian Basin of Texas and New Mexico, and in the Eagle Ford play near the Mexican border, undrinkable, brackish water from salty aquifers below the fresh groundwater supply is commonly used for fracking (Soeder 2017). Some companies have even considered using seawater for hydraulic fracturing. However, there are limits on the amount of TDS that can be tolerated in frack water, and if levels become too high, the performance of some chemical additives are inhibited.

The second concern is water quality, which can be at risk for contamination from the large volumes of chemicals used in hydraulic fracturing operations, the fluids returned to the ground surface from the well after fracking is completed, and the potential for toxic substances to leach into the groundwater from drill cuttings, drilling mud, and other materials left behind on the well pad (Soeder and Kent 2018). An additional worry for groundwater is the potential for "stray gas" to migrate into shallow aquifers from breached casing or cracked wellbore cement.

The main risks to surface water and groundwater quality have been identified as gas migration, contaminant transport through induced and natural fractures, wastewater discharge, and accidental spills (Vidic et al. 2013). Other researchers have identified similar risks, phrased slightly differently as stray gas in shallow aquifers, water contamination from spills or leaks of chemicals and shale gas wastewater, and accumulation of toxic and radioactive elements in soil or sediments (Vengosh et al. 2014; Lefebvre 2016).

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_6

The consensus view of a large group of North American hydrologists is that the most significant contamination risks from shale gas and tight oil development are stray gas migration in aquifers, and the potential for contamination of both groundwater and surface water from the chemical additives used for drilling, completion, and hydraulic fracturing (Soeder 2018). The flowback and produced water from the wells also contain these chemicals, along with other compounds from the geologic formation, including high levels of TDS, dissolved metals, radionuclides, and organics (e.g. Orem et al. 2014; Renock et al. 2016). A third potential risk is leachate from solid materials like black shale drill cuttings left on the surface that may also be a source of water contamination (Phan et al. 2015). Chemical contamination is thought to largely occur on the surface, rather than migrating upward from below. This places surface water bodies like streams and lakes at risk, and if the chemicals infiltrate into the ground and reach the water table, groundwater can be at risk also.

Water quality assessment often has the same problem as air pollution in distinguishing contaminants introduced by fracking from contaminants contributed by everything else. Many of the chemical substances added to or recovered from shale wells have also entered groundwater from a variety of other sources. A long legacy of conventional oil and gas development and other industrial activities on many of the landscapes that are now hosting shale plays has contributed a host of background water contaminants that are difficult to separate by source. The assessments can be complicated by the natural seepage of brine upward toward the surface at some locations, often accompanied by methane (Warner et al. 2012; Harkness et al. 2017).

Specific water quality indicators that would positively identify water contamination from a shale gas or tight oil well would be extremely useful, but so far none have been fully developed. Most people use an assemblage that includes high TDS, along with the presence of chloride, bromide, barium, strontium, and radium in the water (Brantley et al. 2014). This provides a clue, but it is far from definitive (road salt, for example, can supply many of these). Researchers have shown that certain strontium isotope ratios are indicative of produced water from the Marcellus Shale (Chapman et al. 2012). The application of this technique is complicated, expensive, and thus not used very often.

Several overarching documents have attempted to summarize the large number of publications addressing various aspects of water quality impacts from fracking, including reviews by the U.S. Environmental Protection Agency (USEPA 2016) and the Health Effects Institute (HEI 2019). These reports note that many studies have focused on monitoring surface water and groundwater contamination, while others have investigated the natural breakdown paths of spilled chemicals through reactive transport modeling. A few investigations have combined both.

Contaminants associated with shale gas and tight oil development that have been measured in groundwater, surface water, and produced water include inorganic chemicals, organic compounds, endocrine disruptors, and radioactive elements such as radium. A subset of studies also investigated the capture and residence times of chemicals in stream sediments, and the rates at which these may slowly introduce contaminants into surface waters for a time after a spill. Water quality investigations have been carried out in all of the major tight oil and shale gas producing regions of the United States, but the majority of studies were focused on the Marcellus Shale region, presumably because of the higher population density at risk of exposure compared to other plays.

6.1 Water Quality and Stray Gas

The perceived risk that gas and chemical additives injected into the ground during fracking operations would migrate upward and contaminate drinking water aquifers from below has been largely debunked (Fisher and Warpinski 2012; Hammack et al. 2014). It defies the laws of physics, because fractures simply don't break that way, and fluids don't move upward against gravity unless pushed. A hydraulically-induced fracture requires the overburden pressure to exceed rock strength if the fracture is to break vertically upward. In most cases, this occurs at a minimum depth of 2500 feet (800 m). Any hydraulic fracturing attempted at shallower depths will create fractures that propagate horizontally instead of vertically in a process known as "pancaking" that is very inefficient for O&G recovery.

Fracking is a very specialized and competitive business. Referring to the microseismic monitoring data presented back in Fig. 1.3, it is obvious that the vertical extent of the hydraulic fractures is limited, and they do not approach anywhere near the freshwater aquifers. Service companies carefully monitor the placement of hydraulic fractures within the target zone to limit costs and maximize hydrocarbon recovery.

The main thing working against frack fluids moving upward is gravity. A frack would literally have to be pumped way beyond design specifications to reach depths that even begin to bring it near shallow, freshwater aquifers. Once the pumps are stopped, fluids cease moving upward and gravity brings these down toward the horizontal well bore.

Although it has never been directly observed, a group of hydrologists decided to model every possible way hydraulic fracturing fluid might be able to move upward toward shallow aquifers (Birdsell et al. 2015). The migration mechanisms identified include topographically-driven flow, overpressured shale gas reservoirs, permeable pathways such as faults or leaky wellbores, increased formation pressures due to frack fluid injection, and the density contrast of the freshwater frack fluid with denser surrounding brine. The studies found that without a fast permeable pathway to the surface like a fault or an unsealed wellbore, the frack fluid would never reach shallow aquifers. These fluids would be trapped in the pore systems of overlying rocks by capillary imbibition as they migrated slowly upward. The modeling study concluded that in theory it might be possible for frack fluid to migrate upward and contaminate shallow drinking water aquifers, but to do so would require the convergence of a high number of unlikely circumstances (Birdsell et al. 2015).

Even with the presence of a high-permeability fault, significant overpressure in the shale, and fracking in the shale close to the fault, it would take nearly a thousand years for frack chemicals to reach shallow aquifers (Gassiat et al. 2013). Overpressure occurs in a rock when the pore system is isolated from hydrostatic pressure. The hydrostatic pressure gradient (water) is typically about half that of the lithostatic pressure gradient (rock), so overburden pressure is always greater than pore pressure. However, it is not unusual for the pore waters in deep formations to become separated from the water column to the surface. When this occurs, the pore pressure increases from hydrostatic to lithostatic and the rock is said to be overpressured. Gas shales are typically found to be overpressured when first drilled, but gas or oil production from the fracked well reduces this pressure to hydrostatic or lower fairly quickly. Once the well begins production, the pressure gradients in the formation direct fluid flow toward the wellbore, not toward the surface.

Although they might agree that it is not likely for frack liquids to migrate upward, O&G opponents have raised repeated alarms that stray gas might do so because of its buoyancy. Again, with fractures bending over to the horizontal at depths shallower than 2500 feet, there are few available flowpaths for vertical gas migration. Nevertheless, there does appear to be at least an empirical correlation between an increased frequency of stray gas incidents and the presence of shale gas wells (Li et al. 2016).

An analysis of 75,505 environmental compliance reports for 41,381 conventional and unconventional oil and gas wells in Pennsylvania found that shale gas wells have a six times greater risk of wellbore integrity problems compared to conventional wells (Ingraffea et al. 2014). This work showed a statistically-valid correlation between well type (conventional vs. unconventional) and the probability of cement/casing failure, but it did not go into details about the possible causes of this failure. It is also important to note that “wellbore integrity problems” do not necessarily translate directly into “stray gas.” Gas migration requires a source for the gas, a flowpath to the surface, and a pressure gradient to drive flow. Stray gas sources are often either the produced gas from the target formation, or gas occurring naturally in the shallower geologic units penetrated by the well.

Several modeling studies have shown that drilling the vertical top hole of a shale gas well using compressed air instead of a liquid drilling mud may affect pressure gradients within aquifers. Compressed air at pressures of up to 350 psi (2.4 MPa) entering confined or semi-confined aquifers can drive groundwater flow at rates that will entrain and mobilize existing methane gas, potentially causing stray gas migration (Geng et al. 2014; Zhang and Soeder 2016). Although compressed air drilling is faster and creates cleaner holes, many drillers have switched to liquid drilling fluids to reduce pressure effects on aquifers.

Canadian studies in northern British Columbia on gas migration from wells that were drilled horizontally but not fracked found that well construction quality was the most important determining factor for gas migration. Poorly constructed wells using inferior materials were much more prone to leakage and gas migration than wells that were installed properly (Sandl et al. 2019). Other studies have also noted that the presence of “problem wells” from poor construction seems to correlate more strongly than fracking with the occurrence of stray gas (Brantley et al. 2018).

A broader study of wellbore integrity problems from a wide range of countries including Australia, Austria, Bahrain, Brazil, Canada, the Netherlands, Poland, the U.K., and the United States found that published data on the integrity of well barriers are highly variable (Davies et al. 2014). Rates of well failure ranged from about 2% to as high as 75%. About 6.3% of the Marcellus Shale wells inspected in Pennsylvania between 2005 and 2013 were found to have wellbore integrity-related violations, including cement or casing failures, blowouts, and gas venting. Of the 143 actively producing wells in the U.K. included in the study, only one (0.7%) was found to have evidence of a well integrity failure (Davies et al. 2014).

Nevertheless, the question of why Ingraffea et al. (2014) found the risk of wellbore integrity problems in shale gas wells to be six times greater than conventional wells remains unanswered. Because the vertical topholes of horizontal shale wells and conventional wells are constructed and completed in more or less the same manner, the cause of greater wellbore integrity problems in shale wells is probably not related to construction practices or materials alone. Taking a step back to look at the bigger picture suggests that at least one major difference between conventional and unconventional wells is the amount of fracking.

Conventional wells penetrate the target zone vertically, and although some do not require fracking to be productive, many do. Vertical wells are typically fracked only once in the zone of interest (refer back to Fig. 2.3). The laterals of unconventional wells, on the other hand, are fracked dozens or even hundreds of times, depending on their length. The hydraulic fracturing fluid fills the production casing all the way to the surface, and the repeated pressurization and release during the frack stages may create cracks in the cement that is used to isolate the different casing strings. Because cement is strong under compression but weak in tension, the pressure fluctuations may result in the cement de-bonding from the steel casing, creating a small fracture called a microannulus. These can extend long distances vertically up a borehole and create a flowpath for gas migration (Soeder 2017). When a flowpath like a microannulus is present, modeling studies have shown that natural gas from depth can reach the surface in less than 2 days (Schwartz 2015). The formation of such microannuli may be responsible for the higher rates of wellbore integrity failure found by Ingraffea et al. (2014). Laboratory and field tests are required to define this problem and determine a solution.

Gas migration might also occur if a hydraulic fracture intercepts a pre-existing vertical flowpath like a fault or an abandoned well, providing a path upward for gas to reach shallow aquifers. Although such incidents are rare, the probability is not zero. A case was documented of a Marcellus Shale frack affecting an abandoned well in Tioga County, Pennsylvania in 2012. The incident occurred after East Resources had drilled and fracked a Marcellus Shale well on the Guindon farm in Union Township (Detrow 2012). The driller was aware that an old gas well was located less than a kilometer away. It had been completed in February 1932 by the Morris Run Coal Company, who drilled it to a depth of 5385 feet (1641 m) on a farm owned by a Mr. W.J. Butters. East Resources thought the old Butters well had been properly plugged with cement before being abandoned as required by state "plug and abandon" (P&A) regulations. It was not.

According to later analyses by the Pennsylvania Department of Environmental Protection (DEP), the frack from the Marcellus well on the Guindon farm did not directly connect with the Butters well, but "communicated" with it in terms of pressures. The investigation concluded that the Marcellus Shale drilling and fracking activity disturbed existing pockets of gas, which then migrated to the Butters well and began displacing water that had accumulated in the borehole over decades. The pressurized gas caused the well water to fountain some 30 feet (10 m) into the air (Fig. 6.1).

The geyser was brought under control after the Marcellus operator reduced gas pressure in the shale formation by flaring. Once the water stopped flowing out of the Butters well, it was filled with cement and properly plugged. This incident brought to light the problem of legacy abandoned wells in areas that are being re-explored for shale gas and tight oil. Pennsylvania has literally hundreds of thousands of such

Fig. 6.1 An abandoned well discharges a 30-foot (10 m) geyser of water after communicating with a Marcellus Shale hydraulic fracture in 2012. (Source: National Public Radio, StateImpact, public domain)

abandoned wells, which are present anywhere people drilled for oil and gas, extending clear back to 1859 and our old friend Colonel Drake. Most of these older wells are not in state well records, which were not established until after the Second World War, and many have not been located. Quite a few still leak significant amounts of methane into the atmosphere (Kang et al. 2014, 2016).

The U.S. Department of Energy has employed magnetic survey techniques and methane sensors to try to locate abandoned wells in urban areas, but the presence of other infrastructure can interfere with and complicate the measurements (Hammack and Veloski 2016). For larger areas such as developed oil fields in places like Wyoming, magnetic booms deployed from helicopters have been used with a degree of success (Hammack et al. 2016). The magnetic survey reacts to steel and iron casing remaining in the ground from abandoned wells, even if casing was cut off level with the surface, and the well was subsequently overgrown and buried. This was common practice on abandoned wells, and a significant amount of digging into the center of magnetic anomalies is often required to actually locate the old wells. Many abandoned wells also had the casing pulled to meet the high demand for steel during the Second World War. Although it was feared initially that this would compromise the magnetic surveys, researchers discovered that the void spaces in the Earth remaining from the uncased wells often register as magnetic anomalies on the surveys, allowing the boreholes to be found (Hammack et al. 2016).

Modern regulations were not put into place for how to properly P&A a well until the second half of the twentieth century, and many older wells were abandoned rather creatively. A common technique in the Appalachian Basin back in the day was to stuff a small pine tree down the borehole pointy end first, and then shovel in dirt on top of it. (An 1881 Pennsylvania state regulation actually specified the use of a "tapered wooden plug," which could be argued is a pine tree). Although this served to hide an old well, it did not provide much of a pressure barrier. In other cases where modern P&A practices were carried out, bridge plugs were sometimes not set properly or poor-quality cement was used.

Although state regulators do commonly provide oversight of the plugging operations, shortages of personnel rarely allow inspectors to visit sites after the well has been plugged. For many operators, proper P&A is a professional duty, but to others it is just a needless expense that must be taken care of as cheaply and quickly as possible. Unfortunately for shale well drillers, the long history of O&G drilling in the United States means that they could encounter a wide variation in the quality of P&A wells in the neighborhood.

Finding definitive links between stray gas and fracking has been challenging. Data mining of groundwater chemistry information from Pennsylvania townships where methane contamination had been reported provided some indications that methane concentrations are higher in groundwater near gas wells and along faults, but the results were far from conclusive (Li et al. 2016). Studies in northeastern Pennsylvania suggest that local geological conditions may also play a role, and that pre-existing structures and fractures in certain locations may allow methane to migrate upward more easily (Woda et al. 2018).

Part of the problem has to do with the complicated origins and migration of stray gas in aquifers. As described in the previous chapter, biogenic methane can be generated by microbial processes in soils and shallow aquifers, and thermogenic methane comes from organic-bearing rocks like coal or shale exposed to high temperatures during their burial history. Thus, stray gas can form within the aquifer from biological activity, enter groundwater from a compromised wellbore that extends kilometers deep into shale, or seep in from an organic-rich rock unit lying directly beneath an aquifer. In many cases, gas from more than one origin will be present in an aquifer, and the sources are sometimes indistinguishable.

A second part of the problem is related to how the data are collected for assessing the presence of gas in groundwater. It is important to note that amount of methane that dissolves in water, like carbon dioxide, is pressure-dependent. Just as soda water will release bubbles when a bottle is uncapped, groundwater will release methane when pressure is reduced. Depending on where in the water system a sample is collected: downhole, at the pump, or at the tap, the methane content can be significantly different. A lack of uniformity on where and how samples have been collected makes comparisons between different studies challenging, although several groups are working on standardizing stray gas sampling and analysis methods.

This risk and the concern of stray gas is the potential for methane to be released in air. Methane dissolved in water is nontoxic and not hazardous. However, pumping a well reduces the pressure in an aquifer, which can result in methane gas exsolving out of the groundwater and being released into the air. If it becomes trapped in a confined space and reaches concentrations between the lower and upper flammability limits of 5–15%, it may combust in a slow-motion explosion called a deflagration. There have been more than a few instances where stray gas has accumulated in a basement or well vault and exploded, causing property destruction, injuries, and even fatalities (Baldassare et al. 2014).

The dissolved methane content in groundwater from domestic water wells is routinely measured by shale drillers as part of a pre-drilling baseline survey conducted on drinking water supplies within a radius of a kilometer or so from the shale well site. This is done as a legal defense by the drilling industry to document existing contaminants in groundwater prior to drilling. If landowners seek compensation for contamination of drinking water supply wells from “fracking,” the operators can show that the contaminants often originated from other sources unrelated to the gas well. Some states such as Pennsylvania have long required baseline groundwater quality measurements as part of the drilling permit, but most operators now collect it everywhere for liability protection.

There are a staggering number of existing or “legacy” contaminants in groundwater, including stray gas from natural sources, spilled fuel and other oily chemicals like paint or motor oil, gasoline from leaking underground storage tanks, industrial wastewater, pesticides and fertilizers applied to agricultural fields, chemical waste buried in pits and trenches, and a host of others. The data collected by shale drillers on pre-existing chemicals in the groundwater are shared with the water well owners so that everyone knows what is and is not present in their aquifers. Most groundwater groups and county health agencies urge people to have their domestic wells tested annually. Few do. The data from the water analyses showed a lot of people that there were contamination issues with their drinking water that pre-dated any fracking in the neighborhood. It should be noted that in areas with intense shale gas development and close well spacing, frack chemicals from previously-developed, nearby shale wells could be in the "pre-drilling" groundwater samples. Teasing these out of the data sets has been very challenging (Siegel et al. 2015).

Some landowners have tried to collect financial benefits from shale drillers despite knowing that the gas in their groundwater was not caused by fracking. One of the best-known cases occurred near Dallas-Ft. Worth in Parker County, Texas, where the landowners claimed that a Barnett Shale well adjacent to their property was responsible for introducing methane gas into their water well (Pope 2012).

This was in the early days of the shale boom, and the operator had not collected a pre-drilling baseline sample, which was not a permit requirement in Texas at the time. Nevertheless, the driller was certain that the gas was not from the Barnett and the company refused to pay. The regional EPA office and the Texas Rail Road Commission (TRRC) became involved. (The TRRC is the state agency in Texas that oversees oil well permitting and drilling.) The two agencies disagreed on how to deal with the problem and the Barnett well was ordered by the EPA to be shut-in until the case was settled.

The operator ran chemical analyses on gas samples collected from both the Barnett well and the landowners well. The gas chemistry analysis showed that the nitrogen and carbon dioxide content of gas from the landowners well were completely different from the gas chemistry in the Barnett well. The gas sample from the landowners well did closely match the chemistry from a gassy sandstone unit located directly beneath the water supply aquifer. This rock formation was producing commercial amounts of gas from conventional wells located relatively close to the landowners' property. The regulatory agencies concluded that the water well had been drilled a little too deep when first constructed and penetrated the top of this gas-bearing formation, which was leaking gas into the groundwater. The much deeper Barnett Shale was obviously not the source, and the operator was cleared of all blame.

Things got rather ugly a bit later on when attorneys for the operator discovered that the landowners had known about the presence of gas in their water well long before the Barnett well was drilled. (Helpful tip: anything posted on social media remains there forever.) They had been trying to obtain some easy money on the advice of a consultant, who assumed the company would simply pay off the landowners to avoid the costs of a legal conflict. Truth be told, this had happened often enough in the past. This time, however, it backfired and the operator sued the landowners for the revenue lost while the Barnett well had been shut in.

This case set a significant legal precedent in the shale gas and fracking business. In the early days of the shale gas boom, operators would routinely pay off any random claim of environmental damage without an investigation. It was cheaper and faster than engaging lawyers and having the whole thing go to court. However, after the Parker County incident, industry woke up to the fact that some people were taking advantage of this policy. Whether or not the permit required it, companies began to routinely collect baseline water quality data from all domestic water wells within a kilometer or so of a well pad prior to drilling.

One other benefit of the baseline water testing is that it largely did away with the non-disclosure agreement (NDA). Signing one of these was a standard requirement for industry to pay off a claim of environmental damage from fracking. Because of the NDAs, it was impossible for researchers to learn any details about what had happened, reconstruct the probable causes of incidents, and understand the impacts to the environment. It was like trying to investigate an airplane crash with no radar data, no air traffic controller tapes, no cockpit voice recorder, no witnesses, and no survivors. NDAs are probably better known for their use in sexual harassment settlements to keep victims from talking. These instances also have been criticized because while an NDA may protect a company's reputation, it also leaves new employees unaware that there had ever been a problem.

Another well-known case attributed to stray gas is a water well vault that ruptured in Dimock, Pennsylvania on New Year's Day 2009. No one actually observed the incident taking place; the homeowner discovered it when she returned home later in the day. Almost immediately, the media sensation surrounding the event resulted in the foregone conclusion that Marcellus Shale gas drilling in the area had somehow caused a methane explosion inside the well vault. Dimock has reached almost mythological status among protestors as an example of wanton environmental destruction by greedy O&G production companies.

State investigators found evidence that supported groundwater impacts associated with wellbore integrity problems at Dimock. This was primarily true for many wells that were drilled early in the play's history and constructed with minimal barrier elements, including open-hole completions. Although the NDAs kept most of the information under wraps, the operator initially supplied bottled water and then installed new water systems for everyone in the neighborhood without explicitly accepting blame. Intermediate casing strings have been run in newer wells to isolate gas-bearing shallower rocks from overlying aquifers. Whatever happened at Dimock was complicated and not well understood. When events like this are picked up by the media, however, the nuances and details are often glossed over or ignored.

Methane explosions are a deflagration; these burn much more slowly than the supersonic detonations and shock waves associated with dynamite or military-grade explosives like C-4. Deflagrations will often lift a building straight up off its foundations until the pressure escapes, and then drop it back into place. This happened when stray gas from a badly-cemented conventional well in Geauga County, Ohio seeped into the basement of a nearby home in 2007 (Bair and Tomastik 2012). The foundation was damaged, but the house remained intact.

Some researchers have concluded that the observed damage at Dimock is not consistent with a natural gas explosion (Engelder and Zevenbergen 2018). The lid of the vault was concrete slab that had been split into three pieces and overturned, but it was unmarked by soot or any other sign of a flame. In addition, no credible ignition source was found inside the vault. Calculations showed that the pressure needed to lift the concrete slab was roughly 0.3 bar (4.35 psi), but the pressure required to break it into three pieces and overturn these was considerably higher.

The actual cause of the damage remains unknown. The ground was frozen solid with little snow cover and no one claims to have witnessed the event.

Baseline data from drinking water supply wells has been used in three classic and mutually contradictory studies of stray gas in groundwater. Duke University claimed to have found that methane concentrations in northeastern Pennsylvania groundwater increase with decreasing distance from a shale well (Osborn et al. 2011). GSI Environmental and Cabot Oil & Gas analyzed a larger number of samples from the same general area and concluded that the methane content of groundwater was related to topography (lowest in highlands, highest in valleys), not the location of gas wells (Molofsky et al. 2013). A third study by Syracuse University and Chesapeake Energy used a massive database of water well baseline data from the same region and found no statistical correlation between proximity to shale gas wells and methane in groundwater (Siegel et al. 2015).

In a related study, Yan et al. (2017) looked at inorganic dissolved solids in groundwater samples from this same region, including Ca, Na, Mn, Fe, Cl, and SO_4. Groundwater near shale gas wells located in valleys was significantly higher in these constituents than valley groundwater farther from wells, and groundwater from upland areas had lower dissolved solids than valley samples. The authors speculate that valleys experience a greater mixing of shallow and deep groundwater, possibly triggered by the shale gas development process. However, earlier studies by Warner et al. (2012) concluded that the higher salt content in valley groundwater was a natural occurrence, as was the higher methane content. The number of samples matters–too many may dilute any contamination signal from a gas well and make it hard to distinguish these events from background (Brantley et al. 2014). The possible links between groundwater quality and proximity to fracked shale wells are complicated, confusing, and remain unsettled.

Substantial amounts of baseline water quality data from drinking water supply wells are available thanks to the shale boom. Just because these measurements exist, however, it does not mean that they are necessarily useful for stray gas migration studies. Part of the problem is that the data are collected pre-drilling, so if any gas migration occurs after the well is drilled and fracked, it won't be measured. In fact, the study by Siegel et al. (2015) recognized this issue and used a massive amount of data from more than 11,000 wells to have a high enough sample density for at least some of the "pre-drilling" analyses to provide "post-drilling" data from other nearby shale wells that had already been fracked.

A second data concern for stray gas and other water quality investigations using drinking water wells is that because these wells are pumped, and are often uncased through the aquifer they might draw in contaminants from anywhere that could never be linked to a fracked well. These open-hole completions randomly mix water from the different aquifer flow zones inside the borehole, making it extremely challenging if not impossible to trace flowpaths for stray gas or other contaminants. However, the thousands of domestic water wells near shale gas and tight oil development sites that are being sampled routinely by the drilling companies for legal protection are pretty much the only option available for data.

Stray gas has become a “new” groundwater hydrology problem, drawing attention away from “classical” water-soluble contaminants like gasoline, diesel fuel, and chlorinated solvents. Many hydrologists in the water resource community are attempting to address stray gas issues, and several groups have recommended that dedicated groundwater monitoring wells equipped with multilevel samplers to isolate specific flow zones be installed near shale gas wells (e.g. Jackson et al. 2013; Council of Canadian Academies 2014; Soeder 2018). This has not been carried out at any significant scale as of this writing, because industry has largely refused to cooperate with environmental monitoring studies, especially those related to groundwater. Researchers continue to try to find methods to tag stray gas and trace it back to a point of origin (Larson et al. 2018).

The single “prospective” groundwater study carried out so far in the United States has been by Yale University researchers in cooperation with Southwestern Energy on Marcellus Shale development activity in northeast Pennsylvania (Barth-Naftilan et al. 2018). Several groundwater monitoring wells were installed prior to Marcellus Shale drilling, and monitored through the drilling, fracking, and production process. Some pressure transients and methane fluxes in the groundwater were seen that could generally be linked to drilling operations, including a rupture in the production casing that introduced gas to the aquifer until it was repaired. A gradual increase in groundwater methane concentration was measured on at least one monitoring site near a shale well over an extended time period, but the isotopic signature of the gas was biogenic in nature, not thermogenic as expected from the Marcellus.

Canadian studies in British Columbia have been using long term soil gas flux meters to measure methane and CO_2 emissions as these gases migrate through soil (Forde et al. 2019). Methane fluxes through soils can migrate along preferential pathways and come to the surface long distances from the wellbore. The Canadian investigators were even able to inject methane into the unsaturated zone of the soil to track gas migration and found that changes in barometric pressure greatly influence flow, at least for low-pressure gas migration. These barometric pressure effects may help explain some of the variability of stray gas migration near well sites.

A site in Canada located at Canadian Forces Base Borden northwest of Toronto has been used since 1978 for controlled field experiments of groundwater contamination (Cherry et al. 1996). Industrial chemicals were carefully released into the shallow subsurface and detailed monitoring tracked their movement and fate. A methane injection experiment was carried out in 2017 at this extremely well-characterized site to investigate stray gas migration (Cahill et al. 2017). The methane was injected at two well points in the shallow sand aquifer at Borden and tracked. Unexpected, strong lateral movement of free gas was observed, along with dissolved gas dispersion in the direction of gas flow. Hydrochemical impacts from the methane persisted for over a year after injection. If nothing else, this field experiment clearly demonstrated that stray gas is complicated.

6.2 Additives and Produced Water

Some of the chemicals added to frack fluid are relatively benign, such as ethylene glycol used for corrosion control or polyacrylamide added as a friction reducer, but others are not. For example, the biocides added to control downhole bacteria growth are definitely something that one does not want to encounter in drinking water.

At least four sources of chemical contaminants associated with the development of tight oil and shale gas may present water quality risks to groundwater and surface water. These are, in approximate chronological order of use:

1. The various drilling fluids, lubricants, cement compounds, and "drilling mud" employed when constructing the borehole (Soeder and Kent 2018).
2. The concentrated chemicals, conditioners, and performance enhancers stored on the well pad in large volumes and blended into the frack fluid (Soeder et al. 2014).
3. The fluids produced out of the well after fracking, including flowback of the original frack fluid and water produced from the formation itself. Produced water consists of high TDS brine, hydrocarbons, dissolved solids like barium extracted from the rock (Renock et al. 2016), and new chemicals formed by downhole reactions between the frack fluid additives and the formation (Orem et al. 2014).
4. Black shale drill cuttings, drilling mud residue, contaminated soil, and other solids left behind on the drill pad that may oxidize, weather and leach inorganic and organic chemicals, heavy metals, radionuclides, and other potentially toxic substances into shallow groundwater (Phan et al. 2015).

The contamination risks to water from the frack chemicals are poorly defined, because little is known about the natural breakdown paths of the different organic chemical additives in groundwater, or the persistence of inorganic compounds in streams. A few natural attenuation (NA) lab studies have been done with microcosms using analog mixtures of organic chemicals to represent "typical" frack fluids (e.g. Cluff et al. 2014). A few reactive transport modeling studies have been done to try to define NA pathways, but with little more than generalities available on the chemical additives, these have not been very useful (HEI 2019). Much remains unknown given the number of possible chemical additives, the variety of new chemicals constantly being introduced, and the proprietary nature of the formulations.

After a broken pipeline spilled produced water from the Bakken Shale into a North Dakota creek, the USGS found itself conducting an impromptu field experiment to measure the dilution and dispersal of inorganic dissolved solids in a stream. The general consensus was that contaminants from a surface water spill would dissipate fairly quickly after an incident because the pollutants are rapidly washed downstream. Surprisingly, the USGS found that measurable levels of contaminants were still present in the stream 6 months after the pipeline break had been repaired. The contaminants had become trapped in the stream sediment, and were slowly diffusing into the water over time (Cozzarelli et al. 2017).

Investigations by the USGS of groundwater overlying prominent shale gas and tight oil production regions in the U.S. found no evidence of widespread aquifer contamination from fracking, although they did find isolated incidents of groundwater contamination that they concluded were from surface spills. However, many of the contaminants that were found pre-dated the shale development in the area, and were from earlier spills or leaks. The USGS studies focused on determining both the origin of the contaminants and the age of the groundwater (i.e. when it entered the aquifer as recharge). The two analyses together created a more complete picture of how and when the aquifer might have been contaminated.

Some notable findings from the series of USGS groundwater studies include the following: Groundwater methane in the Bakken Shale development region of North Dakota was sourced primarily from the lignite (brown coal) located high above the Bakken in the stratigraphic section (McMahon et al. 2015). Other sources of contamination from the long history of oil and gas development in California essentially masked any potential groundwater impairment caused by recent fracking activities (McMahon et al. 2016). Aquifer studies in Arkansas, Louisiana, and Texas above the Fayetteville, Haynesville, and Eagle Ford shale plays found that methane in the groundwater was mostly biogenic in origin (McMahon et al. 2017).

A comparative investigation of aquifers in upland areas across the Pennsylvania-New York border region found very similar groundwater chemistries among the 50 wells sampled. Marcellus Shale gas is being produced only in Pennsylvania because New York has a fracking ban in place. One well contained thermogenic methane from a shallow geological source that may have been mobilized by nearby fracking activity. Another contained benzene, a component of gasoline, but the water sample had recharged prior to the beginning of shale gas development in the region, and the contamination was from an older spill (McMahon et al. 2019).

The largest investigation and review to date on the potential impacts of fracking on water resources in the United States is a 664 page report published by U.S. EPA Office of Research and Development in 2016 at the conclusion of a five-year investigation (USEPA 2016). The goal of this study was to assess the risks to groundwater supplies (identified as Underground Sources of Drinking Water or USDW by the EPA) from hydraulic fracturing operations. The project hosted a number of technical workshops to obtain input from the O&G industry, research scientists from other federal and state agencies, environmental advocacy groups, and interested citizens. An extensive compilation of existing scientific literature was gathered up, and a number of field and laboratory investigations were carried out. The results were assembled into a nearly 1000-page draft report in 2015 that was published as a final report a year later after receiving detailed peer reviews. The EPA study concluded that although fracking can cause individual groundwater contamination incidents, primarily through surface spills, the evidence did not support concerns that fracking was systemically contaminating shallow aquifers on a widespread basis. No one so far has published any data that contradict this.

The EPA study identified 1606 chemicals associated with hydraulic fracturing, including 1084 chemicals used in hydraulic fracturing fluid and 599 chemicals detected in produced water (USEPA 2016). Although only about a half-dozen chemical additives are used in any individual frack, the EPA discovered that a bewildering variety of choices are available. With new chemicals constantly being added, it is virtually impossible to track them all, or even to just stay up-to-date. The identity of many of these chemicals was unknown, with formulas and physical property information tightly held by the manufacturers as proprietary trade secrets. The hydraulic fracturing fluid chemical additives that were identified had virtually no information available on toxicity or other potentially hazardous properties of the compounds. The fact that these various chemicals with unknown properties may be entering the environment is a concern.

The O&G industry has been resisting the disclosure of frack chemicals for years. With the strong support of then Vice President Dick Cheney, the 2005 Energy Policy Act as approved by Congress and signed into law by President Bush contained a provision that exempted hydraulic fracturing service companies from compliance with the Underground Injection Control (UIC) program requirements of the Safe Drinking Water Act (SDWA). Most UIC wells are used for the disposal of chemical waste, and the intent of the rule was to make sure public records were being kept for the disclosure of all chemicals being injected underground.

Shale wells are not UIC disposal wells, but fluids are injected underground and service companies were concerned that a narrow reading of the law could require them to publicly disclose the secret chemical formulas of proprietary frack chemical additives being developed for shale. Competitors could then access and copy these special formulas. The companies wanted the UIC rules modified to make it crystal clear that they were exempt from revealing their secret frack formulas. Known as the “Halliburton loophole” after Cheney’s former employer and the largest hydraulic fracturing service company in the U.S., the exemption is only for the UIC requirements of the SDWA. It does not exempt industry from the entire SDWA or the older Clean Water Act as some people have claimed. (More information is available at https://www.epa.gov/uog).

The United States has historically protected the trade secrets of companies that develop a proprietary formulation or an industrial process, and service companies invest a lot of time and money into developing hydraulic fracturing fluid formulations. Like the formula for Coca-Cola, fracking companies claimed the right to keep their mixtures secret. While this is understandable, the large volumes and potential environmental hazards of frack fluid additives can have a much larger impact than a spilled bottle of Coca-Cola, so perhaps at least the toxicity and hazardous properties data should be made available. The oil and gas industry has been exempted from a number of federal environmental statutes for quite some time, for example the requirement to obtain an NPDES permit (National Pollutant Discharge Elimination System) for storm water discharges. So although the Halliburton loophole raised concerns within the environmental community, by and large the O&G industry couldn’t see what all the fuss was about.

The EPA drinking water study (USEPA 2016) also found that some activities associated with hydraulic fracturing were more likely than others to have significant impacts on water resources. These are listed below:

- water withdrawals in areas with limited water resources

- surface spills of hydraulic fracturing fluids, chemicals, or produced water
- contamination of shallow aquifers by injection of hydraulic fracturing fluid into wells with wellbore integrity problems
- discharge of inadequately treated wastewater directly to surface waters
- the use of unlined pits for wastewater storage or disposal.

For each activity, a number of alternative practices were identified that could reduce the frequency and severity of potentially negative effects on water resources from fracking. For example, storing drilling fluids, chemicals, and wastewater on drill pads in steel tanks rather than leakage-prone unlined pits would greatly reduce the risks of off-site migration (Fig. 6.2).

The EPA study identified a number of data gaps where future research could be focused. Prominent among these is a need for better geographical information on the location of fracking activities with respect to drinking water supplies. Other data

Fig. 6.2 Photograph of a dark substance identified as drilling mud oozing out of the ground below a drill pad in Harrison County, West Virginia, in 2010. (Photo by adjacent landowner Doug Mazer, used with permission)

gaps include the absence of pre-drilling baseline data and the resulting difficulty of separating out the potential impacts of fracking from other legacy sources of groundwater contamination, which align with the findings of similar studies (e.g. Soeder et al. 2014). The EPA also found that there are significant challenges in understanding the migration of contaminants in the subsurface, as noted in other assessments (e.g. Cahill et al. 2017). Finally, like many other would-be investigators, the agency ran into difficulty securing industry cooperation for access to well sites, samples, and data (Soeder 2015).

Concerns raised by the Halliburton loophole and the EPA study led to an effort in the U.S. Congress and in state agencies charged with issuing drilling permits to require the public disclosure of frack chemical additives. A joint venture between the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission established a website called FracFocus (http://fracfocus.org/) that contains well completion reports and a listing of the chemicals used for hydraulic fracturing indexed to a map. The posting of frack additives on FracFocus was voluntary at first, but a number of states now require this as part of the well permitting or completion process.

The main ingredients of hydraulic fracture fluid, as reported on FracFocus, are typically water, sand as proppant, polyacrylamide to make friction-reducing slickwater, guar gum to thicken the fluid to carry the proppant, hydrochloric acid for cleanup, ethylene glycol for corrosion resistance, and a biocide to control downhole bacteria that can create sour gas. Some fracking opponents have claimed that service companies were injecting a complex chemical soup into the ground consisting of hundreds of unknown and exotic compounds. It turned out instead that the basic chemicals used for a hydraulic fracturing job were actually fairly simple and cheap. However, by not making this information available from the beginning, the O&G industry allowed fracking opponents to dictate the narrative, and they filled a dark closet with every monster imaginable. Despite the availability of FracFocus and other information on chemical additives since 2012, many of these myths still linger. The industry certainly does try different variations of chemicals to get the formulation right for a particular part of a particular shale play, but nobody routinely uses hundreds of chemicals on a single job.

Although the large study done by the EPA (USEPA 2016) concluded that chemical additives from hydraulic fracturing activities are not systemically contaminating groundwater, this is not to say that contamination incidents don't happen. They certainly do, but on an individual water supply well basis. Water samples from 64 private residential groundwater wells in northeastern Pennsylvania and in southern New York were collected between 2012 and 2014 to look for organic compounds that potentially originated from shale wells (Drollette et al. 2015). Along with an assortment of VOCs, in two of the well water samples the investigators detected bis(2-ethylhexyl) phthalate, a known additive to frack fluids. They concluded that the source of the chemical was probably surface spills of frack additives on nearby drill sites.

In addition to surface spills, there is a potential for hydraulic fracturing fluids, flowback water, and produced water to be released directly into a shallow aquifer through a compromised well casing or a poorly-executed cement job. These incidents are quite rare, however, with only ten documented as of 2017 among the thousands of wells completed in the Marcellus Shale (HEI 2019). One of the best known cases was the reported 2015 contamination of several domestic water supply wells in Pennsylvania following the drilling and fracking of five Marcellus Shale wells within a distance of 2 km (Llewellyn et al. 2015). Stray gas and a foaming agent were reported in the water wells, and laboratory analysis detected the presence of 2-n-butoxyethanol, a surfactant commonly used in hydraulic fracturing fluid. The shale wells had been completed without intermediate casing, and the frack fluids were thought to have moved vertically up the borehole until encountering a natural fracture system in the uncased interval that allowed them to migrate into the aquifer.

The produced water from shale gas and tight oil wells is often hypersaline with very high levels of TDS. The TDS is typically composed of chlorides, bromides, sodium, calcium, magnesium, barium, strontium, and other salts. Produced water also commonly contains the radioactive element radium (Ra), and natural gas from these formations often contains the radioactive gas radon (Rn). USGS publications on the Ra content in produced water from Marcellus Shale wells (Rowan et al. 2011) and a companion report on Rn in Marcellus Shale natural gas (Rowan and Kraemer 2012) show that these radionuclides have been known about for quite some time, but they are occasionally "rediscovered" by the news media. Ra is a decay product of uranium (U), which is associated with the organic carbon in black shales. Black shales are identified by a kick in the gamma ray well log, and drill cuttings occasionally contain enough U to require special handling at landfills. U is typically not very mobile in water, but Ra is quite soluble. Rn is a decay product of Ra, and most isotopes have a short half-life (source: https://www.epa.gov/radiation/tenorm-oil-and-gas-production-wastes).

Radium is an alpha emitter that is of particular risk if ingested – it is in the same family of chemical elements as Ca and Mg, and tends to lodge in the bones. However, no one is drinking ultra-saline produced water. Current practices for handling produced water, such as recycling it into subsequent fracks or disposing of it down UIC wells have effectively kept most of the Ra out of the environment, but of course people do get sloppy and spill things.

Not surprisingly, higher radium in produced water appears to correlate with higher TDS levels, and also with a brine source in U-bearing black shale. Measurements on produced water from the Marcellus Shale found a mean Ra value of 2460 picocuries per liter (pC/l) compared to 1011 pC/l in non-Marcellus, conventional oilfield brines (Rowan et al. 2011). For reference, the maximum Ra limit in industrial effluent is 60 pC/l, and the EPA drinking water limit is 5 pC/l. The highest concentration of Ra in oil and gas well operations appears to be in the mineral precipitate or "scale" that forms inside pipes, where it readily substitutes for Ca in calcite deposits.

Radon gas is a decay product of radium. It is a non-reactive, noble gas like helium or neon with a half-life of only a couple of days. No one worried much about Rn when natural gas spent weeks in a pipeline coming up north from the Gulf Coast, but the Marcellus Shale production is only a hundred miles (160 km) from New York City. Radon in Marcellus Shale gas samples collected at wellheads ranged from 1 pC/l to 79 pC/l (Rowan and Kraemer 2012). With transit times from wellhead to burner of only a few days, it may be entering people's homes in amounts above the EPA limit of 4 pC/l in air. Most large natural gas appliances like furnaces are vented outside, but some smaller uses such as gas stove burners or gas ovens vent directly into room air. Rn is the second leading cause of lung cancer in the United States, after tobacco. If the gas was stored for a few weeks before being used, the risk would be remediated.

Radon in natural gas, radium in produced water, and uranium in solid shale cuttings are designated by regulators as Naturally-Occurring Radioactive Material, or NORM. These are generally considered to be an acceptable risk in the production of oil and gas. However, some regulators are classifying radium as Technologically-Enhanced NORM, or TE-NORM, arguing that without the application of fracking technology, the radium-bearing water wouldn't be reaching the surface. Discussions about classifying, mitigating, and remediating NORM and TE-NORM are ongoing in the regulatory, oil & gas, mining, and radiological health communities (ICF Consulting 2000).

6.3 Water Supply and Disposal

The amount of water needed for hydraulic fracturing is often cited as being "millions of gallons" per frack. While individual frack stages rarely use this much, the multi-stage fracks on shale wells can easily consume tens of millions of gallons in total. Some concerns have been raised about the impacts of this usage on local water resources, because on some shale plays like the Marcellus, only a small percentage of the injected frack water returns to the surface as flowback (Soeder 2017). Water that remains in the formation downhole is removed from the water cycle, and essentially lost forever. Other shale plays in places like Texas return much more. The USGS is attempting to assess the amount of water consumed by unconventional O&G development on a national level using water budget models, but the issue is complicated, data are difficult to obtain, and there are many loose ends (Carter et al. 2016).

In the early days of shale development, operators purchased finished tap water from local utilities for hydraulic fracturing (Soeder 2017). Experience with swelling shales on the Gulf Coast had cautioned them to believe that only very clean water could be used for fracking shale. This certainly had a direct impact on drinking water supplies because the O&G industry was using actual drinking water, but the effect has not been quantified. It turned out that most of the shales containing tight oil and gas resources are so thermally mature that no swelling or mixed layer clays were left to cause problems with formation damage or borehole collapse. Service companies found that much lower quality (and far cheaper) water supplies could be used successfully for hydraulic fracturing. Most frack water these days is obtained directly from rivers and streams, often below the outfall of a wastewater treatment plant, or from brackish aquifers that contain groundwater too salty to drink. The purchase of finished tap water for fracks has been curtailed, much to the disappointment of a number of water utility companies that had been doing quite well with sales.

The issue of water availability is a concern, especially for fracking in areas that may have limited water supplies. This is a worry in the Permian Basin that straddles the Texas-New Mexico border area (Chapa 2019). Water supply and produced water management have both become big issues here, and water is now big business in this booming area. Because hydraulic fracturing can be done with lower quality water, both recycled produced water and undrinkable, brackish groundwater are being used to supplement freshwater supplies for fracking.

On other shale plays, water is generally being obtained from large sources like the Ohio River for fracking in the Marcellus and Utica shales, and from the Missouri River for the Bakken Shale. The multiagency investigation run by the U.S. government from 2012 to 2017 to assess the environmental impacts of unconventional oil and gas development had "water availability" as one of the areas of concern (USDOE 2015).

The multiagency study found that the water withdrawals for use on a shale play are less than the water used by a small to medium-size city. Of course, a city returns most of its water back to the watershed as runoff or wastewater effluent, while fracking loses half to two thirds of the water downhole, where it remains forever. This so-called "consumptive use" is a concern because it effectively removes water permanently from a watershed, and it can affect a water supply. How this might influence surface water and groundwater supplies is unclear, but some studies claim to have documented consumptive water use by fracking that was detrimental to ecosystems (Entrekin et al. 2018). However, given all of the competing demands for water use in populated areas, the amounts required for fracking are comparatively small.

Most O&G wells do produce substantial amounts of formation water along with hydrocarbons. The water cut ratio is generally about two to five barrels of saline water for every barrel of oil and will often vary over the life of the well. O&G production sites typically have a tall, narrow, vertical tank called a separator located near the wellhead that uses gravity to separate water, oil, and gas. The volume of produced water that is economically tolerable from a well depends on the price of oil and gas, because the water cut incurs handling and disposal costs. As the oil and gas in a conventional reservoir are depleted, brines migrate up from below and the remaining hydrocarbons often become isolated, non-mobile phases trapped in the pore spaces. At this point, the well is producing almost nothing but brine, and is said to have "watered-out." Depending on what is left in the subsurface and the current price of oil, it will either go into secondary or enhanced oil recovery, or it will be abandoned. Mainstream operators often divest themselves of these watered-out wells by selling them to small operators at very low prices. The wells would be run for a few years as so-called "stripper wells" that produced only a few barrels of oil per day. The strategy for the “fire sale” prices was that the liability for proper P&A of the well was no longer the responsibility of the original operator.

Sometimes a beneficial use such as crop irrigation can be found for O&G produced water if it is relatively fresh. Unfortunately, most of the formation water from deep production wells is very salty brine that is not useful, at least not on crops. The TDS in produced water from the Marcellus Shale is about six times higher than seawater (Hayes 2009). Water produced from the Bakken Shale is up to ten times saltier than the ocean (Cozzarelli et al. 2017). As mentioned earlier, the brines are high in chlorides, bromides, various toxic metals, and often contain radium. These high TDS fluids must be disposed of in a safe and cost-effective manner.

Municipal wastewater treatment plants were commonly used for the disposal of produced water during the early stages of shale gas development in the U.S. (Soeder 2017). These facilities, designated “Publicly-Owned Treatment Works” or POTWs by the EPA, are designed to remove suspended solids and plant nutrients from municipal sewage to prevent downstream algal blooms and fish-killing anoxia. They do essentially nothing for dissolved inorganic solids, however, and the high TDS brines went right through them and exited the effluent pipes into freshwater streams. As one can imagine, this saltwater had a rather negative effect on the downstream biota. A 2011 risk analysis of the disposal of produced water through POTWs in Pennsylvania concluded that at least 200 m^3 of high TDS fluids from each Marcellus Shale well were being released as effluent into streams (Rozell and Reaven 2012). At the time, this was identified as one of the greatest environmental risks of shale gas development. Despite changes in practices for most shale gas operators, POTWs are still used for some produced water disposal if an industrial sewer discharge permit can be obtained.

Another option for surface disposal of produced water is known as a centralized wastewater treatment plant or CWT. These are commonly privately-owned (versus municipal) facilities set up for the treatment and disposal of industrial wastewater from factories and other manufacturing operations. The EPA is currently investigating the amount of shale gas wastewater being accepted by CWT facilities, the available treatment technologies and costs, discharge characteristics, and environmental impacts (https://www.epa.gov/uog#swdischarges).

In addition to detrimental impacts on aquatic ecosystems, the bromides and chlorides in produced water can also cause human health effects. Although no one is directly drinking the produced water from an oil well, these chemicals may combine with natural organic material in surface streams to form halogenated compounds. If the stream provides a drinking water supply that is subsequently disinfected by chlorination, these precursor compounds will react with the chlorine to create new substances known as disinfection byproducts (DBPs) in the treated water (Hladik et al. 2014). DBPs include brominated tri-halo methane and halo-acetic acids, both of which have been linked in laboratory experiments to cancer and other health problems in humans (Coffin et al. 2000). DBPs do not form in drinking water that has been disinfected using ozone, but ozone treatments are more expensive and therefore less common than chlorine.

A surface disposal process for produced water that is commonly used in the arid west is to allow it to evaporate from an open tank. This requires a bit of patience, but once all the liquid is gone, the remaining minerals can be disposed of as solid waste. Evaporation is not an option in the humid east, and other disposal methods must be employed.

In early 2011, the Secretary of the Pennsylvania Department of Environmental Protection (PADEP) appealed to Marcellus Shale operators to stop using POTWs to dispose of produced water (Soeder 2017). Operators in Pennsylvania voluntarily complied, and bromide levels in the Monongahela River dropped soon afterward (Wilson and VanBriesen 2012). The PADEP recommended that TDS be removed from produced water prior to disposal by flash distillation or membrane filtration at the CWT facilities used by heavy industry or disposed down Class II-D UIC wells, designated for oilfield waste. Operators in West Virginia followed, although careless handling of the hypersaline produced water has also led to environmental issues. Along with the produced water pipeline break described previously that contaminated a North Dakota creek (Cozzarelli et al. 2017), USGS researchers have found that surface spills of high TDS fluids around disposal wells in West Virginia have led to the contamination of nearby streams (Akob et al. 2016).

The injection of residual wastewater into the deep subsurface occasionally results in induced earthquakes, discussed in more detail in the next chapter. There were few existing UIC wells in Pennsylvania for Marcellus produced water, requiring the wastewater to be hauled to Ohio or West Virginia for injection. The new requirements for disposing of Marcellus produced water through CWT facilities or down UIC wells resulted in a fivefold increase in the cost of residual wastewater disposal (Rodriguez and Soeder 2015).

In the Appalachian Basin, the shale gas industry understood that only a relatively small percentage of injected frack water is returned as flowback. A lot of the water they were putting into the ground for hydraulic fracturing remained downhole and therefore was not part of the disposal cost. Industry soon realized that if the flowback and produced water that did return to the surface could be recycled into the next frack, most of that would remain in the ground as well. Recycling the produced water into subsequent fracks proved to be a cost-effective, *de facto* method of disposal. As an added bonus, the recycling practice greatly reduced the volume of residual wastewater that ultimately had to be handled by UIC wells or CWT facilities.

Once the recycling process became established, nearly 90% of the relatively fresh flowback water was recycled into additional fracks. The higher saline produced water from later in production was also recycled, but the high levels of TDS interfered with the properties of the ionic surfactants and friction reducers. More freshwater was required to dilute the salinity down to acceptable levels (Maloney and Yoxtheimer 2012).

Everything has consequences, and the recycling process for frack water resulted in the development of biocide-resistant microbes (Vikram et al. 2014). Biocides are used to control the growth of bacteria that are introduced downhole with the frack fluids. A particular variety of microbes known as “sulfate reducers” may metabolize subsurface sulfate compounds and create hydrogen sulfide gas (H_2S) as a byproduct. H_2S is toxic to humans and also causes the production gas to become "sour" and corrosive. It must be removed before the gas will meet pipeline specifications and can be sold. Biocide alternatives, such as disinfection with ultraviolet light, have been found to be less economical (Kahrilas et al. 2015).

Biocide types are either oxidizing (i.e. bleach, peroxide) or non-oxidizing. Non-oxidizing biocides tend to be gentler on equipment and rock formations, and are more commonly used in hydraulic fracturing operations. There are two main classes: lytic biocides attack and dissolve the cell walls of bacteria, while electrophilic biocides bind themselves to bacterial cell walls (Kahrilas et al. 2015).

Biocides are effective at controlling "most" of the downhole microbes. A fraction of a percent with a resistance to the biocide will survive, however, and following Darwin's Law of Natural Selection the survivors pass that resistance on to their descendants. A metagenomic analysis compared microbial populations in produced water from the Marcellus Shale, which may be recycled through a dozen different fracks, with microbes in Bakken Shale produced water, which is only used once and then disposed of. The study found that microbial populations in the Marcellus water were three to four orders of magnitude greater those found in the Bakken water (Lipus et al. 2017). The biocide-resistant microbes were found to biodegrade some of the organic frack fluid additives, creating new toxic daughter products that may impact human and ecological health.

The handling of produced waters from shale gas and tight oil development is a major production cost and poses huge economic challenges to the industry. These fluids have also been identified as the primary concern for potential human exposures, because they contain both chemical additives from the hydraulic fracturing process and the naturally-occurring components of the brines that are produced with the oil and gas (HEI, 2019). While large spills of produced water are rare (Cozzarelli et al. 2017) small spills do occur on a somewhat regular basis during storage, transport, and disposal operations (Orem et al. 2017). Improved handling protocols, monitoring, and training of workers can help reduce the frequency and seriousness of these incidents.

References

Akob, D. M., Mumford, A. C., Orem, W., Engle, M. A., Klinges, J. G., Kent, D. B., & Cozzarelli, I. M. (2016). Wastewater disposal from unconventional oil and gas development degrades stream quality at a West Virginia injection facility. *Environmental Science & Technology, 50*, 5517–5525.

Bair, E. S., & Tomastik, T. (2012). *Geologic and hydrogeologic factors controlling how stray gas from the English #1* Well Invaded Residential Homes, Geauga County, Ohio, Causing One In-Home Explosion. Presentation at Stray Gas Incidence and Response Forum, July 24–26, Cleveland, Ohio, in Veil, J. (2012). A white paper summarizing the stray gas incidence & response forum, Ground Water Protection Council, 48 p. http://www.gwpc.org/sites/default/files/files/stray%20gas%20white%20paper-final(2).pdf. Accessed 25 Oct, 2019.

Baldassare, F. J., McCaffrey, M. A., & Harper, J. A. (2014). A geochemical context for stray gas investigations in the northern Appalachian Basin: Implications of analyses of natural gases from Neogene-through Devonian-age strata. *American Association of Petroleum Geologists Bulletin, 98*, 341–372.

Barth-Naftilan, E., Sohng, J., & Saiers, J. E. (2018). Methane in groundwater before, during, and after hydraulic fracturing of the Marcellus Shale. *Proceedings of the National Academy of Sciences, 115*(27), 6970–6975. https://doi.org/10.1073/pnas.1720898115.

Birdsell, D. T., Rajaram, H., Dempsey, D., & Viswanathan, H. S. (2015). Hydraulic fracturing fluid migration in the subsurface: A review and expanded modeling results. *Water Resources Research, 51*(9), 7159–7188.

Brantley, S. L., Yoxtheimer, D., Arjmand, S., Grieve, P., Vidic, R., Pollak, J., Llewellyn, G. T., Abad, J., & Simon, C. (2014). Water resource impacts during unconventional shale gas development: The Pennsylvania experience. *International Journal of Coal Geology, 126*, 140–156.

Brantley, S. L., Vidic, R. D., Brasier, K., Yoxtheimer, D., Pollak, J., Wilderman, C., & Wen, T. (2018). Engaging over data on fracking and water quality. *Science, 359*(6374), 395–397. https://doi.org/10.1126/science.aan6520.

Cahill, A. G., Steelman, C. M., Forde, O., Kuloyo, O., Ruff, E., Mayer, B., Mayer, K. U., Strous, M., Ryan, M. C., Cherry, J. A., & Parker, B. L. (2017). Mobility and persistence of methane in groundwater in a controlled-release field experiment. *Nature Geoscience, 10*(3), 289–294.

Carter, J. M., Macek-Rowland, K. M., Thamke, J. N., & Delzer, G. C. (2016). *Estimating national water use associated with unconventional oil and gas development*. USGS Fact Sheet 2016-3032, 6 p.

Chapa, S. (2019). New laws could pump billions of dollars into Permian Basin's rapidly growing water recycling industry. *Houston Chronicle*, August 2, 2019.

Chapman, E. C., Capo, R. C., Stewart, B. W., Kirby, C. S., Hammack, R. W., Schroeder, K. T., & Edenborn, H. M. (2012). Geochemical and strontium isotope characterization of produced waters from Marcellus Shale natural gas extraction. *Environmental Science & Technology, 46*(6), 3545–3553.

Cherry, J. A., Barker, J. F., Feenstra, S., Gillham, R. W., Mackay, D. M., & Smyth, D. J. A. (1996). The Borden site for groundwater contamination experiments: 1978–1995. In H. Kobus, B. Barczewski, & H. P. Koschitzky (Eds.), *Groundwater and subsurface remediation, environmental engineering* (pp. 101–127). Berlin/Heidelberg: Springer.

Cluff, M., Hartsock, A., Macrae, J., Carter, K., & Mouser, P. J. (2014). Temporal changes in microbial ecology and geochemistry in produced water from hydraulically fractured Marcellus shale gas wells. *Environmental Science & Technology, 48*, 6508–6517.

Coffin, J. C., Ge, R., Yang, S., Kramer, P. M., Tao, L., & Pereira, M. A. (2000). Effect of trihalomethanes on cell proliferation and DNA methylation in female B6C3F1 mouse liver. *Toxicological Sciences, 58*(2), 243–252.

Council of Canadian Academies. (2014). *Environmental impacts of shale gas extraction in Canada: Expert panel on harnessing science and technology to understand the environmental impacts of shale gas extraction*. Ottawa, ON: Council of Canadian Academies/Conseil des Academies Canadiennes. 262 p.

Cozzarelli, I. M., Skalak, K. J., Kent, D. B., Engle, M. A., Benthem, A., Mumford, A. C., Haase, K., Farag, A., Harper, D., Nagel, S. C., Iwanowicz, L. R., Orem, W. H., Akob, D. M., Jaeschke, J. B., Galloway, J., Kohler, M., Stoliker, D. L., & Jolly, G. (2017). Environmental signatures and effects of a spill of untreated oil and gas wastewater in the Williston Basin, North Dakota. *Science of the Total Environment, 579C*, 1782–1795. https://doi.org/10.1016/j.scitotenv.2016.11.157.

Davies, R. J., Almond, S., Ward, R. S., Jackson, R. B., Adams, C., Worrall, F., Herringshaw, L. G., Gluyas, J. G., & Whitehead, M. A. (2014). Oil and gas wells and their integrity: Implications for shale and unconventional resource exploitation. *Marine and Petroleum Geology, 56*, 239–254. https://doi.org/10.1016/j.marpetgeo.2014.03.001.

Detrow, S. (2012). *Perilous pathways: How drilling near an abandoned well produced a methane geyser: State impact Pennsylvania (NPR)*. Posted October 9, 2012, 8:30 AM. https://stateimpact.npr.org/pennsylvania/tag/perilous-pathways/. Accessed May 12, 2019.

Drollette, B. D., Hoelzer, K., Warner, N. R., Darrah, T. H., Karatum, O., O'Connor, M. P., Nelson, R. K., Fernandez, L. A., Reddy, C. M., Vengosh, A., Jackson, R. B., Elsner, M., & Plata, D. L. (2015). Elevated levels of diesel range organic compounds in groundwater near Marcellus gas operations are derived from surface activities. *Proceedings of the National Academy of Sciences, 112*(43), 13184–13189.

Engelder, T., & Zevenbergen, J. (2018). Analysis of a gas explosion in Dimock PA (USA) during fracking operations in the Marcellus gas shale. *Process Safety and Environmental Protection, 117*, 61–66.

Entrekin, S., Trainor, A., Saiers, J., Patterson, L., Maloney, K., Fargione, J., Kiesecker, J., Baruch-Mordo, S., Konschnik, K., Wiseman, H., Nicot, J.-P., & Ryan, J. N. (2018). Water stress from high-volume hydraulic fracturing potentially threatens aquatic biodiversity and ecosystem services in Arkansas, United States. *Environmental Science & Technology, 52*(4), 2349–2358.

Fisher, K., & Warpinski, N. (2012). Hydraulic fracture height growth: Real data. *SPE Production & Operations, 27*(1), 8–19.

Forde, O. M., Mayer, K. U., & Hunkeler, D. (2019). Identification, spatial extent, and distribution of fugitive gas migration on the well pad scale. *Science of the Total Environment, 652*, 356–366.

Gassiat, C., Gleeson, T., Lefebvre, R. R., & McKenzie, J. (2013). Hydraulic fracturing in faulted sedimentary basins: Numerical simulation of potential contamination of shallow aquifers over long time scales. *Water Resources Research, 49*(12), 8310–8327.

Geng, X., Davatzes, N. C., Soeder, D. J., Torlapati, J., Rodriguez, R. S., & Boufadel, M. C. (2014). Migration of high-pressure air during gas well drilling in the Appalachian Basin. *Journal of Environmental Engineering, 140*(5), B4014002., 46 p. https://doi.org/10.1061/(ASCE)EE.1943-7870.0000769.

Hammack, R. W., & Veloski, G. A. (2016). *Methods for finding legacy Wells in residential and commercial areas*. NETL-TRS-5-2016, NETL technical report series, U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 24 p.

Hammack, R., Harbert, W., Sharma, S., Stewart, B., Capo, R., Wall, A., Wells, A., Diehl, R., Blaushild, D., Sams, J., & Veloski, G. (2014). *An evaluation of fracture growth and gas/fluid migration as horizontal Marcellus shale gas Wells are hydraulically fractured in Greene County, Pennsylvania*. NETL-TRS-3-2014; EPAct technical report series; U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 76 p.

Hammack, R. W., Veloski, G. A., Hodges, D. G., & White, C. M. (2016). *Methods for finding legacy wells in large areas*. NETL-TRS-6-2016, EPAct technical report series, U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 28 p.

Harkness, J. S., Darrah, T. H., Warner, N. R., Whyte, C. J., Moore, M. T., Millot, R., Kloppmann, W., Jackson, R. B., & Vengosh, A. (2017). The geochemistry of naturally occurring methane and saline groundwater in an area of unconventional shale gas development. *Geochimica et Cosmochimica Acta, 208*, 302–334.

Hayes, T. (2009). *Sampling and analysis of water streams associated with the development of Marcellus shale gas*. Gas Technology Institute, Chicago; final report for Marcellus Shale Coalition, 49 p.

HEI (Health Effects Institute). (2019). *Human exposure to unconventional oil and gas development: A literature survey for research planning: Special report 2 (Draft for Public Comment)*: Boston, HEI-Energy Research Committee, 108 p. www.hei-energy.org

Hladik, M. L., Focazio, M. J., & Engle, M. (2014). Discharges of produced waters from oil and gas extraction via wastewater treatment plants are sources of disinfection by-products to receiving streams. *Science of the Total Environment, 466*, 1085–1093.

ICF Consulting. (2000). *Overview of exploration and production waste volumes and waste management practices in the United States*. Report prepared for The American Petroleum Institute, Washington, DC, 112 p. (including appendixes).

Ingraffea, A. R., Wells, M. T., Santora, R. L., & Shonkoff, S. B. (2014). Assessment and risk analysis of casing and cement impairment in oil and gas wells in Pennsylvania, 2000–2012. *Proceedings of the National Academy of Sciences, 11*, 10955–11096.

Jackson, R. E., Gorody, A. W., Mayer, B., Roy, J. W., Ryan, M. C., & Van Stempvoort, D. R. (2013). Groundwater protection and unconventional gas extraction: The critical need for field-based hydrogeological research. *Groundwater, 51*(4), 488–510.

Kahrilas, G. A., Blotevogel, J., Stewart, P. S., & Borch, T. (2015). Biocides in hydraulic fracturing fluids: A critical review of their usage, mobility, degradation, and toxicity. *Environmental Science & Technology, 49*(1), 16–32.

Kang, M., Kanno, C. M., Reid, M. C., Zhang, X., Mauzerall, D. L., Celia, M. A., Chen, Y., & Onstott, T. C. (2014). Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania. *Proceedings of the National Academy of Sciences, (PNAS), 111*(51), 18173–18177. https://doi.org/10.1073/pnas.1408315111.

Kang, M., Christian, S., Celia, M. A., Mauzerall, D. L., Bill, M., Miller, A. R., Chen, Y., Conrad, M. E., Darrah, T. H., & Jackson, R. B. (2016). Identification and characterization of high methane-emitting abandoned oil and gas wells. *Proceedings of the National Academy of Sciences, 113*(48), 13636–13641. https://doi.org/10.1073/pnas.1605913113.

Larson, T. E., Nicot, J.-P., Mickler, P., Castro, M. C., Darvari, R., Wen, T., & Hall, C. M. (2018). Monitoring stray natural gas in groundwater with dissolved nitrogen: An example from Parker County, Texas. *Water Resources Research, 54*(9), 6024–6041.

Lefebvre, R. (2016). Mechanisms leading to potential impacts of shale gas development on groundwater quality. *Wiley Interdisciplinary Reviews: Water, 4*(1), e1188., 15 p. https://doi.org/10.1002/wat2.1188.

Li, Z., You, C., Gonzales, M., Wendt, A. K., Wu, F., & Brantley, S. L. (2016, December). Searching for anomalous methane in shallow groundwater near shale gas wells. *Journal of Contaminant Hydrology, 195*, 23–30.

Lipus, D., Vikram, A., Ross, D., Bain, D., Gulliver, D., Hammack, R., & Bibby, K. (2017). Predominance and metabolic potential of *Halanaerobium* spp. in produced water from hydraulically fractured Marcellus shale wells. *Applied and Environmental Microbiology, 83*, e02659-16. https://doi.org/10.1128/AEM.02659-16.

Llewellyn, G. T., Dorman, F., Westland, J. L., Yoxtheimer, D., Grieve, P., Sowers, T., Humston-Fulmer, E., & Brantley, S. L. (2015). Evaluating a groundwater supply contamination incident attributed to Marcellus Shale gas development. *Proceedings of the National Academy of Sciences, 112*(20), 6325–6330.

Maloney, K. O., & Yoxtheimer, D. A. (2012). Production and disposal of waste materials from gas and oil extraction from the Marcellus shale play in Pennsylvania. *Environmental Practice, 14*, 278–287.

McMahon, P. B., Caldwell, R. R., Galloway, J. M., Valder, J. F., & Hunt, A. G. (2015). Quality and age of shallow groundwater in the Bakken formation production area, Williston basin, Montana and North Dakota. *Groundwater, 53*, 81–94.

McMahon, P. B., Kulongoski, J. T., Wright, M. T., Land, M. T., Landon, M. K., Cozzarelli, I. M., Vengosh, A., & Aiken, G. R. (2016). *Preliminary results from exploratory sampling of wells for the California oil, gas, and groundwater program, 2014-15*. U.S. Geological Survey Open-File Report 2016-1100, 8 p. https://doi.org/10.3133/ofr20161100.

McMahon, P. B., Barlow, J. R. B., Engle, M. A., Belitz, K., Ging, P. B., Hunt, A. G., Jurgens, B. C., Kharaka, Y. K., Tollett, R. W., & Kresse, T. M. (2017). Methane and benzene in drinking-water wells overlying the Eagle Ford, Fayetteville, and Haynesville shale hydrocarbon production areas. *Environmental Science & Technology, 51*(12), 6727–6734.

McMahon, P. B., Lindsey, B. D., Conlon, M. D., Hunt, A. G., Belitz, K., Jurgens, B. C., & Varela, B. A. (2019). Hydrocarbons in upland groundwater, Marcellus shale region, northeastern Pennsylvania and southern New York, USA. *Environmental Science & Technology*, Online Publication Date: 27 June 2019. https://doi.org/10.1021/acs.est.9b01440

Molofsky, L. J., Connor, J. A., Wylie, A. S., Wagner, T., & Farhat, S. K. (2013, May–June). Evaluation of methane sources in groundwater in Northeastern Pennsylvania. *Groundwater, 51*(3), 333–349.

Orem, W. H., Tatu, C. A., Varonka, M. S., Lerch, H. E., Bates, A. L., Engle, M. A., Crosby, L. M., & McIntosh, J. (2014). Organic substances in produced and formation water from unconventional natural gas extraction in coal and shale. *International Journal of Coal Geology, 126*, 20–31.

Orem, W., Varonka, M., Crosby, L., Haase, K., Loftin, K., Hladik, M., Akob, D. M., Tatu, C., Mumford, A., Jaeschke, J., Bates, A., Schell, T., & Cozzarelli, I. (2017, May). Organic geochemistry and toxicology of a stream impacted by unconventional oil and gas wastewater disposal operations. *Applied Geochemistry, 80*, 155–167.

Osborn, S. G., Vengosh, A., Warner, N. R., & Jackson, R. B. (2011). Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing. *Proceedings of the National Academy of Sciences, 108*(20), 8172–8176.

Phan, T. T., Capo, R. C., Stewart, B. W., Graney, J. R., Johnson, J. D., Sharma, S., & Toro, J. (2015). Trace metal distribution and mobility in drill cuttings and produced waters from Marcellus shale gas extraction: Uranium, arsenic, barium. *Applied Geochemistry, 60*, 89–103.

Pope, P.G., 2012, *Parker County study: Presentation at stray gas incidence and response forum*, July 24–26, Cleveland, Ohio, in Veil, J. (2012). A white paper summarizing the stray gas incidence & response forum, Ground Water Protection Council, 48 p. http://www.gwpc.org/sites/default/files/files/stray%20gas%20white%20paper-final(2).pdf. Accessed 25 Oct 2019.

Renock, D., Landis, J. D., & Sharma, M. (2016). Reductive weathering of black shale and release of barium during hydraulic fracturing. *Applied Geochemistry, 65*, 73–86.

Rodriguez, R. S., & Soeder, D. J. (2015). Evolving water management practices in shale oil & gas development. *Journal of Unconventional Oil and Gas Resources, 10*, 18–24.

Rowan, E. L., & Kraemer, T. F. (2012). *Radon-222 Content of natural gas samples from Upper and Middle Devonian sandstone and shale reservoirs in Pennsylvania – Preliminary data*. U.S. Geological Survey OFR 2012–1159, 6 p, http://pubs.usgs.gov/of/2012/1159.

Rowan, E. L., Engle, M. A., Kirby, C. S., & Kraemer, T. F. (2011). *Radium content of oil- and gas-field produced waters in the northern Appalachian Basin (USA) – Summary and discussion of data*. U.S. Geological Survey SIR 2011–5135, 31 p.

Rozell, D. J., & Reaven, S. J. (2012, August). Water pollution risk associated with natural gas extraction from the Marcellus shale. *Risk Analysis, 32*(8), 1382–1393.

Sandl, E., Cahill, A. G., Beckie, R. D., & Welch, L. A. (2019). *Assessing the association between oil and gas well attributes and the occurrence for fugitive gas migration in British Columbia*. (Abstract) presentation H54B-02, AGU Fall Meeting, 9–13 December, San Francisco, CA, USA, American Geophysical Union.

Schwartz, M. O. (2015). Modelling the hypothetical methane-leakage in a shale-gas project and the impact on groundwater quality. *Environmental Earth Sciences, 73*, 4619–4632. https://doi.org/10.1007/s12665-014-3787-3.

Siegel, D. I., Azzolina, N. A., Smith, B. J., Perry, A. E., & Bothun, R. L. (2015). Methane concentrations in water wells unrelated to proximity to existing oil and gas wells in northeastern Pennsylvania. *Environmental Science & Technology, 49*, 4106–4112.

Soeder, D. J. (2015). Adventures in groundwater monitoring: Why has it been so difficult to obtain groundwater data near shale gas wells? *Environmental Geosciences, 22*(4), 139–148.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J. (2018). Groundwater quality and hydraulic fracturing: Current understanding and science needs. *Groundwater, 56*(6), 852–858.

Soeder, D. J., & Kent, D. B. (2018). When oil and water mix: Understanding the environmental impacts of shale development. *GSA Today, 28*(9), 4–10.

Soeder, D. J., Sharma, S., Pekney, N., Hopkinson, L., Dilmore, R., Kutchko, B., Stewart, B., Carter, K., Hakala, A., & Capo, R. (2014). An approach for assessing engineering risk from shale gas wells in the United States. *International Journal of Coal Geology, 126*, 4–19.

USDOE. (2015). *Report on the multiagency collaboration on unconventional oil and gas research*, USDOE Office of Fossil Energy, Report to Congress on behalf of the Multiagency Collaboration (MAC), December 2015, 24 p.

USEPA. (2016). *Hydraulic fracturing for oil and gas: Impacts from the hydraulic fracturing water cycle on drinking water resources in the United States (Final Report): EPA/600/R-16/236F*, Washington, DC, 664 p.

Vengosh, A., Jackson, R. B., Warner, N., Darrah, T. H., & Kondash, A. (2014). A critical review of the risks to water resources from unconventional shale gas development and hydraulic fracturing in the United States. *Environmental Science & Technology, 48*, 8334–8348.

Vidic, R. D., Brantley, S. L., Vandenbossche, J. M., Yoxtheimer, D., & Abad, J. D. (2013). Impact of shale gas development on regional water quality. *Science, 340*, 826 (1235009).

Vikram, A., Lipus, D., & Bibby, K. (2014). Produced water exposure alters bacterial response to biocides. *Environmental Science & Technology, 48*(21), 13001–13009.

Warner, N. R., Jackson, R. B., Darrah, T. H., Osborn, S. G., Down, A., Zhao, K., White, A., & Vengosh, A. (2012). Geochemical evidence for possible natural migration of Marcellus formation brine to shallow aquifers in Pennsylvania. *Proceedings of the National Academy of Sciences, (PNAS), 109*(30), 11961–11966.

Wilson, J. M., & VanBriesen, J. M. (2012). Oil and gas produced water management and surface drinking water sources in Pennsylvania. *Environmental Practice, 14*, (4), 288–300. https://doi.org/10.1017/S1466046612000427.

Woda, J., Wen, B., Oakley, D., Yoxtheimer, D., Engelder, T., Castro, M. C., & Brantley, S. L. (2018). Detecting and explaining why aquifers occasionally become degraded near hydraulically fractured shale gas wells. *Proceedings of the National Academy of Sciences, 115*(49), 12349–12358. https://doi.org/10.1073/pnas.1809013115.

Yan, B., Stute, M., Panettieri, R. A., Jr., Ross, J., Mailloux, B., Neidell, M. J., Soares, L., Howarth, M., Liu, X., Saberi, P., & Chillrud, S. N. (2017). Association of groundwater constituents with topography and distance to unconventional gas wells in NE Pennsylvania. *Science of the Total Environment, 577*, 195–201.

Zhang, L., & Soeder, D. J. (2016). Modeling of methane migration in shallow aquifers from shale gas well drilling. *Groundwater, 54*(3), 345–353. https://doi.org/10.1111/gwat.12361.

Chapter 7
Effects on Landscapes

According to O&G opponents, pastoral, rural landscapes become “industrialized” when shale gas and tight oil development takes place. Although this is true, it is also temporary. Large drill rigs, earthmovers, tons of gravel, and dozens of hauling, monitoring, and pump trucks are needed to drill and frack a well. It can be extremely disruptive and overwhelming while it is happening, but like all construction sites, eventually they finish up and move on.

Because a lot of shale gas development has occurred in locations that do not have a history of large-scale oil and gas drilling, local populations were often stunned by the size of the operations and the amount of equipment needed to install these wells. Places like southwestern Pennsylvania and northern Arkansas were familiar with small, truck-mounted drill rigs that could penetrate a few thousand feet of rock to drill for oil, gas, or water. They were now faced with gigantic triple drill rigs towering above the trees that could bore many kilometers into the Earth (Fig. 7.1). These are huge. They were shocking. Many people who had signed drilling leases and then found one of these in their backyard didn’t realize exactly what they were getting into.

Oil and gas drilling of both conventional and unconventional wells is a 24 hours per day, seven days a week business. They come in, rig up, and start the job. They don’t leave until the job is finished. Crews live in trailers on site, and work around the clock in 12-hour shifts. The noise is deafening, especially the screech when pulling pipe or setting casing. The rig is lit up at night like a Las Vegas casino, and the derrick is visible from miles away. (In fact, one of the best ways to spot drill rigs in an area is to look for them after dark because the derrick lights are easy to see.) People come and go at all hours, usually in large, loud pickup trucks. Natural gas may be flared off while completing the well, and light up the underside of a cloudy sky for miles in all directions. Anyone unfortunate enough to live across the street from one of these operations is not going to get much sleep.

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_7

Fig. 7.1 A triple drill rig towers over both trees and visitors at a Marcellus Shale site in Pennsylvania. (Photographed in 2011 by Dan Soeder)

7.1 Bulldozers Running Amok

Shale gas and tight oil wells have impacts on landscapes and habitats that are different from conventional wells. Because the unconventional wells require so much more room for equipment and materials to carry out drilling and fracking operations, the standard pad size is about five acres (2 ha). For people familiar with conventional, vertical O&G wells where small single or double drill rigs only require small pads perhaps a few hundred feet (dozen meters) square, the gigantic pads constructed for unconventional wells can come as quite a shock. Especially in the east, where landowners typically have much smaller parcels of land than in the west, a five-acre drill pad can represent a significant percentage of one's property.

A bit of an explanation about drill rigs might be useful. These are classified into offshore rigs and land rigs. Offshore rigs operate on platforms above the water that either stand on the bottom of the ocean or float. Platforms that stand on the bottom are known as jack-ups, and are used in shallow water. Deep water drilling requires a stable, floating platform. These come in two varieties: semi-submersibles and drill ships. Semi-submersibles are basically a floating raft anchored tightly to the bottom. The anchor cables pull the vessel partly underwater, and the buoyancy of the platform trying to rise back to the surface holds the cables in tension. These so-called "tension leg" platforms are very stable and can operate in water that is kilometers deep. They are expensive to move, however, requiring deep-diving submersibles with specialized crews to access the anchors. The deployment of tension leg platforms led the major oil companies to support advances in directional drilling technology so multiple wells could be drilled without moving the platform (refer back to Chap. 2). Drill ships are used in very deep water or other locations where anchoring to the bottom is not feasible. They employ a process called "station keeping" where constant adjustments from small directional propellers are used hold the ship in one spot. Although many offshore wells are fracked to improve conventional production, offshore rigs are not being used for unconventional oil and gas development in a significant way (at least not yet) so the remainder of this discussion will focus on land rigs.

Land rigs come in several different sizes from small, truck-mounted affairs to large modular units that are brought out to a drilling location in pieces and assembled on-site. Land rigs are described by the number of lengths of drill pipe they can pull from the ground in a single lift. Drill pipe and well casing both come in standard lengths of 30 feet (10 m), and each length is called a joint. Single rigs can pull one joint at a time, and are used for shallow water wells and seismic survey boreholes. Double rigs can pull two joints, and are larger, capable of drilling into oil and gas reservoirs at moderate depths. These are often employed as "workover" rigs to replace casing or repair cement in existing wells. The largest land-based rigs are triples that can pull three joints at a time. The rig shown in Fig. 7.1 is a triple; a close look at the stands of drill pipe stacked in the derrick reveals that they consist of three joints each.

Triple rigs are used for unconventional oil and gas drilling because they are able to construct deep boreholes with long laterals. Many gas shales are quite deep, and although some formations may be reachable with smaller rigs, continuing a vertical borehole into a lateral that may need to extend several kilometers horizontally is beyond their capability. Triple rigs are robust enough to drill record-setting wells like the Outlaw C11 H, constructed in the Utica Shale of Ohio by Eclipse Resources in 2017 (Soeder and Borglum 2019). According to a company news release, the lateral has a length of approximately 19,500 feet (5.9 km or 3.7 miles) with a total borehole length from the surface to the end of the lateral of about 27,750 feet (8.5 km or 5.25 miles). These extremely long wells are said to be very efficient, paying for the extra drilling costs with substantial returns. They also benefit the landscape, because longer laterals allow for greater well spacing on the surface.

The nominal spacing for vertical gas wells is one well per 40 acres (0.162 km^2). At the beginning of the shale gas revolution, George Mitchell started placing horizontal wells in the Barnett Shale at a spacing of 80 acres, but then quickly discovered that a wider spacing of 160 acres (0.647 km^2) was more efficient. This spacing became more-or-less standard during the development of many of the subsequent shale plays. The close spacing of the early Barnett pads is visible from aircraft windows on approach to Dallas-Fort Worth (DFW) airport (Fig. 7.2).

Spacing is play-dependent, and related to formation permeability, fracture trends, regional structure, and other factors. However, the trend has been toward longer laterals with multiple directional wells per pad, and on some plays like the Marcellus the drill pads have gone to spacings of 640 acres (Soeder 2017), equivalent to one well pad per square mile (2.59 km^2).

The construction of roads, drill pads, large water impoundments and other infrastructure for shale gas and tight oil development left significant impacts on the landscape. A few of the new shale plays like the Haynesville in Louisiana had some conventional O&G infrastructure already in place, but many others did not. Locations in northern Arkansas and northeastern Pennsylvania, respectively the sites of the Fayetteville and Marcellus shale plays, were rural and undeveloped, with few roads. The roads that did exist in these areas had not been designed for the transit of large, heavy equipment. Some locations were mountainous, with steep,

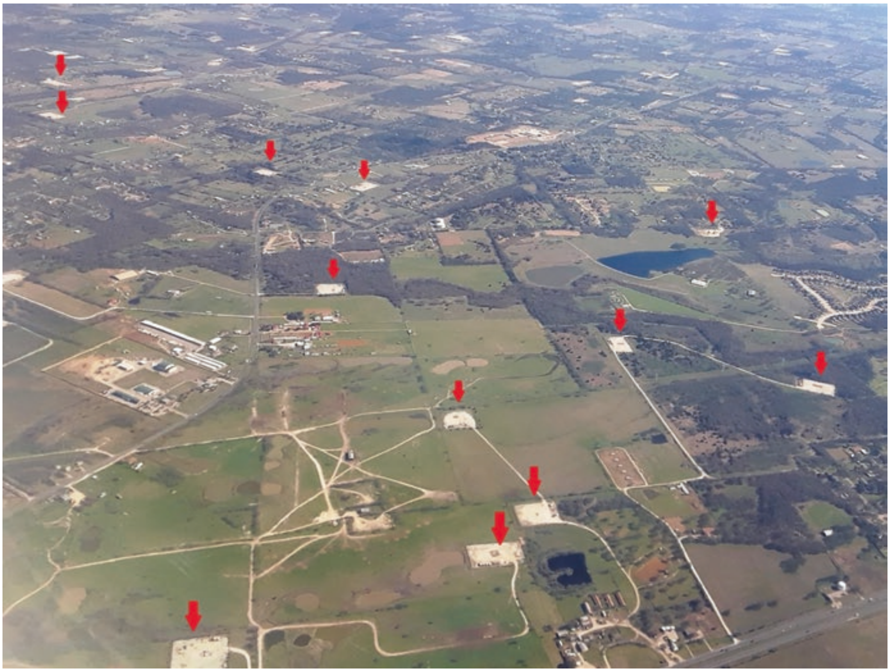


Fig. 7.2 Closely-spaced Barnett Shale drill pads (arrows) visible southwest of DFW Airport. (Photographed in 2019 by Dan Soeder)

narrow, winding roads that could not accommodate either the width or the turning radius of the giant triple drill rig components and other large equipment that needed to get to a drill pad. Thus, the first action often taken by industry when moving onto a new shale play was to bring in road graders and bulldozers to construct, widen and straighten roads so equipment and materials could get in and out. This usually did not endear them to the locals.

One might think that improved roads would be welcomed in rural areas (as indeed some were by county highway departments), but many people had moved to these areas in the first place seeking quiet and isolation. A picturesque country lane transformed into a broad avenue of packed dirt that was either choked with dust or mired in mud by a constant parade of semi-trucks and heavy machinery quickly soured many a rural landowner on the "benefits" of shale gas. Some roads that were often the only route into people's property were blocked for hours as equipment was gingerly maneuvered through tight turns or up steep hills. Although industry had widened and improved the roads, the constant heavy vehicle traffic typically left them as cratered as the moon within weeks. Local highway departments were often tasked with repairs.

One location that stands out in particular for landscape impacts is Wetzel County, WV. This small, rural county located in the northwestern part of the state alongside the Ohio River became a center of activity in 2008 during the early days of the Marcellus Shale boom. It sits at the base of the northern West Virginia panhandle with terrain that includes dendritic drainage, steep slopes, incised narrow stream valleys, and high bluffs. It is also a transit point for a number of interstate gas transmission pipelines, which attracted drillers because there was a market to sell Marcellus Shale gas. Of even greater interest, the Marcellus here also produces ethane as an NGL, which is used in the manufacture of polyethylene plastic.

Upland areas in Wetzel County are generally flatter than other terrain, and industry preferred these for building the large drill pads needed for fracking operations. However, to reach these locations, access roads had to be carved into the hills from the main highways that run along the Ohio River or through the larger stream valleys. This area bore the brunt of the shale gas boom at the end of the first decade of the twenty-first century. Dozens of well pads are located on the hilltops east of the Ohio River town of New Martinsville, the county seat.

Routes to the drill pads were often carved into valley walls along the edges of streams. Following the valley of a watercourse to a hilltop saved significantly on excavating costs, but improper road construction on such landscapes can be extremely destructive to small watersheds. Careless road building may result in excessive runoff, sediment-choked streams, unstable slopes, ponding of water behind embankments, groundwater contamination, flash floods, and poorly-drained flood plains, all of which may alter stream hydrology and damage aquatic habitat. Even roads that do not affect the stream channel itself can still cause damage in the riparian zone. This is a strip of vegetation along the stream bank that moderates runoff, traps sediment, allows for the exchange of surface water and groundwater, and reduces nutrient loads in the stream. The water quality of headwater streams and tributaries is critically important to the health of the main stream, and many small streams were seriously damaged in Wetzel County.

In 2008, natural gas prices were at record highs, and ethane was in demand. Companies were focused on getting pads built, and the wells drilled, fracked, completed, and on-line as quickly as possible. Some managers were pressured to take shortcuts, and an acute shortage of skilled labor meant that some of the heavy equipment operators being hired to do the work were not exactly experts at building roads. The U.S. Attorney in the Northern District of West Virginia documented a case in Wetzel County where a bulldozer simply plowed a road to an upland area straight up the bed of a small stream (Ihlenfeld 2012). The original stream was buried under several feet of fill, and what was left was reduced to a trickle in a ditch alongside the road, destroying any existing aquatic habitat. This and several similar cases were prosecuted in federal court as violations under Section 404 of the Clean Water Act (Ihlenfeld 2012).

When flat upland areas were not available for drill pads, cut-and-fill pads were excavated into hillsides to create level surfaces. Many of these are located on steep slopes and have high walls that suffered slumping, slippage, or erosion over time. Sediment from the eroded hillsides has ended up in streams, further compounding water quality problems. Even after more than ten years, many residents of Wetzel County are still seething about the environmental damage done to their landscape in the name of profit driven by the shale gas boom. The worst part of all is that this was completely unnecessary.

Road and pad construction can and has been done correctly in many places. County governments in Pennsylvania have worked with drillers to route traffic to wells around environmentally fragile areas and onto roads that are already slated for repair. In many cases, the drilling company has re-paved damaged roads at no cost to local governments after the wells were completed and all the equipment moved offsite. New roads that were needed for access to pad sites were designed with assistance from highway engineers to meet specifications that reduce runoff and protect watersheds. Drillers also avoided trying to move equipment and materials around during local rush hours or when school buses were actively picking up or dropping off students. It turned out that a little bit of engagement, communication, and preplanning can go a long way toward enlisting the tolerance of local citizens when companies are drilling and fracking shale wells. This is known as obtaining a “social license” to operate, and industry has discovered just how valuable it can be.

7.2 North Dakota from Space

Natural gas production requires a pipeline. There is just no other economical method of transmitting gas from a wellhead to a burner tip. Certainly, methane gas can be compressed into cylinders, and even liquefied if necessary. However, these processes are expensive, and are only viable when gas prices are high. Natural gas in locations where no pipeline is available to carry it to market is known as “stranded” gas. Normally, it is left in the ground until some future date when a pipeline becomes available, but not always.

Natural gas that occurs without oil is called "non-associated" gas. The methane in coal seams is an example. When accompanied by petroleum it is known as "associated gas," which may occur as a free phase in the pore space of a reservoir rock, trapped above the oil. It can also be present in solution within the petroleum itself, so that when oil is brought to the surface, the gas comes with it. The dissolved gas exits from the oil under the reduced pressures at the surface and becomes a free phase.

Oil produced from the Bakken Shale in the Williston Basin of North Dakota has natural gas contents as high as one thousand cubic feet (MCF) of gas per barrel of oil (Nordeng 2010). An MCF is a volume of gas at one atmosphere of pressure and 25 degrees C filling a 10 × 10 ft room with a 10-ft high ceiling; the metric equivalent is 28.3 m^3. Pipelines are often used to transport oil, but they are not required. Oil is a liquid and it cannot be stranded like natural gas. It can go into storage tanks, and leave the production well in a tanker truck, eventually traveling by tanker train to a refinery.

One of the downfalls of the shale gas boom is that the supply of natural gas essentially doubled, while the demand for gas remained more or less constant. Following the simple laws of economics, prices dropped like a rock. Petroleum, on the other hand, is a globally-traded commodity, and the balance between supply and demand is complex and more resilient. It is also worth significantly more money than natural gas. As of this writing, a barrel of oil is worth about $40, whereas an MCF of gas sells for less than $1.50. The energy equivalence between oil and gas is about six MCF of natural gas to a barrel of oil, so the energy cost comparison is more like $40 to $7.50. No matter how it is calculated, oil is worth more money than gas. So what happens when a well produces both expensive oil and cheap natural gas in an area where there are no available pipelines to take the gas? The gas is often burned off, or flared.

The routine flaring of small amounts of produced gas was common back in the day when a visible flame called a "flambeau" was maintained on natural gas wells to prove to investors that gas was actually being produced (refer to Chap. 3). Flaring has been done on conventional wells offshore in Gulf of Mexico, in the Middle East, and elsewhere when there was no infrastructure for handling gas. In the United States, the most notable and prominent flaring has been done on the Bakken Shale play in North Dakota.

A typical Bakken well arrangement is shown in Fig. 7.3. Five pump jacks on the right side of the pad are lifting oil to the surface from five separate directional wells. On the left side of the pad are a set of tanks. The tall, narrow tanks separate the gas from the liquids in the first stage, and the oil from the produced water in the next. The shorter, wide tanks are used to store the oil and produced water until each can be hauled away. The gas is run to a far corner of the pad through a pipeline to keep it away from the flammable oil, and flared at the top of the stack.

Oil recovery from the Bakken has been remarkable. It has made North Dakota the second largest oil producing state in the U.S., surpassing other well-known oil

Fig. 7.3 Bakken Shale production wells in Dunn Co., North Dakota with gas flare at right. (Photographed in 2017 by Dan Soeder)

producers like Alaska, Oklahoma, Louisiana, and California. Only Texas remains ahead of it in first place, thanks to production from the Eagle Ford Shale and the stacked plays of the Permian Basin (Source: U.S. Energy Information Administration websites). The vast quantities of petroleum being recovered from the Bakken Shale are accompanied by equally vast quantities of natural gas that must be dealt with somehow at the wellsite.

Marketing the gas produced from the Bakken is complicated because more than just a pipeline is needed. The recovered gas is loaded with condensate, and these NGLs boost the Btu value of the gas far above the limits allowed by pipelines. So in addition to pipelines, gas plants are needed to remove the NGLs and reduce the Btu value of the gas. Pipeline companies have very strict specifications for the energy or heating value of any gas they will accept. This is because natural gas appliances and other uses for gas are engineered with the Btu value of methane in mind. Methane is the major component of natural gas, and it has an energy value of about 1000 Btu per cubic foot, or a million Btu per MCF. Allowing NGLs like propane, butane, hexane, etc. to enter the pipeline would significantly raise this Btu value and create a fire hazard in any natural gas appliances attempting to burn the gas.

Fortunately, the NGLs have value in their own right. In addition to processing the natural gas to meet pipeline specifications, a gas plant can also provide a revenue stream from the sale of propane and other condensates recovered from the gas. Because of the boom nature of gas and oil production, the gas plants are often late arrivals to the scene, and a great deal of gas may be flared before they get constructed. However, some large facilities have been brought online in North Dakota, such as the giant ONEOK Garden Creek Plant near Watford City (Fig. 7.4) that is processing substantial amounts of Bakken gas.

Flaring on Bakken wells is limited by North Dakota state laws to a maximum of one year. The state requires operators to submit gas capture plans with permit applications. These are required to include information on gas system connections and

Fig. 7.4 A small segment of the sprawling ONEOK Garden Creek Plant for processing Bakken gas near Watford City, ND. (Photographed in 2017 by Dan Soeder)

regional processing plants, a timeline for connecting the well to the midstream system, and proof that local gas processors are aware of the proposed new well (USDOE 2019).

The North Dakota Oil and Gas Research Program is a state/industry initiative of the North Dakota Industrial Commission (NDIC) that has been focusing on methods to reduce natural gas flaring by investigating small-scale processes that can be used at well sites to save the gas by compressing it, liquefying it, or creating methanol and other easily transportable materials by using gas-to-liquids technology. A parallel effort is looking into the use of miniature gas turbines for small-scale electrical generation on well pads. Power lines are run many miles to supply electricity to operate the pump jacks. If this could be generated on site, it would save money and utilize an existing resource that would otherwise be wasted (USDOE 2019).

In addition to state efforts, the federal government is trying to reduce flaring. U.S. EPA regulation 40 CFR, Part 60, Subpart OOOO requires tight oil and shale gas wells to be handled as reduced-emissions completions unless granted an exception (HEI 2019). Although this rule has been in effect since August 2011, how well it is enforced across the vast Bakken production area far from Washington, D.C. remains an open question.

Despite the presence of the Watford City gas plant and other plants in the production area, significant amounts of Bakken gas are still being flared. A rather spectacular satellite night image of the contiguous United States was released by NASA in 2017 and caused an Internet sensation when people noticed a bright “city” in the northern Great Plains where no city should exist (Fig. 7.5). The East Coast and the Great Lakes are clearly outlined in this image by their sprawling city lights, and even isolated large cities like Las Vegas, Denver, and Minneapolis-St. Paul were easily identifiable. The bright lights in North Dakota were of course the Bakken gas flares. They appeared on the satellite image to be as big and bright as Denver or Minneapolis, and actually outshone places like St. Louis and Kansas City. This was

Fig. 7.5 Satellite night image of the United States taken in 2017 that shows gas flares from Bakken Shale production wells create a bright spot as large as a major city. (Image source: NASA)

the first inkling that many people had of the vast scale of oil and gas production from the Bakken, and it was something of a thirty-day wonder.

It should be noted that a study by the Energy & Environmental Research Center at the University of North Dakota has indicated that the "Bakken flares" shown in the Fig. 7.5 satellite image have been processed and enhanced in brightness to make them more prominent and more visible. Images from space in the wavelength of light associated with combustion sources such as flares, known as the M10 band, do show numerous points of light in North Dakota linked to the Bakken flaring. It is not, however, as bright as major metropolitan areas. (https://undeerc.org/bakken/pdfs/Bakken_Flares_and_Satellite_Fact_sheet_2015.pdf accessed 6/30/2020).

Another interesting thing about the image in Fig. 7.5 is that according to people who live in western North Dakota, the flaring apparently used to be a lot worse, and it has been greatly reduced with the advent of gas processing plants. Nevertheless, a recent drive through this portion of North Dakota at night revealed multiple, towering columns of flame from numerous Bakken wells, covering 360° of horizon in some areas. The resemblance to a scene out of Dante's Inferno is notable.

The TRRC recently developed an operating metric in Texas to relate flaring to oil production known as "flaring intensity" (https://www.rrc.state.tx.us/media/56420/sitton-texas-flaring-report-q1-2020.pdf accessed 2/24/2020). The goal was to compare production performance with flaring in other states, countries, and companies. Flaring intensity in Texas is greater than that of Saudi Arabia, but less than the average for the United States, half that of Russia, and a little more than a quarter of the flaring intensity in North Dakota.

There are a number of reasons why flaring intensity can vary between oil plays, or even within plays. Some oil reservoirs have greater amounts of associated gas than others. A liquids-rich shale play like the Eagle Ford on the Gulf Coast or the stacked play in the Permian Basin are in mature locations where significant gas-handling infrastructure was put in place to handle conventional production long before shale development began. The Bakken Shale by comparison is located in a remote area of North Dakota with little pre-existing infrastructure.

7.3 Induced Earthquakes

Fracking is often linked to the occurrence of manmade earthquakes, known technically as “induced seismicity.” There are a number of incorrect assumptions folded into this statement that are worth dissecting and discussing.

Induced seismicity is, in fact, a real thing. Earthquakes are caused by movements called slippage along faults. One side of the fault slides past the other, and the motion creates several different sets of waves that pass through the Earth. These are felt as earthquakes. Natural seismicity occurs when the stresses along a fault build up to the point where they exceed the natural rock strength, and it slips. Induced seismicity results from human actions that trigger the release of these existing stresses.

The city of Denver, Colorado, normally a seismically-quiet area, began experiencing a series of unusual earthquakes in the early 1960s. The cause of these quakes was a mystery – even though many faults are present in the Denver area that date from the Laramide Orogeny, which uplifted the Rocky Mountains between about 70 and 50 million years ago (Ma), none of these had been active in the recent past. The source of the earthquakes was eventually traced to the injection of liquid waste into deep disposal wells at the nearby Rocky Mountain Arsenal (Healy et al. 1968). The liquid waste had entered existing faults and caused the pressure inside the faults to increase. Known as pore pressure, this pushed the two sides of the fracture apart, unlocking the rough spots or asperities that had previously stopped the fault from moving. As a result, the injected liquid waste triggered earthquakes.

Most of the induced seismicity ascribed to fracking is actually being caused by the injection of produced water down Class II UIC disposal wells (Llenos and Michael 2013). In a manner similar to the Rocky Mountain Arsenal earthquakes, the injected wastewater is moving into and increasing pore pressures in pre-existing faults that are under some degree of stress. A historically quiet place like central Oklahoma saw the annual frequency of seismic activity increase in 2009, with the start of wastewater injection from shale development (Fig. 7.6). Produced water from the Woodford and Fayetteville shale plays was added to the conventional O&G wastewater already using UIC wells, resulting in a series of earthquakes greater than magnitude 2.2 in Arkansas, and quakes above magnitude 3 in Oklahoma (Llenos and Michael 2013). A similar cluster of induced earthquakes in northeastern Ohio was linked to the UIC disposal of produced water from the Marcellus and Utica shales.

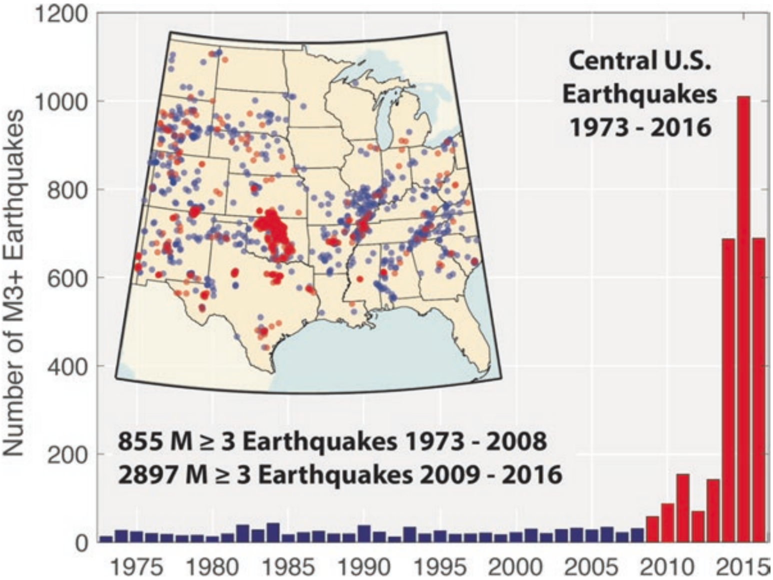


Fig. 7.6 Earthquakes above Magnitude 3 recorded in the central U.S. between 1973 and 2016, showing a dramatic increase in frequency when oilfield wastewater injection ramped up in Oklahoma after 2009. (Source: U.S. Geological Survey webpages)

The frequency of induced earthquakes in Oklahoma spiked in 2014 when record high oil prices of more than $100 per barrel led many producers to increase petroleum recovery from the older, conventional oil fields that are common in this state through the use of enhanced oil recovery (EOR) techniques. The most common type of EOR treatment is known as a waterflood. As the name implies, large amounts of water are injected into wells around the perimeter of the oil field, literally flushing the oil out of the rocks and rafting it toward central recovery wells. Substantial volumes of contaminated saltwater are flushed through the formation and recovered along with the oil. The disposal of these massive quantities of EOR wastewater down UIC wells was responsible for the 2014 spike in Oklahoma induced seismicity, not fracking. Once oil prices subsided in 2015, so did the earthquakes.

Nearly anything that changes the stress state on faults can induce earthquakes. For example, the weight of water filling up deep reservoirs after the construction of large dams has been known for some time to cause earthquakes (McCully 1996). Called reservoir-induced seismicity (RIS), it was first observed in 1932 at the Quedd Fodda Dam in Algeria, although the first systematic investigations of the possible links between seismic activity and the depth of water in an impoundment were not carried out until the 1940s by the USGS at Hoover Dam on the Colorado River. Other triggers for induced seismicity include tunneling and mining operations, oil and gas extraction, and geothermal power generation (Davies et al. 2013).

Most faults are under some degree of stress, which can gradually increase over time due to gravity, erosion, or tectonic forces. As long as this stress does not exceed the strength of the rocks, the fault will remain “locked” and immobilized. The size of the eventual earthquake that does occur when the fault finally breaks depends in a large part on just how much stress had built up across it. Different rock types have different strengths, and the induced earthquakes caused by wastewater injection seem to occur primarily on faults in relatively strong rocks like sandstone disposal formations or the granitic basement rocks below them. Shale as a rock type is generally too weak to build up much stress across faults. Although hydraulic fracturing fluids can enter and pressurize pre-existing faults in shale, there is usually a limited amount of stress to relieve if the fault slips. The large, induced earthquakes from wastewater injection down UIC wells that are felt at the surface and cause damage are rare in fracked shale.

Rare is not the same as absent, however. In the United Kingdom, multiple earthquakes in 2011 were linked to hydraulic fracturing operations in the Bowland Shale near the town of Blackpool. The largest of these had a magnitude of 2.3 and was felt locally (Clarke et al. 2014). Operations at the well site, known as Preese Hall, were suspended immediately after the seismic events, and the well was plugged and abandoned in 2013. The Bowland Shale is actually an organic-rich, shaly limestone, and the limestone component may have given the formation higher rock strength compared to clay-rich or even silica-rich shale. Greater rock strength would have allowed more stress to build up across a fault, and when frack fluids increased the pore pressure inside this fault it slipped, causing the earthquake.

As a result of these events, the U.K. has implemented the strictest regulations in the world for induced seismicity from hydraulic fracturing operations, requiring activity to cease for at least 18 hours if an induced earthquake as low as 0.5 magnitude is measured (far below anything that might be “felt”). Seven years after the Preese Hall earthquakes, fracking operations resumed under these regulations at a nearby site called Preston New Road, still targeting the Bowland Shale. Small earthquakes in October 2018 again raised public concerns. In August 2019, hydraulic fracturing operations on a well at the Preston New Road site generated 128 earthquakes, including a magnitude 2.9 event that was widely felt across the region. Operations at Preston New Road were suspended by the U.K. Oil and Gas Commission until reviews could be completed on the cause of the earthquakes and the implementation of the induced seismicity regulations. More information can be found on websites of the British Geological Survey and U.K. government. (https://earthquakes.bgs.ac.uk/research/BlackpoolEarthquakes.html)

The British Geological Survey, now considered the world’s foremost authority on fracking-induced seismicity, has identified two types of induced seismic events. “Fracked” events are caused by the brittle failure of the rock as the injection of fluid creates new fractures in a rock mass that was previously intact. These quakes are constrained by the energy of the injection process and are usually quite small, sometimes referred to as microseismic events. The second type of seismicity is known as “triggered” events. These occur when the presence of fluid and the perturbation of pre-existing faults cause them to fail. The size of these triggered events depends on the amount of stored-up elastic strain energy present in the rocks.

In North America, possible induced seismicity has been reported from hydraulic fracturing activities in Oklahoma and British Columbia. Monitoring of a test well site in Greene County, PA by the DOE National Energy Technology Laboratory detected triggered movement on a previously unidentified fault more than 600 m (2,000 ft.) above the hydraulic fracture target zone (Hammack et al. 2014). These studies have also found that hydraulic fracturing is associated with a slow-slip seismicity phenomenon called "tremor," where the rocks adjust to stress more slowly and deform in a plastic rather than brittle manner. Tremor has been described as being similar to the creaking of a floorboard, whereas a conventional earthquake is akin to the snapping of a twig.

Most studies have concluded that risks of induced seismicity from hydraulic fracturing are low for shale development in North America. However, concerns about fracking and earthquakes persist among populations in shale development areas like Pennsylvania, Ohio, and elsewhere.

References

Clarke, H., Eisner, L., Styles, P., & Turner, P. (2014). Felt seismicity associated with shale gas hydraulic fracturing: The first documented example in Europe. *Geophysical Research Letters, 41*(23), 8308–8314.

Davies, R., Foulger, G., Bindley, A., & Styles, P. (2013). Induced seismicity and hydraulic fracturing for the recovery of hydrocarbons. *Marine and Petroleum Geology, 45*, 171–185.

Hammack, R., Harbert, W., Sharma, S., Stewart, B., Capo, R., Wall, A., Wells, A., Diehl, R., Blaushild, D., Sams, J., & Veloski, G. (2014). *An evaluation of fracture growth and gas/fluid migration as horizontal Marcellus shale gas Wells are hydraulically fractured in Greene County, Pennsylvania*. NETL-TRS-3-2014; EPAct technical report series; U.S. Department of Energy, National Energy Technology Laboratory: Pittsburgh, PA, 76 p.

Healy, J. H., Rubey, W. W., Griggs, D. T., & Raleigh, C. B. (1968). The Denver earthquakes. *Science, 161*(3848), 1301–1310.

HEI (Health Effects Institute). (2019). *Human exposure to unconventional oil and gas development: A literature survey for research planning: Special report 2 (Draft for Public Comment)*: Boston, HEI-Energy Research Committee, 108 p. www.hei-energy.org

Ihlenfeld, W.J. II. (2012). *Chesapeake Appalachia pleads guilty to clean water act violations*. Press release issued by Office of the United States Attorney, Northern District of West Virginia, October 5, 2012, 1 p.

Llenos, A. M., & Michael, A. J. (2013). Modeling earthquake rate changes in Oklahoma and Arkansas: possible signatures of induced seismicity. *Bulletin of the Seismological Society of America, 103*, 2850–2861.

McCully, P. (1996). *Silenced rivers: The ecology and politics of large dams*. London: Zed Books Ltd.. 350 p.

Nordeng, S. (2010). A brief history of oil production from the Bakken formation in the Williston Basin. *GeoNews*, January 2010, North Dakota Department of Mineral Resources, *37*(1), 5–9.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

USDOE. (2019). *North Dakota natural gas flaring and venting regulations: Fact sheet*, DOE Office of Fossil Energy, Office of Oil and Natural Gas, 2 p. https://www.energy.gov/sites/prod/files/2019/08/f66/North%20Dakota.pdf

Chapter 8
Impacts to Human Health and Ecosystems

Quite a few people have been convinced for some time that fracking has detrimental impacts on both ecosystems and human health. While this may indeed be so, like most issues related to fracking and the environment, the questions are complicated and rigorous data are difficult to find. No one can positively say anything one way or the other. The body of research literature is growing, but most of the "health risks" described so far are based on anecdotal stories of people or animals getting sick, breaking out in unexplained rashes, or experiencing other health problems that appear to coincide with the fracking of nearby shale wells. In a situation similar to air, water, and landscapes, risks to ecosystems and human health come from a wide variety of sources, and fracking is only one of many. Sorting this out has been an enormous challenge.

Human health threats are assumed to be mostly from frack chemicals, but these risks are especially hard to characterize because sources, release mechanisms, transport, types of exposures, and toxicology of the potential chemicals involved are both complex and poorly understood. In terms of likely threats to terrestrial and aquatic ecosystems, shale development and fracking activities may introduce invasive species, cause habitat fragmentation, and contaminate water and air. Open impoundments on drill pads for supply water or produced water may attract wildlife, and drilling fluid, cuttings, and chemical residues left behind at well sites may contaminate water resources (Soeder and Kent 2018).

8.1 Human Health

People can be exposed to substances during conventional or unconventional oil and gas operations that have potential health risks, such as toxic chemicals or hazardous vapors. While some of these threats may be associated with hydraulic fracturing in particular, the risk potential for human health varies during different phases of

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_8

development. Procedures such as well pad construction, drilling operations, reservoir stimulation, well completion, and production each have their own sets of different risks.

Ziemkiewicz et al. (2014) at West Virginia University (WVU) examined the waste streams from Marcellus Shale development activity and concluded that drilling muds, frack fluids, and produced water all exceeded Safe Drinking Water Act standards. Although no one is actually drinking this stuff directly, it all has potential to contaminate surface water and groundwater. Pathways into the accessible environment include rips and poor anchoring of geomembrane pit liners, and construction/maintenance deficiencies on liquid transfer pipes and containment systems. The WVU investigation concluded that exposure pathways could be reduced by focusing on improved construction and maintenance efforts in the field.

The issue of exposure pathways is further complicated because the routes by which health threats can enter the environment vary from legal to accidental to criminal. Legal includes permitted emissions of vapors and gases into the air during routine operations, accidental may consist of chemical leaks or spills, and criminal is the deliberate, illegal dumping of wastes (HEI 2019). Another critical factor in exposure is the population actually at risk. Groups such as healthy, young drill rig workers may tolerate exposures much better than more vulnerable populations of small children or old people. Some investigators have recommended that epidemiological studies be used to assess the potential health effects related to fracking so that risk factors such as air and water pollution can be linked to health outcomes among nearby populations (Shonkoff et al. 2014). If all this sounds convoluted and difficult, it is.

The Health Effects Institute (HEI), a non-profit, non-government organization (NGO) in Boston has been leading efforts to assess health risks from fracking and unconventional oil and gas operations (HEI 2019). Their goal is to assess the potential health effects on populations exposed to oil and natural gas development, especially shale gas and tight oil in multiple regions of the United States. Recent work has been focused on literature reviews to determine what has been done and what is already known, and to use this knowledge to identify additional high-priority research needs. The research is proceeding in two phases: phase one is research focused on investigating the sources of health risks, and to determine how populations are being exposed. The second phase will assess the potential health impacts on various populations from different levels of exposure.

Human health risks from fracking are dependent upon the source of the risk, including the particular equipment, chemicals, and operational procedures in use at a well site. If the chemicals never leave the well site, they are not a risk to nearby populations. Thus, a second important factor is how a health threat may be released and transported from a drill site location into the community. Releases can include emissions, leaks, spills, and airborne dust, while transport pathways are commonly air, water, and workers (i.e. clothing taken home that is soiled with toxic dust or chemicals). Many companies require their workers to change clothes at the end of their shift before leaving the drill site location for precisely this reason.

Other important factors in health risks are the medium of exposure, and the exposure route. There are four major exposure routes for toxins to enter the body: inhalation, ingestion, absorption through the skin (dermal contact), and injection (directly into the bloodstream). If the exposure medium for the toxin is in air, it is likely to be inhaled. If it is in water or soil, it might be ingested, or absorbed through the skin. Exposures to chemicals may be either chronic or acute, and both have risks. A chronic, long-term exposure to a low chemical concentration can harm health differently but no less certainly than a brief, acute exposure to a high chemical concentration.

The final critical risk factor is the exposed population. This makes a huge difference in how people react to toxins, and as we have seen, to pathogens in the age of COVID. Children are usually the most sensitive to chemical exposures, because of their smaller body sizes. Older people are also at higher risk, because of possible complications from other ailments. Pregnant women make up a third high-risk group because any toxin that can cross the placenta may affect the unborn child. Healthy, young adults are usually considered the lowest-risk population, although there are some toxins and pathogens (such as the 1918 influenza outbreak) that target this particular age group as well (HEI 2019).

The air transmission route appears to be favored by many health researchers as the most likely exposure pathway for fracking-related health risks. Water may also be a critical path, but chemical spills or leaks somehow have to make it into drinking water supplies and then be ingested to pose a human health hazard. Air seems to be a more likely path because everyone has to breathe.

Air transmission has a complication because many of the chemicals and compounds researches are trying to trace, such as VOCs, NOx, methane, and other airborne vapors and gases are emitted from both unconventional and conventional oil and gas production, as well as many other sources. Linking a particular emission to fracking can be impossible, because emissions from conventional wells are often more intense than those from horizontal shale wells. Because the spacing between adjacent, conventional vertical wells is much less than that of horizontal wells (refer back to the discussion in Chap. 7), the air emissions from conventional wells are often far more concentrated. If both types of wells are in the same or adjacent areas, emissions from "fracking" might not actually be from fracked wells at all. Conventional wells also tend to be older, leading to a greater risk of leaks from deterioration of cement or casing.

As an example, a detailed air quality study on oil and gas operations in the Denver-Julesburg basin in Colorado found some of the highest VOC emissions coming from the Wattenberg Field on the western side of the basin near the city of Denver (Pétron et al. 2014). This is a large conventional gas field discovered in 1970, and it produces gas and condensate out of the Niobrara Formation from mostly vertical wells (Matuszczak 1973). At the time of the air quality study, most of the horizontal drilling and multi-stage fracking operations in the D-J basin were being done far to the northeast, in Pawnee National Grassland near the town of Raymer. Although many of the vertical wells in the Wattenberg Field had been stimulated with single-stage hydraulic fracturing treatments, the sources for the measured air emissions were identified as leakage from surface infrastructure, venting, and careless handling of produced hydrocarbons, not fracking (Pétron et al. 2014).

The frack chemicals that may be responsible for detrimental human health impacts are not well-known. A chemical must be both toxic and find an exposure route to a person in order to have an actual health effect. The intensity of the effect depends on the toxicity of the substance and whether the exposure was acute or chronic, among other things. Health effects of chemical exposures are complicated, and with fracking this is made even more so by the fact that a wide variety of chemical additives are used, many of which are new and proprietary.

The U.S. Environmental Protection Agency compiled a consolidated list of over 930 chemical compounds used or found in hydraulic fracturing fluid, including 132 chemicals present in flowback and produced water. Sources included federal and state government documents and industry-provided data (USEPA 2016). Sorting through these in terms of toxicology has been difficult. However, in actual practice, only around half a dozen or so chemicals are used in a single frack stage, making assessments much more reasonable for individual production sites (Soeder et al. 2014). The challenge is in knowing exactly what those chemicals are when the industry is reluctant to release anything other than generic information.

As described back in Chap. 6, data on the chemical additives in hydraulic fracturing fluid can be found on the FracFocus website (http://fracfocus.org/). Common substances added to frack fluid include methanol, isopropanol, crystalline silica, 2-butoxyethanol, ethylene glycol, hydrotreated petroleum distillates, sodium hydroxide, hydrochloric (muriatic) acid, ammonium chloride, ammonium and sodium persulfate, glutaraldehyde, and polyacrylamide (Soeder et al. 2014). Many of these are unpleasant, some are downright hazardous, and more than a few will vaporize or volatilize in air.

Many of the air quality investigations around fracking and production that were discussed back in Chap. 5 were focused on trying to determine potential exposures of nearby populations to airborne toxins. A typical study was the investigation by Zielinska et al. (2014) on the Barnett Shale to identify emission sources and then monitor the effects on a community. This study was limited to a small community and only lasted a month. Measurements were too brief to capture chemical concentration variations by season, development phase, operator practice, or geographic region and the study results have limited applicability. Other research investigating potential human contact with frack-related chemicals includes models and measurements for exposure routes via inhalation, ingestion, and even skin adsorption among drill rig workers. These studies are summarized in the hefty literature compilation by HEI (2019).

It turns out that the way chemical exposure is measured in the body can also influence the results. For example, chemicals like VOCs remain in the body for only hours to days before being metabolized and excreted, generally in urine. Depending on when the sample was collected, urine chemical concentrations may not reflect the actual exposure. The chemicals measured in body excretions like urine are often a breakdown product of the parent compound called a metabolite, and different parent chemicals can break down into similar metabolites, making identification of the original chemical difficult to impossible. Finally, as if this wasn't complicated enough, individuals may metabolize some of these chemicals at widely different rates, depending on genetics, medication, certain nutrients, and other factors leading to different results in the analysis. There are very limited methods to account for this.

Linking a health risk or even a specific chemical exposure to fracking is often a difficult business. Many of the targeted chemicals are present elsewhere in the environment and trying to tie a specific compound to fracking can be very challenging. A classic case is the small town of Dish, Texas, located northwest of Dallas-Ft. Worth in the Barnett Shale development area. The town's mayor blamed fracking for elevated levels of benzene that were found in blood tests run on some local citizens, and Dish became a 30-day wonder in the media and on the Internet.

In response to citizen concerns, the Texas Department of State Health Services (2010) made an effort to collect urine and blood samples from 28 residents of Dish, Texas. Tap water samples were also gathered, and investigators performed field observations of odor and noise near the subjects' homes. The location of nearby well pads, storage equipment, and compressor stations was noted. In what can only be described as a heroic effort to cross-check the data, staffers at the Texas Department of State Health Services who lived in Austin, some 150 miles (240 km) from the Barnett Shale play and 200 miles (322 km) from Dish, acted as human guinea pigs by providing blood and urine samples both before and after spending several days in Dish visiting residences near compressor stations and gas wells.

The results of the study found no difference in the benzene levels of the Health Services employees before and after the site visit. A strong correlation was found however, between elevated benzene levels in the residents of Dish and those who smoked cigarettes. Most toxicologists will readily ascribe elevated levels of benzene in blood and urine to cigarette smoking. The Texas study concluded that smoking was the cause of elevated benzene in Dish residents, not fracking. Gasoline is another major environmental source of benzene, where it is a major volatile component along with toluene, ethylbenzene, and xylenes, a combination known collectively as BTEX. The practice of self-pumping gasoline, which is common in nearly all states other than Oregon and New Jersey, can result in elevated levels of benzene in anyone who inhales the vapors or splashes gasoline onto their skin while fueling a vehicle.

Despite these findings, a later study conducted on VOC exposures of well site workers at six completion sites in Colorado and Wyoming still failed to account for smoking or other non-occupational exposures to these chemicals (Esswein et al. 2014). Urine samples were collected from workers at each site during flowback operations, which have been found to release the largest quantities of VOCs into the air during shale well completion activities (Pekney et al. 2018). The goal of the study was to try to determine how each participant's job at the site might affect VOC exposures, but by not correcting the biomonitoring results for other environmental exposures, the results were inconclusive.

An illustration of how health concerns over fracking can get out of control is the supposed contamination of the drinking water supply in the town of Pavillion, Wyoming. The story was that a production company had drilled and fracked a gas reservoir at a relatively shallow depth below the town's water supply aquifer. The water developed some taste and odor problems, and concerned citizens asked the EPA to investigate if their water supply was contaminated with frack fluid. The EPA paid a contractor to drill two monitoring wells in 2010 near the gas production site so water samples could be collected and analyzed, and samples from the new wells showed the presence of organic compounds in the groundwater that were originally linked to fracking. The media picked up on this and the story became a sensation.

Several industry investigators looked at the data and noted that the organic compounds were not the usual materials added to frack fluid. The American Petroleum Institute sponsored a subsequent investigation into the construction of the monitoring wells, and discovered that the drilling contractor had been left unsupervised by the EPA during the drilling process and had not followed specifications for installing the water quality monitoring wells. Instead of using new, clean, stainless steel casing as specified, the driller saved money by substituting recycled and painted steel casing that introduced organic materials into the aquifer. The API study concluded that the monitoring well construction itself had ended up contaminating the groundwater. The USGS followed up in 2012 by collecting, analyzing, and quality-assuring several suites of water samples from the monitoring wells (Wright et al. 2012). Without drawing any conclusions, the USGS passed the data over to the Wyoming Department of Environmental Quality (DEQ).

The Wyoming DEQ took over the investigation, and ran 11,700 additional chemical analyses on Pavillion water samples at a cost that exceeded $900,000. Cisterns were installed at a cost of $929,268 in 2014–2015 for Pavillion homeowners who did not want to continue to use the groundwater supply. The final report on the incident (Wyoming DEQ 2019) recommended that the EPA plug and abandon the two 2010 monitoring wells. The report also concluded that there is no evidence to show frack fluids rose to the depths of the water supply wells. The taste and odor problems appeared to be due to the presence of bacteria linked to declining water well yields that led to the biodegradation of naturally-occurring organic compounds in the aquifer.

The original author of the EPA study still maintains that organic compounds used for well stimulation have been detected in water samples from the two EPA monitoring wells at Pavillion, and that the concentrations of major ions in water from one of the wells provides more evidence of upward migration of frack chemicals to the depths of shallow groundwater (DiGiulio and Jackson 2016). However, given the questionable completion practices on the EPA monitoring wells, there will always be a significant degree of uncertainty in any water quality data on samples from these wells. A rigorous investigation of potential groundwater contamination at Pavillion requires that these two wells be plugged and abandoned, and that new monitoring wells be properly installed.

Wyoming is a lightly populated state with a small tax base. The nearly $2 million spent to address the Pavillion water supply "problem" was a significant expenditure. It now appears to have been unnecessary, given the findings of improper monitoring well construction and the inaccurate interpretation of laboratory data. Policy was influenced by a media circus built around the premise that greedy oil companies are willing to heedlessly poison innocent citizens just to make a profit. This is a Hollywood fantasy; despite episodes like the Exxon Valdez and the Deepwater Horizon, large, multinational oil companies are shareholder-owned corporations that seek to limit their financial liabilities from irresponsible or reckless behavior.

Examples like Dish and Pavillion illustrate just how difficult it can be to link health risks to fracking. Monitoring is difficult and expensive, and must be run over long time periods to establish exposure baselines. Concentrations of contaminants can vary across time and space, even across the width of a drill pad, and between different locations. A well-designed monitoring study must be able to account for both acute, short-term exposures and chronic, longer term exposures.

Given these challenges, a number of researchers have turned to numerical modeling studies in an attempt to predict the risk of exposure under various conditions (i.e. Benedict et al. 2018). These are not done in a vacuum, but include monitoring data when available. Some of the models are quite elaborate, incorporating location, activity patterns over time, and protective measures taken for local populations when assessing air quality data and quantifying exposures to VOCs (Bloomdahl et al. 2014). Many of the modeling studies have attempted to include and delineate the various components that led to elevated concentrations of pollutants in the air. For example, models of ozone generation from VOCs released during fracking operations attempted to account for meteorological conditions, because the creation of ground level ozone requires not only VOCs, but also sunlight, light winds, and temperature inversions (Bien and Helmig 2018; Nsanzineza et al. 2019). Other models investigated the different types of chemical exposures that might occur during specific wellsite operations and activities (Bean et al. 2018).

The Institute of Medicine (IOM) convened a workshop in 2012 called the Roundtable on Environmental Health Sciences, Research, and Medicine to explore impacts of shale gas development and hydraulic fracturing on public health issues in communities and on workers employed in the industry (Institute of Medicine 2014). The workshop produced a report that summarized the state of the science on shale gas development in 2012, and detailed what was known about both the direct and indirect environmental health risks (Institute of Medicine 2014). They were unable to identify any direct health risk from the fracking process that was more severe than conventional oil and gas well drilling.

The IOM workshop was organized in part because the government public health system had not been active in discussions about shale gas extraction, and many public health physicians were worried that the potential environmental health impacts of these technologies were not being addressed or regulated. In fact, it wasn’t until an Executive Order was issued by President Obama in April 2012 that the U.S. Department of Energy, the U.S. Geological Survey and the U.S. Environmental Protection Agency began to pool resources and knowledge to assess the environmental risks of shale development (USDOE 2015). The EPA was charged with investigating the environmental receptors of fracking chemicals, and realized that humans are of course one of these receptors. The Department of Health and Human Services and the National Institutes of Health were engaged to assist with the public health aspects of the assessment.

The Health Effects Institute has attempted to explore and list the knowledge gaps that remain concerning potential human health risks from shale gas extraction and fracking. These fall under the three broad categories of (1) risk sources, (2) transport pathways, and (3) exposed populations (HEI 2019). Each is described in the paragraphs that follow.

Risk Sources Little is known about the probability of environmental releases of hazardous materials from unconventional, fracked well sites. Risk of release varies over time and between locations because of differences in geology, changes in meteorological conditions, and the adoption of different practices by different operators. It can also change due to technological innovations, changing regulations, and operator response to community concerns. For a true risk assessment, the uncertainty needs to be replaced with a probability function that defines the likelihood, composition, magnitude, frequency, and duration of releases. This will help quantify the potential for emissions or leakage/spills from different stages in the shale gas development process.

Environmental monitoring of risk sources would be simplified if some indicator chemicals, such as methane in air or TDS in water could be used as predictors of other releases. Long-term emission trends from sources could be monitored with ground-based or satellite historical observations. The mechanism by which a chemical is released into the air or water must be better understood, be it operational, accidental, or illegal.

Transport Pathways Variations in local conditions such as meteorology, topography, geochemistry, and hydrology can affect the movement of frack chemicals in air and water. Some conditions vary over time intervals ranging from hourly to seasonally, and control how gases, vapors and liquids might move from a well site to expose a nearby population. It is critically important to obtain pre-drilling baseline data, especially on air and groundwater to distinguish fracking chemicals from other natural and anthropogenic sources.

An intervention on a transport pathway can stop human populations from being exposed to potential fracking health risks. For example, keeping a leaking toxic chemical from trickling into a stream that is used for drinking water will prevent many health impacts. Closing a vent to stop VOCs from entering the air during a temperature inversion can prevent the build-up of smog and ozone. In order for this to work however, the transport pathways must first be identified. If released chemicals can be contained and kept away from vulnerable populations, health risks will be reduced substantially.

Exposed Populations This is perhaps the most complicated assessment of the three categories of human health risks. Different behaviors can have a substantial influence on how individuals react to potential exposure to frack chemicals. Smoking, alcohol consumption, use of certain drugs, poor eating habits, vitamin deficiencies and many other factors can affect how a person reacts to a chemical. Although one might expect the rig workers to be the primary exposed group because they are closest to the activity, they tend to be robust and young, and may not be the most strongly affected. This could perhaps be addressed by assessing workers in other industries that might be exposed to similar chemicals as a baseline to normalize the results. The highest risk populations are not likely to be health young workers however, but the very young, the very old, and those who are sick, chronically ill, or otherwise health-compromised.

The size and makeup of the exposed population is not well-understood. There should be less exposure with greater distance from the drill rig, but in many cases, this may depend on the specific toxicity of the substance released and the transport path. For example, populations along the route to a disposal well could be exposed to frack chemicals leaking from the haulage trucks, even though they may be located quite distant from the fracking site. Sub-groups such as small children, pregnant women, and ailing older people may react more adversely to exposures than the general population of healthy, younger people.

Exposure monitoring methods need long-term study designs, dedicated instrumentation, and possibly new technologies to more accurately characterize population exposures to toxic chemicals from unconventional oil and gas development. Other potential health risks to nearby populations may include noise, vibration, and bright lights on the worksite during drilling, fracking, and production operations. These activities can result in elevated stress levels and a lack of sleep for affected nearby residents, and have been largely un-investigated.

Researchers outside of North America have made the case that differences in cultures, demographics, geology, and regulations invalidate the use of U.S. evidence concerning the environmental and health risks of shale development and fracking in places like the European Union (Prpich and Coulon 2018). The authors recommend that Member States of the EU fund and carry out their own research, and not rely on U.S. results. Investigations in Europe should focus on developing comprehensive environmental baselines and filling existing gaps in human health studies to assess population exposure risk prior to the potential development of European shale resources. This argument has some validity, and could be applied to other nations as well. Thus, countries wishing to develop their own shale resources, such as China, Australia, Pakistan, Argentina, etc. should run national assessments based on risk factors related to contaminant sources, transport pathways, and exposed populations that are unique to each nation.

A firm in Washington, D.C. called Resources for the Future (RFF) recently attempted to produce a review of the scientific literature to summarize the state of the science for health effects from fracking (Krupnick and Echarte 2017). They concluded that the existing technical literature does not provide any strong evidence linking fracking to specific health impacts. This agrees with similar conclusions from the Institute of Medicine workshop (Institute of Medicine 2014), the federal multi-agency assessment (USDOE 2015), and preliminary findings of the Health Effects Institute (HEI 2019). The RFF report also stated that the scientific literature has not established workable exposure routes and toxicology by which fracking could result in potential health effects, and concluded that no immediate public health action is needed. However, given the vast amount of uncertainty, the RFF study recommended that detailed exposure monitoring be expanded, and include the systematic analyses of health effects on residents living near oil and gas operations (Krupnick and Echarte 2017).

As stated back in Chap. 1 in the discussion about concepts of risk, the absence of evidence is not evidence of absence. This is especially true for health effects, which can sometimes take years or decades to become apparent (for example: cigarette smoking, DDT, Agent Orange, PCBs, lead-based paint, and asbestos, to name a few). Despite the fact that no direct connections between fracking and negative human health effects have been found so far, it would be foolish to conclude that none exist. The level of uncertainty requires that these issues continue to be investigated. Communities, physicians, regulators, the O&G industry, and others can benefit from an improved understanding of the potential exposures to chemicals and other agents from fracking that may produce adverse health effects. As the saying goes, knowledge is power.

8.2 Terrestrial Ecosystems

Impacts of shale development and fracking on terrestrial environments are primarily related to the large amounts of land disturbance caused by the construction of drill pads, roads, and pipeline rights-of-way. There are both short-term and long-term effects.

The construction activity of the wells is relatively short-term, but it can be very disruptive to local wildlife. The noise, lights and constant activity will drive most wildlife away, and the animals may take months to return to the habitat after the rigs and equipment are gone. This is a concern in state forests and other wildlife-rich areas. The well installation activity may drive territorial animals in particular into the territories of their neighbors, and there can be many years of disruption in mating patterns and other behavior until boundaries become re-established. The lights can be very disorienting to birds, and mid-flight crashes into the lit-up derrick or mast are not uncommon.

Impoundments on well pads for fracking water supplies often provide what is called an “attractive nuisance” that may draw ducks, geese, and other waterfowl. As long as the pond is filled with just water, it is not harmful to the birds or other wildlife. However, with the practice of flowback recycling, these ponds may contain toxic organic compounds and high TDS brines from produced water that may pose a risk to waterfowl. The ponds may also attract other animals like deer that come to drink.

Impoundments are often maintained on drill pads for long time periods, sometimes years, if the operator thinks there might be a need to re-frack the well. When the initial fracking takes place, fractures grow in the direction of maximum principal stress. However, there is no open space underground, and creating a fracture in one direction causes stress fields to change in other directions. The hydraulic fracturing process starts with the fractures moving into the rock at right angles to the horizontal wellbore, but as stress fields change underground to accommodate the new opening, the crack often turns and runs parallel to the wellbore. This is very inefficient for recovering gas, and the frack operation is halted. After the stress field adjusts and the rock has had time to accommodate the stresses, a second frack treatment is performed months to years later to extend the cracks farther into the reservoir at right angles to the borehole.

Re-fracking is expensive, mostly because of the mobilization costs incurred when virtually everything in terms of equipment and supplies has to be brought back out to the well pad for a second attempt. Many operators avoid it by performing a “zipper frack,” which uses two parallel boreholes. The fracks are alternated between the two holes zone by zone, and the stress produced by one is accommodated by the other. With the advent of zipper fracking, re-fracking has become much less common, and many water impoundments are now dismantled after the wells are completed. Even when a re-frack is required, operators will typically breach the impoundment so that it will not hold water during the period of stress re-adjustment. This helps protect them from the legal liability of having an attractive nuisance on their well pad. The breach is repaired when needed to accumulate a water supply for re-fracking.

Chemical additives on drill pads during fracking operations can prove to be harmful or fatal to both wildlife and domestic animals if there are leaks or spills and the chemicals enter the environment. A photograph was circulated widely by fracking opponents a decade ago that showed a dead cow next to a fracking operation in the Haynesville Shale where biocide had leaked from a tank on the pad and flowed into the nearby pasture. The cow lapped it up and was soon deceased (Fig. 8.1). These types of events are rare, but do happen. Other pictures of dead cattle near fracking sites can be found by searching the Internet.

Some frack additives like ethylene glycol are sweet and attractive to animals. It is important for operators to maintain control of their inventories of the chemical additives, not bring more on-site than is actually needed, and monitor the activities of wildlife, domestic animals, and people in the areas surrounding the well pad. Given the 24-hour nature of fracking operations, activity on the pad is likely to be continuous and wildlife normally stays away. However, many of these wells are in very remote, rural locations. The woods and pastures surrounding the pads may attract various animals, sometimes with tragic results.

A source of long-term degradation to an ecosystem may result from the fragmentation of habitat crisscrossed by roads and pipelines. Fragmentation is a process where large expanses of habitat are transformed into multiple, smaller patches that are isolated from each other by barriers composed of habitats much different than the original (Hagen et al. 2012). For example, excavating a wide road through a forest will separate two previously joined expanses of forest habitat with a line of packed dirt that is definitely not forest habitat. Some plants and animals in the ecosystem can cross this boundary easily, but it may present an insurmountable barrier to others. Different species are affected in different ways, depending on factors like body size, ability to disperse, and other spatial, temporal, or biotic drivers. Because

Fig. 8.1 A dead cow that drank biocide leaking from an adjacent Haynesville Shale fracking operation in 2009. (Source: ProPublica webpages; original image Shreveport Times, public domain)

biodiversity relies on the complex interactions of various species within an ecological network, the effects of habitat fragmentation can extend well beyond just the species that are unable to cross the boundary. Habitat fragmentation can degrade the operation of an entire ecosystem because of the way patterns and processes are networked. Fragmentation can lead to species dispersal, colonization, or extinction depending on network structure and co-evolutionary dynamics (Hagen et al. 2012).

Another potential impact from fracking on terrestrial ecosystems is the introduction of invasive species into new habitats. Drill rigs, trucks, cranes, and earthmoving equipment have been moved across the country multiple times to drill and frack wells from Texas to North Dakota to Pennsylvania. Plants and animals hitchhiking along with any of this gear may have ended up being deposited in new habitats. No one has yet reported armadillos in West Virginia, for example, but the possibility exists. Invasive species are often able to establish a firm foothold in a new territory before being recognized.

Species that end up in a new area where they have no natural enemies are prone to reproduce out of control and damage the environment for existing species. Invasive species are sometimes introduced deliberately, such as the South American nutria (*Myocastor coypus*) a muskrat-like mammal brought in to Louisiana by fur farmers in the 1920s. The critters managed to escape into the swamps and breed copiously, causing significant damage to wetlands all along the Gulf and East Coasts. They have now made their way as far north as the Chesapeake Bay. Other invasive species have been introduced inadvertently, like zebra mussels (*Dreissena polymorpha*) native to the lakes of southern Russia and Ukraine. They became established in Lake St. Clair (between Lakes Huron and Erie) in 1988, presumably from the ballast water expelled by international ships transiting the St. Lawrence Seaway. With no natural predators, zebra mussels soon spread throughout the Great Lakes, clogging water intakes and biofouling docks and ship bottoms.

It is not known if any invasive species have been introduced by the movement of drill rigs and associated equipment from place to place across the country. Although this site-to-site movement happens all the time, during the shale boom it was much more frantic, and crews were being less careful about how equipment was cleaned and inspected before traveling to a new geographic area. Since invasive species often take years to decades to become established and noticeable, it may be some time yet before we know if this is a problem.

A final issue related to fracking and terrestrial ecosystems is known as "ecological succession." This is essentially how an ecosystem rebuilds to infill an area that had been cleared by fire, bulldozers, or other means. There are two types of succession: primary and secondary. Primary succession occurs on entirely new habitat that has never before been colonized, like a freshly quarried rock face or sand dunes. Secondary succession refers to the process of ecosystem rebuilding in previously occupied habitat that has been disturbed or damaged, for example by clearcutting timber or by a forest fire.

Drill pads designed for shale wells and fracking are typically constructed by clearing topsoil from approximately five acres (2 hectares) of land, laying down a heavy, impervious "geomembrane" to prevent any leaks or spills from infiltrating into the ground, and then covering the geomembrane with a layer of gravel nearly a foot (30 cm) thick. Any ecosystem attempting to re-colonize this constructed, unoccupied surface area would essentially be undergoing a primary succession.

The process of re-colonization results in the organisms interacting with and affecting the physical and chemical environment. As the environment changes, the species in the area gradually change with it. Because each species is adapted to thrive under a specific set of environmental conditions, if these change a different set of species that are better adapted will out-compete the existing species. Succession passes through a number of stages known as "seres." Each sere merges gradually into the next until the final stage, called the climax community, is reached. This is the end of the succession. Succession occurs on many different timescales, ranging from a few days to hundreds of years. Even in the climax community, things are not static. When trees die and fall, for example, new openings are created for secondary succession to occur.

The question related to fracking is how do drill pads, roads, and pipeline access rights-of-way affect succession? If left alone, a drill pad will become overgrown with grass, brush, and finally trees over a period of months to years. However, if the production site remains active, the ecology will not re-establish. Shale wells drilled along the south shore of Lake Erie in the nineteenth century to supply individual farms produced natural gas for decades, and some even remained productive for a century or longer (Soeder 2017). It is not known how this might apply to modern horizontal shale wells, but it is possible they could be productive for a long time.

The need for continuous, periodic visits to the pad for maintenance and other activities will require that at least some of the cleared area be kept clear, and will preclude succession. It may be possible to substantially shrink the initial five-acre (2 hectare) pad size down to just those areas needed to provide access for production and maintenance activities like the wellheads, produced water tanks, compressor, and metering line. In this case, most of the pad can be allowed to return to a climax ecology. However, if an operator intends to re-frack the wells at some future date, access to the entire pad would be needed to accommodate the large amount of equipment and materials. The costs of having to re-clear brush and trees from an overgrown five acre pad for a re-frack might be considerably higher than the routine cost of just maintaining it during periodic visits until a re-frack can be accomplished. In this case, ecological succession will be put on hold until there is no longer a need for the large pad.

The techniques applied to the management of these large, cleared drill pad areas over time on different shale plays in different parts of the country can have an impact on the local ecology. How ecological succession proceeds under different approaches could provide valuable insights for ecologists monitoring this process around construction sites, abandoned buildings, and other infrastructure.

8.3 Aquatic and Marine Ecosystems

Along with degradation of aquatic ecosystems from surface spills of frack chemicals or produced fluids, the main impact shale gas development has on streams is to affect runoff from the increase in impervious surface area in small watersheds. A study done in Maryland a number of years ago found that once about 10% of the surface area in a watershed becomes impervious (i.e., roads, rooftops, driveways, parking lots, etc.), the stream biota undergo shifts in population, reductions in diversity, and reduced population density. The 10% threshold seems to be the point at which storm water runoff events become too intense for normal aquatic ecosystems, and declines in population are observed (Barnes et al. 2002).

A runoff modeling study at the DOE National Energy Technology Laboratory (NETL) assumed that a single drill pad and associated access roads add about 3.25 hectares (8 acres) of impervious surface area to a watershed (Soeder 2017). The model outputs showed that impacts to a stream varied with catchment area and land use type. The least impaired land use type is forest, and the threshold for stream impact from a single drill pad in a forested watershed occurs when the catchment area is 5 square km (2 square miles) or less. Other land use types already have some degree of hydrologic impairment, so the threshold for stream impacts from a single drill pad on these lands will affect a larger catchment area. Stream impact thresholds for drill pads on agricultural land were found to affect catchment areas of 6.5 square km (2.5 square miles), and streams were impacted when a drill pad was placed on urbanized land within a catchment area of 13 square km (5 square miles).

With a few notable exceptions like the Barnett Shale development in the urbanized Dallas-Ft. Worth area, most shale gas well pads are located in rural areas that are forested or agricultural. The impact to watersheds of placing drill pads and associated infrastructure on these lands are not completely understood. Certainly, replacing eight acres of water-absorbing forest with eight acres of impervious surface will probably degrade nearby water resources. However, placing a drill pad on agricultural land may have less of an impact, and could even lead to a slight ecosystem improvement by displacing some of the area previously contributing chemical pesticides and fertilizers to streams and groundwater. In an urbanized area, replacing an impervious parking lot with an equal-size impervious drill pad should have no significant effect at all.

The NETL assessment was done using only numerical models. Some on-the-ground measurements in a variety of different land use areas would help to provide rigorous data on the potential impacts of drill pads on small watersheds and aquatic ecosystems. High-intensity storm water runoff is exceedingly stressful to aquatic biota, and an ecosystem can require a substantial length of time to re-establish after such an event. Another important consideration is that as drilling technology improves, the pads are being spaced farther apart and the watershed impacts will be different depending on when the pad was constructed. These historical changes in well spacing must be considered in any field-based study. Environmental monitoring of shale well leases on state forest land in Pennsylvania has been carried out by state agencies, and these data could be helpful in developing more robust models of the hydrologic impacts of well pads on small watersheds in forested lands (Pennsylvania Bureau of Forestry 2018).

The number of horizontally-drilled shale gas and tight oil wells in the United States has increased in a decade from roughly 28,000 in 2007 to approximately 127,000 in 2017 (Mumford et al. 2020). There is at least some empirical evidence reported by investigators at Penn State (Brantley et al. 2014) that the development of shale gas resources has affected nearby stream ecosystems. Several recent investigations by the USGS have looked in detail at the potential impacts to groundwater, streams and aquatic ecosystems from fracking and other shale gas activities. In most cases, few significant links have been found (i.e. McMahon et al. 2015, 2016, 2017, 2019).

When surface water contamination does occur, the origins are usually not mysterious. For example, a UIC well in West Virginia used for the disposal of produced water from the Marcellus Shale was found to be causing impacts to a nearby stream (Akob et al. 2016). The contamination had little to do with the UIC well or the injection process itself, but was primarily caused by careless handling of the produced water, resulting in spills from the trucks and leaks from loose plumbing connections that were then getting into the creek. In another case, a North Dakota stream was contaminated from a ruptured pipeline carrying Bakken produced water to a disposal well (Cozzarelli et al. 2017). These incidents can cause serious disruptions to local aquatic ecosystems when they do happen, but fortunately they are infrequent.

The discharge of high-salinity produced water into streams during the early days of the shale gas boom (2008–2012) caused noticeable declines in aquatic life. Freshwater mussels, an endangered and protected species, were particularly affected (Patnode et al. 2015). USGS measurements of mussel mortality combined with conductivity measurements in the Allegheny River downstream from POTW outfalls and brine treatment facilities showed a significant population drop attributed to the discharge of high TDS produced water. Changes in water management procedures including the recycling of flowback and disposal of residual waste down UIC wells were critical to the survival of native mussel populations in this river.

A detailed USGS study was carried out on 25 different small watersheds in the Marcellus Shale gas development area of Pennsylvania to evaluate geochemical and biological effects on streams (Mumford et al. 2020). The intent of this project was to comprehensively test the hypothesis that quantifiable, significant links exist between increased density of shale gas development and greater amounts of fracking-associated chemical compounds in stream water, with associated negative impacts to aquatic ecosystems.

Measurements were made over a period of 2 years to account for the seasonal variability of geochemical parameters, and numerous watersheds were sampled to cover a cross-section of shale gas development intensity. The USGS investigation found that no statistically significant relationship exists between the presence or absence of fracked shale wells and any specific chemicals in the streams, including those recognized as oil and gas "indicators." The results showed no significant effects on the microbial or benthic macroinvertebrate communities either (Mumford et al. 2020).

Several factors may account for the difference in the findings of the Brantley et al. (2014) Penn State investigation, which did find some stream impacts from fracking, and the USGS study by Mumford et al. (2020) which did not find any impacts statistically associated with Marcellus wells. The USGS study was done randomly over a large area to obtain a statistically significant sample across a gradient of Marcellus Shale development activity. The Penn State investigation was focused on watershed impacts from reported incidents of spills associated with Marcellus Shale wells and fracking. Also, the Penn State study was carried out prior to 2014 during the tail end of the fracking boom in Pennsylvania. The USGS work was done 5 years later under much less frantic drilling schedules and with far more experienced rig crews who were presumably less prone to accidents.

In any event, these types of investigations provide a framework for assessing the intensity of environmental impacts from the anthropogenic development of natural resources, and suggest an approach for conducting statistically-valid studies that control variability across land regions and through time. Substantial natural variability in stream chemistry and biota with the seasons and with sampling location shows the importance of collecting baseline data prior to the start of fracking activities in a watershed. The natural geochemical and biological variability of headwater streams must be established before the impacts of fracking can be isolated and measured.

Trying to separate the effects of an anthropogenic activity like fracking from natural spatial and temporal variability in water chemistry and biology is a major challenge. It is more complicated in places like Pennsylvania or Ohio where a long history of legacy anthropogenic activities affect streams. Everything from railroad construction to coal mining has left impacts that may mask or mimic any signal from fracking against the natural background. The type of comprehensive, integrated study performed by Mumford et al. (2020) is required to understand the effects of fracking and shale gas development on watersheds at regional scales.

Fracking is used offshore to improve the performance of conventional wells. Although there have been no documented impacts to marine life or ecosystems so far, flowback and produced water are commonly disposed of expediently by dumping into the ocean (Sakashita 2014). Some offshore injection wells do exist, but these are virtually impossible to monitor. Because of the potential risk to marine ecosystems, environmental advocates have been calling for offshore fracking to be banned, or to at least require that these fluids be brought to shore and disposed of down Class II UIC wells just like other oilfield brines. Because of the added cost, industry response has been less than enthusiastic.

References

Akob, D. M., Mumford, A. C., Orem, W., Engle, M. A., Klinges, J. G., Kent, D. B., & Cozzarelli, I. M. (2016). Wastewater disposal from unconventional oil and gas development degrades stream quality at a West Virginia injection facility. *Environmental Science & Technology, 50*, 5517–5525.

Barnes, K. B., Morgan III, J. M, & Roberge, M. C. (2002). *Impervious surfaces and the quality of natural and built environments*. Department of Geography and Environmental Planning, Towson University, Baltimore, MD, 21252-0001, 28 p.

Bean, J. K., Bhandari, S., Bilotto, A., & Hildebrandt Ruiz, L. (2018). Formation of particulate matter from the oxidation of evaporated hydraulic fracturing wastewater. *Environmental Science & Technology, 52*(8), 4960–4968.

Benedict, K. B., Prenni, A. J., Sullivan, A. P., Evanoski-Cole, A. R., Fischer, E. V., Callahan, S., Sive, B. C., Zhou, Y., Schichtel, B. A., & Collett, J. L., Jr. (2018). Impact of front range sources on reactive nitrogen concentrations and deposition in Rocky Mountain National Park. *Peer Journal, 6*, e4759. https://doi.org/10.7717/peerj.4759.

Bien, T., & Helmig, D. (2018). Changes in summertime ozone in Colorado during 2000–2015. *Elementa-Science of the Anthropocene, 6*(1), 55. https://doi.org/10.1525/elementa.300.

Bloomdahl, R., Abualfaraj, N., Olson, M., & Gurian, P. L. (2014, November). Assessing worker exposure to inhaled volatile organic compounds from Marcellus shale flowback pits. *Journal of Natural Gas Science and Engineering, 21*, 348–356.

Brantley, S. L., Yoxtheimer, D., Arjmand, S., Grieve, P., Vidic, R., Pollak, J., Llewellyn, G. T., Abad, J., & Simon, C. (2014). Water resource impacts during unconventional shale gas development: The Pennsylvania experience. *International Journal of Coal Geology, 126*, 140–156.

Cozzarelli, I. M., Skalak, K. J., Kent, D. B., Engle, M. A., Benthem, A., Mumford, A. C., Haase, K., Farag, A., Harper, D., Nagel, S. C., Iwanowicz, L. R., Orem, W. H., Akob, D. M., Jaeschke, J. B., Galloway, J., Kohler, M., Stoliker, D. L., & Jolly, G. (2017). Environmental signatures and effects of a spill of untreated oil and gas wastewater in the Williston Basin, North Dakota. *Science of the Total Environment, 579C*, 1782–1795. https://doi.org/10.1016/j.scitotenv.2016.11.157.

DiGiulio, D. C., & Jackson, R. B. (2016). Impact to underground sources of drinking water and domestic wells from production well stimulation and completion practices in the Pavillion, Wyoming, field. *Environmental Science & Technology, 50*(8), 4524–4536.

Esswein, E. J., Snawder, J., King, B., Breitenstein, M., Alexander-Scott, M., & Kiefer, M. (2014). Evaluation of some potential chemical exposure risks during flowback operations in unconventional oil and gas extraction: Preliminary results. *Journal of Occupational and Environmental Hygiene, 11*(10), D174–D184.

Hagen, M., Kissling, W. D., Rasmussen, C., De Aguiar, M. A. M., Brown, L. E., Carstensen, D. W., Alves-Dos-Santos, I., Dupont, Y. L., Edwards, F. K., Genini, J., Guimarães, P. R., Jr., Jenkins, G. B., Jordano, P., Kaiser-Bunbury, C. N., Ledger, M. E., Maia, K. P., Darcie Marquitti, F. M., Mclaughlin, Ó., Morellato, P. C., O'Gorman, E. J., Trøjelsgaard, K., Tylianakis, J. M., Morais

Vidal, M., Woodward, G., & Olesen, J. M. (2012). Biodiversity, species interactions and ecological networks in a fragmented world. *Advances in Ecological Research, 46*, 89–210.

HEI (Health Effects Institute). (2019). *Human exposure to unconventional oil and gas development: A literature survey for research planning: Special report 2 (Draft for Public Comment)*: Boston, HEI-Energy Research Committee, 108 p. www.hei-energy.org

Institute of Medicine. (2014). *Health impact assessment of shale gas extraction: Workshop summary*. Washington, DC: The National Academies Press, 154 p. https://doi.org/10.17226/18376.

Krupnick, A. J., & Echarte, I. (2017). *Health impacts of unconventional oil and gas development*. Washington, DC: Resources for the Future (RFF). 32 p.

Matuszczak, R. A. (1973). Wattenberg field, Denver Basin, Colorado. *The Mountain Geologist, 10*(3), 99–105.

McMahon, P. B., Caldwell, R. R., Galloway, J. M., Valder, J. F., & Hunt, A. G. (2015). Quality and age of shallow groundwater in the Bakken formation production area, Williston basin, Montana and North Dakota. *Groundwater, 53*, 81–94.

McMahon, P. B., Kulongoski, J. T., Wright, M. T., Land, M. T., Landon, M. K., Cozzarelli, I. M., Vengosh, A., & Aiken, G. R. (2016). *Preliminary results from exploratory sampling of wells for the California oil, gas, and groundwater program, 2014-15*. U.S. Geological Survey Open-File Report 2016-1100, 8 p. https://doi.org/10.3133/ofr20161100.

McMahon, P. B., Barlow, J. R. B., Engle, M. A., Belitz, K., Ging, P. B., Hunt, A. G., Jurgens, B. C., Kharaka, Y. K., Tollett, R. W., & Kresse, T. M. (2017). Methane and benzene in drinking-water wells overlying the Eagle Ford, Fayetteville, and Haynesville shale hydrocarbon production areas. *Environmental Science & Technology, 51*(12), 6727–6734.

McMahon, P. B., Lindsey, B. D., Conlon, M. D., Hunt, A. G., Belitz, K., Jurgens, B. C., & Varela, B. A. (2019). Hydrocarbons in upland groundwater, Marcellus shale region, northeastern Pennsylvania and southern New York, USA. *Environmental Science & Technology*, Online Publication Date: 27 June 2019. https://doi.org/10.1021/acs.est.9b01440

Mumford, A. C., Maloney, K. O., Akob, D. M., Nettemann, S., Proctor, A., Ditty, J., Ulsamer, L., Lookenbill, J., & Cozzarelli, I. M. (2020). Shale gas development has limited effects on stream biology and geochemistry in a gradient-based, multiparameter study in Pennsylvania. *Proceedings of the National Academy of Sciences, 117*(7), 3670–3677. https://doi.org/10.1073/pnas.1911458117.

Nsanzineza, R., Capps, S. L., & Milford, J. B. (2019). Modeling emissions and ozone air quality impacts of future scenarios for energy and power production in the Rocky Mountain states. *Environmental Science & Technology, 53*(13), 7893–7902.

Patnode, K. A., Hittle, E., Anderson, R. M., Zimmerman, L., & Fulton, J. W. (2015). Effects of high salinity wastewater discharges on Unionid mussels in the Allegheny River, Pennsylvania. *Journal of Fish and Wildlife Management, 6*(1), 55–70.

Pekney, N., Reeder, M., & Mundia-Howe, M. (2018). Air quality measurements at the Marcellus shale energy and environment laboratory site. *EM The Magazine for Environmental Managers*, August 2018, Air & Waste Management Association, 5 p.

Pennsylvania Bureau of Forestry. (2018). *Shale gas monitoring report*. Harrisburg, PA: PA Department of Conservation & Natural Resources. 199 p.

Pétron, G., Karion, A., Sweeney, C., Miller, B. R., Montzka, S. A., Frost, G. J., Trainer, M., Tans, P., Andrews, A., Kofler, J., Helmig, D., Guenther, D., Dlugokencky, E., Lang, P., Newberger, T., Wolter, S., Hall, B., Novelli, P., Brewer, A., Conley, S., Hardesty, M., Banta, R., White, A., Noone, D., Wolfe, D., & Schnell, R. (2014). A new look at methane and non-methane hydrocarbon emissions from oil and natural gas operations in the Colorado Denver-Julesburg Basin. *Journal of Geophysical Research-Atmospheres, 119*, 6836–6852.

Prpich, G., & Coulon, F. (2018). Assessing unconventional natural gas development: Understanding risks in the context of the EU. *Current Opinion in Environmental Science & Health, 3*, 47–51.

Sakashita, M. (2014). *Troubled waters: Offshore Fracking's threat to California's ocean, air and seismic stability*. Tucson: Center for Biological Diversity. 6 p.

Shonkoff, S. B., Hays, J., & Finkel, M. L. (2014). Environmental public health dimensions of shale and tight gas development. *Environmental Health Perspectives, 122*, 787–795. https://doi.org/10.1289/ehp.1307866.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Kent, D. B. (2018). When oil and water mix: Understanding the environmental impacts of shale development. *GSA Today, 28*(9), 4–10.

Soeder, D. J., Sharma, S., Pekney, N., Hopkinson, L., Dilmore, R., Kutchko, B., Stewart, B., Carter, K., Hakala, A., & Capo, R. (2014). An approach for assessing engineering risk from shale gas wells in the United States. *International Journal of Coal Geology, 126*, 4–19.

Texas Department of State Health Services. (2010). *Dish, Texas exposure investigation: Dish, Denton County, Texas*. Final Report, 36 p.

USDOE. (2015). *Report on the multiagency collaboration on unconventional oil and gas research*, USDOE Office of Fossil Energy, Report to Congress on behalf of the Multiagency Collaboration (MAC), December 2015, 24 p.

USEPA. (2016). *Hydraulic fracturing for oil and gas: Impacts from the hydraulic fracturing water cycle on drinking water resources in the United States (Final Report): EPA/600/R-16/236F*, Washington, DC, 664 p.

Wright, P.R., McMahon, P.B., Mueller, D.K., & Clark, M.L. (2012). *Groundwater-quality and quality-control data for two monitoring wells near Pavillion, Wyoming, April and May 2012*. U.S. Geological Survey Data Series 718, 23 p. (Revised October 2012).

Wyoming DEQ (Department of Environmental Quality). (2019). *Final Pavillion, Wyoming gas field domestic water wells report on recommendations for further investigation*. Cheyenne: Wyoming DEQ Water and Waste Advisory Board. 45 p. http://deq.wyoming.gov/wqd/pavillion-investigation/resources/investigation-final-report/.

Zielinska, B., Campbell, D., & Samburova, V. (2014). Impact of emissions from natural gas production facilities on ambient air quality in the Barnett shale area: A pilot study. *Journal of the Air & Waste Management Association, 64*, 1369–1383. https://doi.org/10.1080/10962247.2014.954735.

Ziemkiewicz, P. F., Quaranta, J. D., Darnell, A., & Wise, R. (2014, January). Exposure pathways related to shale gas development and procedures for reducing environmental and public risk. *Journal of Natural Gas Science and Engineering, 16*, 77–84. https://doi.org/10.1016/j.jngse.2013.11.003.

Chapter 9
Fossil Fuels and Climate Change

Burning fossil fuels for energy produces waste gases known as "combustion products," which are, with few exceptions, released directly into the atmosphere through smokestacks, chimneys, and exhaust pipes. The most prominent among these combustion products is carbon dioxide (CO_2), a clear, odorless gas. Levels of CO_2 in the Earth's atmosphere have been rising steadily since continuous measurements began in 1957 at Mauna Loa in Hawaii. This increase appears to be caused primarily by the human combustion of fossil fuels. Carbon dioxide absorbs infrared radiation and traps heat. Elevated concentrations of CO_2 are warming the atmosphere, which has disrupted the global climate.

Although this is a simple description of a complex phenomenon, it captures the essence of the link between fossil fuels and climate change. The effects that carbon dioxide levels in the atmosphere have on the climate are numerous and obvious. The physics of this are very well understood, and have been for centuries. The geological record shows clear examples of climate change in the past that correlate with changes in concentrations of carbon dioxide and other heat-trapping gases in the atmosphere. Despite the denials of "climate contrarians," the science is clear, the evidence is unequivocal, and the linkages are very apparent.

Human activities are adversely affecting the Earth in many ways. Global climate change resulting from fossil energy use is just one example. Human modifications to the landscape from timbering, agriculture, mining, and urban development have changed drainage and runoff patterns, affecting streamflow, groundwater recharge, and degraded both terrestrial and aquatic ecosystems. The over-use of groundwater resources has resulted in net aquifer drawdowns that exceed recharge. Runoff of chemical fertilizers from agricultural fields is dumping excessive plant nutrients into streams and waterways, leading to choking algal blooms and creating anoxic "dead zones" in bays and coastal oceans. Excess carbon dioxide dissolving into seawater has caused acidity levels in the oceans to rise, adversely affecting marine life, especially shelled creatures. Heavy pharmaceutical usage from prolific medical prescriptions and especially in livestock production has introduced drugs and endocrine disrupting chemicals widely in surface streams, leading to intersex fish,

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_9

antibiotic-resistant bacteria, and other problems. Higher water temperatures in the oceans result in more powerful hurricanes and damage to coral reefs.

Human history has been a relentless exploitation of the Earth, to “tame nature,” extract mineral resources, harvest timber, and turn just about everywhere into farmland. Resources seemed infinite. Almost no one worried about running out of bison to hunt on the American Great Plains, elephants to kill in Africa for their ivory, or whales to harpoon for oil and meat until these animals became scarce. Immense forests of old-growth timber were cut for ships, houses, and firewood, with only small, isolated stands remaining today. A few people like John Muir began raising alarms in the early twentieth century, pointing out that these resources were not limitless and should be conserved. Despite those who claim that human activities have no measurable effect on the climate, there is plenty of evidence to show that humans are more than capable of altering many Earth systems, including climate, often in a detrimental way.

The first widespread realization that humanity could adversely affect the climate on a global scale came about during the development of the first atomic weapons in 1945. Dr. J. Robert Oppenheimer’s famous quote from the Bhagavad-Gita after the successful Trinity test in New Mexico: “Now I am become death, the destroyer of worlds” is a legend of the nuclear age and sums up the civilization-ending potential of nuclear war. Military personnel, scientists, and most political leaders are under no illusions about the risks to the entire Earth that would come from the use of nuclear weapons. Indeed, this reality has been an important factor in pulling nuclear-armed nations back from the brink more than once.

The widespread realization among average citizens that nuclear weapons could inflict devastation on unimaginable scales is traced by historians to a NATO war game in 1955 known as “Carte Blanche” (Richardson 1966). This exercise imagined a European conflict lasting 6 days that was fought largely by rival air forces. Simulated NATO aircraft employed tactical nuclear weapons to counter slightly superior simulated Soviet forces. Of the 335 simulated nuclear missiles deployed against the Soviets, 268 of these landed on West Germany, killing 1.7 million simulated people. When the results of Carte Blanche were leaked to the press, the actual non-simulated people of West Germany were understandably alarmed, and protest movements began soon afterward to demand the removal of all nuclear weapons from Europe.

Dr. Carl Sagan at Cornell University and his colleagues took it a step further, and based upon their studies of planetary atmospheres, modeled the severe cooling of the Earth that would result from the massive quantities of soot injected high into the atmosphere from cities burning under nuclear fires (Turco et al. 1983). Sagan popularized the notion of a “nuclear winter” in the 1980s and called for reducing the number of nuclear weapons to levels below this threshold in an effort that he labeled as “planetary hygiene.” The idea of humans being able to actually change the fundamental properties of the Earth began to grow in public consciousness.

Along with the impacts that humanity has had on the environment, it is also important to recognize that the environment impacts humanity. Global warming and other manifestations of climate change are causing increasingly larger human populations to deal with stronger and more frequent storms, deadly heat waves, intense droughts, extended wildfire seasons, and rising sea levels. Other issues include a lack of clean drinking water for tens of millions of people, and respiratory distress and illness in large cities like Beijing or Mumbai because of air pollution. Groundwater supplies used for irrigating crops in the U.S. Midwest are being depleted. Even aquifers in the east, which receive ample rainfall for recharge, are still being depleted around population centers like Washington, D.C. because of overuse (Soeder et al. 2007).

Climate change is a critically-important issue affecting the environment of the Earth, but by the same token, it is not the only critical issue. It is important to not lose sight of the many other environmental challenges facing humanity and the world. However, climate change is overarching, and fixing the other challenges without addressing climate will sooner or later make all environmental improvements moot.

9.1 The Sixth Mass Extinction

Geologists divide the history of the Earth into a variety of time periods, based on rock types, localities, the distinctive plants and animals that were around, or the mass extinction events that have happened several times in Earth history (the demise of the dinosaurs being only one such example). The naming of individual time intervals has an interesting history beginning with James Hutton. Hutton was a physician, chemist, and farmer in eighteenth century Scotland who essentially invented the science of geology.

Based on religious scripture, most eighteenth century scholars considered the Earth to be around 6000 years old. In fact, after detailed analysis of the Bible, Archbishop James Ussher of Ireland announced in 1650 that the Earth had been created on the evening of October 22, 4004 B.C. His date was accepted for nearly two centuries.

Early geological naming schemes were based on biblical tales of Noah's Ark and the notion of a worldwide Great Flood. Thus, the original rocks that formed when the Earth was created were called "Primary." Sediments that were deposited after the creation of the Earth but before the Great Flood were called "Secondary." Sediments from the flood itself were deemed "Tertiary," and sediments deposited after the floodwaters receded were labeled "Quaternary." Fossils were thought to be the remains of animals that had perished in the flood. Despite the many changes and advances in geological science since then, the terms Tertiary and Quaternary are still used in the geologic time scale to this day, preserving a bit of this history.

The idea of a global flood event fell out of favor with eighteenth century scientists when no one could explain where all the water came from or where it went, and no real evidence of such a flood could be found in the geologic record. The melting continental ice sheets during the transition from the last ice age into the present interglacial period raised sea level by roughly 400 ft. (122 m) and may have been responsible for the flood story in the bible and similar tales in other ancient cultures. Ice dams impounded vast amounts of meltwater in glacial lakes, and the sudden failure of an ice dam would have released this water into the ocean in a rapid outburst called a "jökulhlaup." The channeled scablands of western Washington State are evidence of catastrophic jökulhlaups from a glacial lake located in present-day Idaho and Montana (Waitt 1984). These "meltwater pulses" would have raised sea levels by tens of meters, in some cases rather quickly (Fairbanks 1989). For people living in coastal settlements, the inundation would be seen as a world-wide flood. Such a disaster would have left a deep impression on human culture, and stories about the great flood would be passed down for millennia.

Dr. James Hutton realized from the evidence in the rocks that the Earth had to be much older than the 6000 years stated by "biblical creation," because the natural processes he was observing could not have produced the resulting geological features in this short of a time frame. His most famous example is an angular unconformity at a place called Siccar Point, located in Scotland along the North Sea coast south of Edinburgh where horizontal sedimentary rocks overlie older strata that are tilted at a sharp angle (Fig. 9.1).

In 1669, a scientist named Nicolaus Steno in Italy had developed the law of original horizontality, which states that sediments are deposited horizontally before

Fig. 9.1 The angular unconformity at Siccar Point that inspired James Hutton to calculate the age of the Earth. (Photographed in 2019 by Dr. Brennan Jordan, University of South Dakota; used with permission)

eventually becoming sedimentary rocks. Steno also observed that younger rock units are deposited on top of older rocks, in what is now known as the law of superposition.

Hutton reasoned that if the angled strata at Siccar Point were originally deposited as horizontal sediments, as required by Steno, then after the sediment turned to rock, the rocks received their upward tilt by a later episode of mountain building or some other geologic activity. According to the law of superposition, the horizontal sediments deposited on top of the angled strata had to be younger than the episode of tilting, before they too were turned to rock.

Hutton's breakthrough was in assuming that the geological processes he could observe around him such as sediment deposition and erosion had proceeded at similar rates in the past. Using these rates, Hutton did the calculations for how long it would take to create the angular unconformity at Siccar Point and came up with an age for the Earth of hundreds of millions of years. We now know that even this age was far too young, because data from radiometric age dating of the oldest terrestrial rocks, corroborated by the ages of slightly younger moon rocks indicate that the Earth formed about 4.6 billion years ago (4.6 Ga). Hutton's observations resulted in other scientists thinking about the geological time scale and expanding it.

The names of geologic time intervals have come from a variety of origins. Some, like the Devonian period, are named after places where rocks typical of the time period are found; in this case Devonshire, England. Other place names include the Mississippian, Pennsylvanian, Permian, and Jurassic periods, the latter two named after the Russian city of Perm and the Jura Mountains on the border of France and Switzerland. Several time periods are named after the dominant rock of the age. The Carboniferous is the name for a period in Earth's history when the landscape was dominated by carbon-rich coal swamps. The Cretaceous Period refers to chalk, a dominant rock type of that age. The name is derived from the Latin word cretus, which means "grown," because chalk is a collection of microscopic plant and animal shells. The White Cliffs of Dover in the U.K. are a famous Cretaceous chalk outcrop, and there are many others.

Geologic time periods are subdivided into epochs, and there tend to be more of these in recent periods because more details are decipherable. The Tertiary, for example, contains two geological periods, the Paleogene and Neogene, and these are subdivided into a number of epochs such as the Paleocene, Eocene, Oligocene, Miocene and Pliocene. The Quaternary is subdivided into the Pleistocene and Holocene epochs. Humans or at least hominids have been around since the beginning of the Pleistocene. The Pleistocene is the time of Ice Ages, and the Holocene began when the last ice sheets melted about 12,000 years ago. Many geoscientists now advocate that a new epoch be added after the Holocene to describe the influence of humans on planet Earth. The name for this is the Anthropocene.

The Greek word ánthrōpos (ἄνθρωπος), which means "human," is the root for terms like anthropology, anthropogenic, and Anthropocene. Human influence on the geology of the planet is widespread and obvious. People have cleared forests, built railroads, canals, highways, and cities, sculpted coastlines into harbors and waterfronts, drained wetlands, altered natural streamflow and sediment transport by damming rivers, and excavated, mined, drilled, and pumped minerals, oil, gas, and groundwater from vast tracts of land. We have changed the composition of the atmosphere, and altered the water chemistry in streams, lakes, underground aquifers, and even in the oceans. All of this is stressing the biosphere, changing ecosystems, and killing off plants and animals, including entire species.

An event commonly used to establish boundaries between geological periods is a mass extinction, defined as the loss of 75% or more of existing species (Webb 2013). There have been five great mass extinctions recorded in the fossil record of the Earth: (1) the Ordovician-Silurian, (2) the Devonian-Mississippian, (3) the Permian-Triassic, (4) the Triassic-Jurassic, and (5) the Cretaceous-Paleogene (also known as the Cretaceous-Tertiary or K-T in older texts; this one took out the dinosaurs). The current rate of species loss is so great that many biologists have declared that we have entered the sixth great extinction in Earth history (Kolbert 2014). Previous extinctions were caused by external events such as supervolcano eruptions or asteroid impacts. The extinction that is now underway is the only one in the history of the Earth where the actions of a single species (*Homo sapiens*) are wiping out other species.

Human activities so far have led to the extinction or endangerment of about half of the existing species on Earth. Many historical creatures like the aurochs, moa, passenger pigeon, and dodo are long gone. The future survival of other, notable threatened species such as the black rhino, blue whales, timber wolves, Bengal tigers, and polar bears may also be in doubt. Thousands of other less charismatic species like insects, plants, birds, shelled sea creatures, fish, and coral are also endangered, and many have quietly gone extinct with little fanfare. Despite the fantasy of technological resurrection of extinct species in movies like Jurassic Park (which bemuses most geologists because it was filled with Cretaceous dinosaurs) extinction is pretty much forever.

The presence of humans on Earth will be preserved in sediments of the Anthropocene Epoch by artifacts ranging from cuneiform tablets to nuclear submarine reactors. Millions of years from now, evidence of human civilization on Earth will be available for future intelligent beings to study and ponder in the rock layers. As promised by many an elementary school teacher, the bad behavior of humanity will be recorded on our "permanent record" in Planet Earth's geology until the end of time. The upper boundary of the Anthropocene Epoch will be marked by the end of the sixth mass extinction, which may very well include us. Some pundits have proposed that the next post-human geological period following the Anthropocene should be called "Weleftthescene" or "Weshouldhaveseen."

It is very likely that some forms of life will survive an Anthropocene mass extinction, and new species will evolve in the future. The Earth has been through extinctions as bad, or even worse than anything humans are capable of causing. Past extinctions were followed by new creatures evolving to gradually fill the ecological niches left vacant by those that came before. There is no reason to believe that a human-induced extinction, whether by way of resource depletion, climate change, air and water contamination, release of a virulent disease, or that old standby, all-out nuclear war, would be any different. Life always seems to make a comeback.

Humanity needs to re-examine our interactions with Planet Earth, not just because of the harm we are doing to the environment, but because of the harm the environment is doing to us. We are an integral part of the terrestrial ecosystem, and any damage we do to it, we do to ourselves. Bad air and poisoned water affect ecosystems, but they also affect us. We have to breathe, we have to drink, and we have to eat. The old idea that humans were masters of the Earth is wrong. We are merely tenants here like every other living creature, and not great tenants at that – we certainly haven't taken very good care of the place. If we keep it up, there will be a reckoning soon with the landlady, Mother Nature.

The main excuse being given for keeping things the way they are is jobs. Claims that coal mining, oil drilling, steel mills, and rustbelt manufacturing must be revived and expanded because people need these jobs for their livelihood is old thinking, and a sentimental pining away for some imagined good old days. Many of these jobs are as obsolete as elevator operators or railroad porters. A single worker with a front end loader can mine more coal in a day than dozens of old-style miners with picks and shovels. Modern factories using computer-controlled robots can build automobiles faster, cleaner, and far more efficiently than Henry Ford's giant Rouge River plant in Detroit at the height of Model T production in 1920, and with just a fraction of the work force. The old jobs are not coming back, but there are plenty of new jobs out there instead.

New thinking creates new industries, which lead to new jobs. Look at travel: 100 years ago, the fastest crossing of the Atlantic Ocean took 5 days on an ocean liner. People back then would be astounded to learn that we can do it now in 5 hours. Airplanes were still a dangerous novelty in 1920, Lindbergh wouldn't cross the Atlantic until 1927, and jet engines wouldn't be invented for another quarter century. No one had yet heard of a commercial airline pilot, a flight attendant, an air traffic controller, or a credit card customer service agent, all of which are part of a modern trans-Atlantic crossing. These are new careers that came from new industries. Undoubtedly, the development and deployment of new technologies to repair the planet will also create a host of jobs with new names that we've never heard of, and provide employment for numerous people.

Some ideas and recommendations for ways to address energy and climate change so the Earth can operate in a sustainable manner are presented in the last two chapters. However, for any of them to work, it will require citizen support, political will, a desire to change the status quo, and a willingness to re-think how things are done. The good news is that each and every issue threatening the environment, including climate change, CAN be fixed with the implementation of the right technology and policy. Most of these problems were caused by technology and policy in the first place, so it stands to reason that they can be addressed using the same tools.

The bad news is that we must get started on this soon, or risk joining the sixth mass extinction. A few scientists estimate that we have up to 1000 years to get everything in order. Many others are far more pessimistic, giving humanity a century at the outside, and more likely 50 years if we don't start taking action soon. Most of the experts agree that continuing business as usual with our current trends in energy, environmental degradation, and resource utilization will take us over the cliff before the end of the twenty-first century. Thus, on the geological time scale of the Earth, the Anthropocene Epoch might turn out to be really brief.

9.2 Climate Contrarians

Human-induced climate change through the combustion of fossil fuels is recognized as a serious environmental threat by nearly all scientists. Why then has it not been addressed? There are a number of reasons related to economic and technological inertia, but the people who deny that human activities are capable of affecting the climate are a significant barrier. People who deny the reality of climate change often self-identify as “climate contrarians,” and many project a romanticized image of themselves as fighting the establishment, standing up to the status quo, or acting as independent thinkers. Americans admire the underdog, and predictably cheer on any loner who pushes against the prevailing current and goes their own way, whether or not they turn out to be right in the end. This has been a successful plot in many books, movies, and television series, especially westerns. It is deeply ingrained in American culture, and exploited by those who know how appealing it can be.

The news media absolutely love anti-hero stories. One example is the lone engineer who argued that the O-rings on the space shuttle solid rocket boosters would not seal well in cold weather. The warnings went unheeded by NASA managers until the Challenger exploded, and the story received a huge play in the media afterward. This was a real-life instance of a plot device used in almost every fictional disaster movie, which inevitably start out with officials ignoring the dire warnings of a single renegade scientist.

In the case of climate, however, the contrarians are going up against some very robust science. Substantial data sets like those from the Mauna Loa atmospheric observatory in Hawaii (Fig. 9.2) clearly show that carbon dioxide levels in the atmosphere have been steadily rising at an increasingly steeper rate since measurements began in 1957. The sawtooth pattern in the figure is caused by the annual spring bloom and autumn die-off of vegetation in the Northern Hemisphere that takes up and releases CO_2, but the solid line up the middle is the trend. Alarmingly, if one lays a ruler or straightedge against this trend line, it can be seen to grow steeper over time.

Concentrations of atmospheric CO_2 have increased by about 100 parts per million (ppm) or around 30% over the last 50 years. This is carbon that has been added to the atmosphere in amounts greater than the natural “carbon cycle” can accommodate. The Earth regularly exchanges carbon between living plants, animals, the atmosphere, oceans, soil, and rock. The conversion of ancient plants into petroleum and coal is one method to remove CO_2 from the atmosphere and trap it deep underground. Combustion products from the burning of these fuels releases the CO_2 back into the atmosphere.

The increase in atmospheric concentrations over time shown in Fig. 9.2 suggests that the carbon cycle is out of balance. Natural CO_2 sources such as volcanic activity

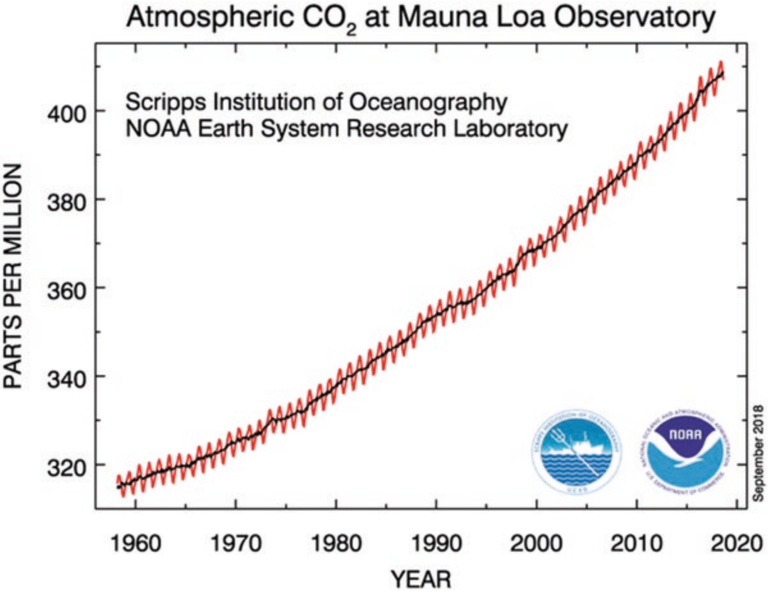


Fig. 9.2 Carbon dioxide levels in the atmosphere measured since 1957 at Mauna Loa in Hawaii. (Source National Oceanic and Atmospheric Administration (NOAA))

do not show any trends that can be related to the increase in atmospheric CO_2 concentration, but the Mauna Loa data do match up with the steady increase in the human use of fossil fuels. There are no other credible sources for the CO_2 concentrations measured in the Mauna Loa data, or in any of the additional robust data sets that back up the Mauna Loa observations. The straightforward and logical conclusion that presents itself is that there is a direct link between the human combustion of fossil fuels and the observed higher levels of CO_2 in the atmosphere. Although the Mauna Loa measurements only go back to 1957, human fossil-fuel use on a large scale really began during the Industrial Revolution. Many scientists think Mauna Loa has only captured the latest part of a long trend.

Carbon dioxide is one of the primary combustion products emitted by the burning of carbon-rich organic material. Not all CO_2 is the same, however. Plant-based biofuels like ethanol are considered renewables because the CO_2 they emit when burned was taken out of the atmosphere when the plant that made the ethanol was growing. Burning it just returns the CO_2 back into the carbon cycle. (The same goes for methane emissions from cattle, which are sourced from microbial action on consumed grass.) Fossil fuels, on the other hand, release carbon into the atmosphere that had been stored in the deep subsurface for millions of years. The combustion of fossil fuels by human civilization is adding this deep subsurface carbon into the atmosphere and steadily increasing the concentration of CO_2.

Well, so what? Many climate contrarians will agree that this CO_2 increase is real, but they argue that it doesn't make any difference to the climate. It does. Climate trends tend to occur over long time scales that are difficult for humans to perceive directly, but mathematical models and the geologic record both show definite climate effects when CO_2 concentrations reach or exceed current atmospheric levels.

In 1824, French physicist Joseph Fourier identified the heat-trapping properties of carbon dioxide during his investigations of atmospheric radiative heat transfer. Fourier discovered that the carbon dioxide molecule is transparent to short wavelengths of infrared (IR) radiation, but it blocks and absorbs the longer IR wavelengths. Eunice Foote, a physicist from Seneca Falls, New York submitted her paper: "Circumstances affecting the heat of the sun's rays," to the 1856 annual meeting of the American Association for the Advancement of Science. Foote had run some experiments with different gases in glass cylinders and discovered that the cylinder with CO_2 trapped more heat and stayed hot longer (McNeill 2016). Irish-English scientist John Tyndall expanded this investigation in 1859 with different gases like water vapor, carbon dioxide, ozone, and hydrocarbons. Tyndall thought that changes in atmospheric chemistry could have been responsible for the Ice Ages that were just being recognized in northern Europe and North America.

The Earth receives short-wave IR from the sun that penetrates the atmosphere and heats the surface of the planet. This phenomenon is familiar to anyone who has ever walked barefoot on the beach on a sunny summer day. The warm Earth then re-radiates this heat energy back into space as longer wavelengths of IR radiation. These longer wavelengths of IR are absorbed by CO_2 molecules in the air and warm the atmosphere (Pierrehumbert 2011). An obvious clue that the atmosphere is warmed by heat from the ground is the fact that the air gets colder with increasing altitude. This is why jet aircraft leave contrails and lofty mountain peaks have snow on them all year.

Fourier called this property the "hothouse effect" and determined that it was a primary mechanism for keeping the atmosphere warm. We now know it as the greenhouse effect (since the term "hothouse" went out of fashion in Victorian times), and carbon dioxide and other heat-trapping gases are called greenhouse gases or GHG. Greenhouse warming is important for keeping nighttime temperatures on the Earth from plummeting to far below freezing after sunset. Daily temperature swings on other planets with little or no greenhouse warming like Mars or the moon can vary by hundreds of degrees between day and night. On planets like Venus with extreme greenhouse warming, atmospheric temperatures are constantly scorching hot, and there is little temperature difference between the day and night sides.

Tyndall's hypothesis that changes in the concentration of atmospheric gases might have caused the Earth's ice ages led a Swedish physicist and chemist named Svante Arrhenius to construct and publish the first mathematical climate model showing the influence of atmospheric carbon dioxide on global temperatures (Arrhenius 1896). Professor Arrhenius was already well-known for formulating the theory of electrolytic dissociation (i.e. passing an electric current through water to break it down into hydrogen and oxygen), and he received the 1903 Nobel Prize for that work. The carbon dioxide paper contains a fairly concise and constrained mathematical model showing how atmospheric gas composition may influence the temperature of the Earth, and how variations in atmospheric CO_2 concentrations allow the Earth to warm or cool.

Despite Dr. Arrhenius' best efforts we now understand that the onset of the ice ages was caused by multiple factors, including the mechanics of the Earth's orbital cycles, changes in solar heat output, and variations in ocean currents, along with changing carbon dioxide levels in the atmosphere. The climate we are in at present is an interglacial period within a larger ice age that began approximately three million years ago (Ehlers and Gibbard 2011).

Although carbon dioxide levels in the atmosphere are not the sole cause of climate shifts, changing the concentration of the gas does have an effect on the heat budget of the Earth. One prominent source of CO_2 known even back in Arrhenius' day is fossil fuel combustion. He made an interesting calculation in his carbon dioxide paper showing that burning the annual global production of coal (around 500 million tons in 1896 at the time of the article) could be expected to increase CO_2 levels in the atmosphere by about one part per thousand every year. This is actually quite high, and the Earth would resemble Venus by now if the rate was real. Arrhenius overestimated atmospheric CO_2 concentrations by not accounting for substantial absorption by the oceans, incorporation into vegetation, and the increased chemical weathering of rocks. Based on the measurements shown in Fig. 9.2, the actual rate of CO_2 increase in the atmosphere is about 2 parts per million per year, some 500 times lower than that predicted by Arrhenius. As an interesting aside, coal production worldwide in 2013 was about 8701 million tons, or 7893 million metric tons according to the most recent EIA data, more than 17 times greater than in Arrhenius' day.

There are other GHGs in addition to carbon dioxide. Prominent among these is methane, the primary component of natural gas, and it is also generated by anaerobic biological processes. Methane is actually a stronger absorber of infrared radiation than CO_2, but it is easily oxidized and is relatively short-lived in the atmosphere. Other potent GHGs are the so-called ozone-depleting substances that include compounds such as chlorofluorocarbons (CFCs), widely used at one time as refrigerants (Polvani et al. 2020). CFCs were identified in the late 1970s as the cause for the dramatic deterioration of the ozone layer that protects the Earth from ultraviolet radiation. They were banned worldwide in 1987 with the adoption of an international agreement called the Montreal Protocol. CFC levels in the atmosphere have been slowly declining ever since, but with lifetimes of 52 years for CFC-11 and 102 years for CFC-12, it will take some time to clear them out (Solomon et al. 2014).

It is becoming increasingly obvious that human activities are affecting the chemistry of the atmosphere. The behavior of carbon dioxide as a GHG is well understood, even if its effects on the climate are complicated. The destruction of the ozone layer by CFCs and the contribution of these gases to a warming atmosphere are accepted as solid science. The ability of methane to trap heat is not in dispute. Sophisticated mathematical models far more complex than anything Professor Arrhenius could have imagined are predicting increased weather instability, warming of the polar regions, sea level rise, deadly heat waves, larger storms, and more intense droughts. These predictions have been verified by actual observations in recent years, and if anything, the climate models have underestimated both the rapidity of onset and the intensity of the effects. The Intergovernmental Panel on Climate Change (IPCC) has reported a near-total consensus among scientists that global climate change is underway, and that the processes underlying it are human-caused. Therefore, it is hard to fathom why climate skeptics even exist.

There are as many reasons as there are climate contrarians. Some people simply can't or won't try to understand the basic physics and chemistry involved. Others have a general distrust of science and scientists, and react to everything scientific with skepticism. Conspiracy theorists lump climate change in with other "conspiracies" like chem trails, fluoride in drinking water, the faked moon landing, and the flat Earth. A substantial number of wealthy people strive to maintain the status quo, and deny climate change because their comfortable lifestyles might have to alter to accommodate it. Some climate deniers are paid "researchers" for certain institutes and think tanks focused on influencing government policies to minimize all environmental concerns, including those related to the use of fossil fuels. A significant number of climate contrarians are committed to the continued growth of the fossil fuel industry, and deny climate change because it might affect their jobs or investments.

There are different ways of denying climate change. Professor Mark Maslin of University College London identifies "five pillars" of climate change denial (sourced from The Conversation UK under creative commons license; http://theconversation.com/the-five-corrupt-pillars-of-climate-change-denial-122893; accessed 11/30/19). These are described as follows:

1. **Science denial** challenges the accuracy of climate science, and claims that the issue is not "settled." According to 97% of the world's scientists, it is settled. Deniers question the accuracy of atmospheric carbon dioxide measurements. Some suggest that climate change is just part of a natural cycle. A few might agree that carbon dioxide levels are indeed rising, and even agree that the rise is caused by fossil fuel combustion, but then ignore the physics and suggest that CO_2 is such a small component of the atmosphere that it cannot possibly have a significant warming affect. A variation on this argument is that CO_2 levels are indeed rising and will affect the climate, but the increase in atmospheric CO_2 has nothing to do with fossil fuel use, even though no other sources are identified. Others attack the climate models as unreliable and too sensitive to carbon dioxide. Climate models predicting global temperature rise have remained consistent with the addition of new data over the last 30 years, indicating that the underlying science is quite robust.
2. **Economic denial** asserts that climate change is too expensive to fix. Some climate contrarians have argued that restricting fossil fuel use and requiring management of GHG would incur costs that are more disruptive to world economies than climate change itself (e.g. Adair 2012). When the actual numbers are put to this supposition, the cost of runaway climate change is much higher and far more unpredictable (The Economist 2019). Economic models suggest that the current cost of mitigating climate change would be about 1% of the

world GDP. The caveat is that the longer we wait, the worse it will be, and the more it will cost. If no action is taken, it could cost over 20% of world GDP to deal with the climate crisis by 2050. A substantial source of immediate funding to begin dealing with climate change could be a redirection of the annual government subsidies paid to the fossil fuel industry. These include supply costs, tax breaks, and environmental costs that by some calculations are currently equivalent to 6% of the world GDP (Coleman and Dietz 2019).

3. **Humanitarian denial** declares that, believe it or not, climate change is good for us. The argument is that a warming climate gives temperate zones longer summers that will make farming more productive. Higher levels of atmospheric carbon dioxide will also help to grow more robust plants. The downside, of course, is that higher temperatures also lead to increased droughts and heatwaves, like the one in 2010 that killed 11,000 people in Moscow and Eastern Europe, and devastated the Russian wheat harvest (Dole et al. 2011). Recent wildfire seasons driven by droughts in California and Australia have seen millions of acres burned. The climate models also predict more intense storms, which can damage agriculture, infrastructure, and risk lives. Forty percent of the world's population resides in tropical regions that already suffer from increasing desertification and public health crises. No one living in the tropics wants summer temperatures to rise. Climate change will also strongly affect the polar regions, melting permafrost and ice caps, raising sea levels by tens of meters, displacing millions of people from coastal areas, drowning some low-lying countries, and causing all sorts of other disruptions. Any "humanitarian" benefits of climate change that do exist will be offset many times over by the sheer amount of human misery it will cause.
4. **Political denial** is the argument that we cannot take action against climate because other countries are not taking action. As one of the major emitters of GHG, the United States should be leading the way on reducing emissions, not dodging responsibility because some tiny country in Africa also refuses to act. The U.S. along with China, Japan, and the European Union make up the developed economies that emit three quarters of the global GHG. India is not far behind from joining the club. These nations have an ethical responsibility to take action on the climate regardless of what the rest of the world does. If the goal is to get to zero net GHG emissions by 2050, ultimately all countries will have to act. However, it will happen a lot faster if the big players take action now rather than later.
5. **Crisis denial** defends the status quo by arguing that climate change might be a concern but it is not really a crisis as claimed by scientists. Rushing in to make changes would be rash and foolhardy. Similar arguments have been used in the past to delay the end of slavery, deny women the right to vote, maintain racial segregation, refuse to recognize worker's rights, and resist environmental regulations. Crisis denial appeals to those who do not inherently embrace change, but desire things to remain static and stable. Climate change suffers by not being an obvious crisis like a war or an epidemic. Crisis denial suggests that people will be forced to give up things like cheap electricity or large pickup trucks for no good reason.

Some who deny climate change do so out of loyalty to a team or a tribal mentality where believing something different from the rest of their group is considered a betrayal and almost treasonous. They often go along with their side without giving it much thought. This appears to be a manifestation of an ancient adaptation by humans in hunter-gatherer societies where a refusal to share community beliefs could result in an individual being shunned or outcast from the group, making the person much more vulnerable to the dangers of a savage world. One's very survival back then could depend upon being agreeable. Others deny climate change because of a phenomenon known as "motivated skepticism," where people tend to be more accepting of information that supports their existing set of beliefs, and skeptical of contradicting information. Depending on what one believes politically or religiously, accepting the reality of climate change may require a significant reassessment of core values.

Conspiracy theories arise from a different mental process where people think they see patterns and data in the world that don't actually exist. For example, the anti-vaxxer claim that vaccines may cause autism is based on a discredited paper published in the U.K. by Andrew Wakefield in 1998, which was subsequently retracted after the studies were deemed fraudulent and the data misrepresented. It no longer exists in the scientific record. However, some members of the public are continuing to cling to this idea despite extensive rebuttals by public health agencies and numerous scientific investigations that found no such links (i.e. Taylor et al. 2014). Conspiracy-oriented climate contrarians (and some fracking opponents) are often similarly stubborn, remaining convinced that any actual findings contrary to their beliefs must be faked or tainted and just act to further prove the conspiracy.

The conspiracy theory version of climate denial often ties it to a general suspicion of world governments, a distrust of so-called "deep state" official stories, and skepticism of anything that calls for worldwide solutions, like the Paris climate accord (Merlan 2019). Some of this suspicion can be traced back to a 1992 nonbinding environmental agreement passed by the United Nations called Agenda 21. It drew immediate opposition from American right-wing and anti-environmental groups, including conspiracy-based organizations like the John Birch Society who saw Agenda 21 as a U.N. plot to take away American independence (Merlan 2019). Virtually all global environmental issues since then, from ozone depletion to plastic in the oceans have been met with skepticism by these groups.

A conspiracy theory can act as a balm for people faced with a complicated problem like climate change because it resolves the issue by dismissing scientists, experts, and activists as the globalist tools of a Satanic Cabal (or some such) who can safely be ignored. The bottom line to true believers is that if climate change is only a conspiracy, then they shouldn't worry about it because absolutely nothing really needs to be done.

From a logical standpoint, climate denial requires a contrarian to believe that tens of thousands of scientists in more than a hundred countries are all in cahoots to carry out a massive fraud using fake data to show that climate is changing. When pressed, contrarians often claim the goal of these scientists is to scare citizens and receive more government grant funding. No one has come forth with any evidence or witnesses so far to expose this supposedly wide-ranging, nefarious plot. The logic of the contrarians leads to the unlikely conclusion that if not for a plucky band of billionaires, oil company executives, and well-funded politicians, the common people would be overrun by dangerous Green Energy schemes that seek to declare a war on coal, raise taxes, and put miners and drillers out of work.

To complicate the issue even further, there is an organized and well-funded opposition to climate change concerns. Robert Brulle at Drexel University in Philadelphia conducted an analysis in 2013 of the financial resources used to fund organizations and institutes he described as “the climate change counter-movement“or CCCM in the United States (Brulle 2014). The annual average funding from 140 different foundations for the 91 CCCM organizations identified by Brulle totaled $64 million. The money came overwhelmingly from conservative foundations, who generally attempted to conceal it through the use of donor-directed philanthropies. The CCCM-funded think tanks and institutes have been using tactics developed for the tobacco industry (by some of them, as a matter of fact) to create uncertainty and doubt in the minds of the American public about the reality and seriousness of climate change.

Senator Sheldon Whitehouse (D) of Rhode Island has called for the so-called anonymous “dark money” funding climate contrarians to be unmasked and stopped, saying it has “poisoned the U.S. political process” and blocked action on climate change (Showstack 2019). Senator Whitehouse indicated that when he arrived in the Senate in 2007, bipartisan efforts to address climate change were moving forward slowly but steadily. After the U.S. Supreme Court passed the *Citizens United* decision in 2010, which allowed corporations to provide essentially unlimited funding to political action committees (PACs), Congressional climate change efforts “fell apart” under a flood of fossil energy and conservative PAC money reaching Washington.

Efforts like the Green New Deal, introduced by Representative Alexandria Ocasio-Cortez (D-NY) and Senator Ed Markey (D-MA) early in 2019 contain many ideas for combating climate change. Some of these are good and others less so, but there has been little meaningful debate or movement on it because it is stalled in a reluctant and combative Congress. Nevertheless, the U.S. House Committee on Energy and Commerce has made 2050 the target date for reducing U.S. greenhouse gas emissions to zero. This aligns with similar zero-GHG emission target dates in France, Germany and Japan, and follows recommendations from a 2018 report by the IPCC to limit global warming in the twenty-first century to 1.5 °C (IPCC 2018).

Climate change has been called a “Chinese hoax” by some U.S. leaders, supposedly so China can get away with burning more cheap coal while forcing other countries to use low carbon energy or implement expensive carbon capture and storage programs. China is indeed the major emitter of carbon dioxide of any nation on the planet, but unlike the U.S., it has chosen to remain committed to the 2016 Paris Agreement to mitigate GHG emissions and adapt to climate change. China is also developing an active and robust carbon dioxide capture and storage program larger than the one in the United States.

The Chinese are rapidly shifting away from coal in any case toward much cleaner natural gas to improve the dismal air quality in their expanding cities. Natural gas emits only about half the carbon dioxide as coal per Btu of energy, so as almost a side effect to clearing the air this change will reduce China's GHG emissions substantially. China has been importing LNG because the nation's conventional natural gas resources are limited, and much of this is "sour gas" that contains corrosive and toxic hydrogen sulfide. The country does have potentially very large shale gas resources, and these are actively being developed (Soeder and Borglum 2019).

Other climate contrarians argue that the Earth's climate has changed naturally in the geologic past, and that any changes seen today are just part of a natural cycle. While climate does change naturally over geologic time, anthropogenic climate change is an abrupt and intense disruption superimposed on this natural signal. Climate on Earth has ranged from the tropical heat of the Carboniferous coal swamps to the frozen "snowball" Earth of the Cryogenian Period. Trying to make a case for "natural" climate change ignores the fact that human civilizations developed during a period of climate stability that began after the last glaciation and has lasted for about 10,000 years. This stable climate allowed for predictable seasons, established coastlines, the development of agriculture, and the construction of cities and civil institutions. Natural climate change happens slowly on human scales, over tens of thousands of years. The anthropogenic increase in GHG has taken place far more quickly than most changes to Earth systems. It is the impact of this rapid change on climate that is a cause of concern.

NASA has produced the graphic shown in Fig. 9.3 from the analysis of air bubbles trapped in Antarctic ice cores. The line reflects 400,000 years of changes in atmospheric carbon dioxide concentrations from different layers of snow incorporated into the Antarctic ice cap. For those who claim that the climate change we are now facing is a natural event, these data clearly show that none of the natural variations in CO_2 levels over the past half million years have been anywhere near as dramatic as those from 1950 onward. Since this image was published in 2013, carbon dioxide concentration has climbed by another 15 ppm. Every thinking person on Earth should find the graphic alarming.

Since the appearance of oxygen-emitting photosynthetic plants and the transformation of most of the carbon dioxide in the early atmosphere into carbonate rocks and fossil hydrocarbons, the Earth has developed natural feedback mechanisms to maintain more-or-less consistent levels of carbon dioxide in the atmosphere. Increased CO_2 from a volcanic eruption, for example, will be mitigated in a few thousand years by the increased weathering of basaltic rocks, which tie up the carbon as solid minerals, and by increased plant growth, which turn carbon into organic material. The problem with anthropogenic carbon dioxide from fossil fuel combustion is that we have emitted too much too quickly for the Earth to cope.

The most extreme climate change event in the relatively recent geological past was the Paleocene-Eocene Thermal Maximum or PETM, which occurred about 56 Ma (Jardine 2011). An abrupt increase in atmospheric GHG led to a global temperature rise of up to 8 °C. The origin of the GHG responsible for this event is

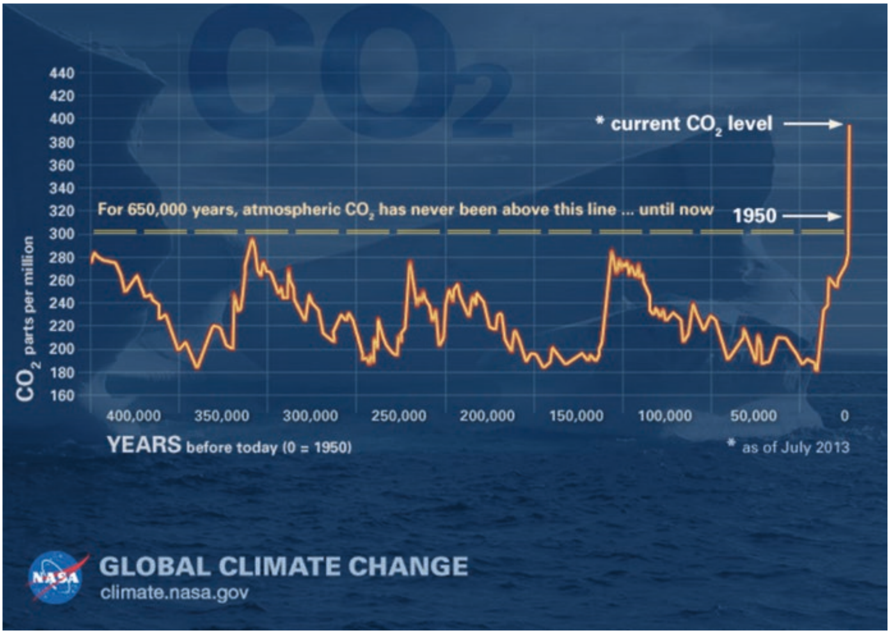


Fig. 9.3 Carbon dioxide concentration in the atmosphere over the past 400,000 years. (Source: NASA)

unclear, although it was possibly a combination of carbon dioxide from volcanic eruptions and methane released from sea floor sediments. Although "abrupt" in a geological sense, the rise in GHG concentrations that led to the PETM event took place over a time period of about 6000 years. The present-day, similar rise in atmospheric CO_2 from anthropogenic fossil fuel combustion has required just 200 years. Over the next few thousand years, the effects of human-induced climate change may become as intense as those of the PETM. After the onset of the PETM, the planet remained abnormally warm for 150,000 to 200,000 years, completely melting the polar ice caps, which did not get re-established until the Oligocene Epoch.

Some climate contrarians bring up predictions from the 1970s that the Earth was actually getting colder, and could even be headed toward another Ice Age. Those predictions were based on the amount of soot, smog, and sulfur aerosols that were being injected into the atmosphere at the time by the unconstrained burning of fossil fuels. The various combustion products reacted with ultraviolet light and water vapor to create clouds and hazes that blocked sunlight, cooling the Earth. However, these combustion products also had more immediate and severe health and environmental consequences that led to their fairly rapid mitigation.

A combustion product of high-sulfur coal is sulfur dioxide (SO_2), which reacts with water droplets (H_2O) in clouds and forms sulfuric acid (H_2SO_4). The resulting "acid rain" decimated aquatic life in lakes and streams of the eastern U.S. and caused noticeable damage to limestone and marble objects like historical grave markers, stone buildings, statues, and even concrete. Sulfur compounds also block sunlight. Photochemical smog from petroleum combustion created thick brown hazes over cities that also dimmed the sun. These caused a substantial rise in the number of “unhealthy air days” that led to all sorts of respiratory problems in urban populations. So, although the global cooling predictions of the 1970s were reasonable given what was known at the time, things have changed since then. Sulfur has been removed from coal smoke, and photochemical smog from automobiles has been greatly reduced by the introduction of catalytic converters, unleaded gasoline, and ethanol additives. Abundant sunlight is once again reaching the Earth, warming the planet.

Sulfur dioxide isn’t the only acid of concern. Carbon dioxide also creates carbonic acid when dissolved in water. The oceans have absorbed a significant amount of anthropogenic CO_2 emissions, and the levels of GHG in the atmosphere would be far higher without this. It has not been without consequence, however. The acidity of the oceans has increased by 30% over the past century, and many marine biologists and other scientists are alarmed at the consequences this is having on ocean life, especially shelled creatures. Animals build shells by removing calcium carbonate from seawater, but this requires neutral to slightly alkaline chemistry to achieve. The acidic oceans are dissolving away existing shells and preventing the formation of new ones (NOAA 2020).

Plant biochemists have linked the higher levels of carbon dioxide in the atmosphere to changes in the levels of sugar, starch and other carbohydrates in grass (Thompson et al. 2017). Warmer climate grasses are less affected than cool climate species, which have experienced nearly a 20% increase in the amount of fructan, starch, and sucrose in the plants compared to decades past. This is significant, and was accompanied by a decrease in total nitrogen in the leaves and changes in protein levels. This biochemical alteration has affected the nutritional value of these grasses for grazing animals, with consequences that are not yet known.

Suppose for a moment that 97% of the world’s scientists happen to be wrong and that climate change is actually a non-event. Doesn’t humanity still have a responsibility for controlling the emission of fossil fuel combustion products into the atmosphere? Can we just keep dumping these waste gases into the air and expect no consequences? Even if arguments about the physics of CO_2 warming the atmosphere are set aside, the acidification of the oceans and the changes in plant biochemistry are both measurable and alarming. In the end, what harm is done by ending these emissions? At worst, we’d have cleaner air. At best, we’d save ecosystems and possibly humanity itself. If the only reason behind climate denial is to maximize the profits of fossil fuel producers, that is a rather poor excuse to give to our great-grandchildren.

Climate contrarians need to provide a scientific justification for why they are so opposed to the reduction or elimination of CO_2 emissions and other fossil fuel combustion products into the Earth’s atmosphere. “Not believing” in climate change is not a valid argument. It doesn’t matter what someone believes. Science is based on evidence, not faith, and the evidence supports the reality of climate change. If climate deniers have any evidence to the contrary, they must publish it in peer-reviewed technical journals. Any credible scientific argument that purports to show climate change is a hoax must explain the following three points:

(1) Other than the human combustion of fossil fuels, what else can account for the dramatic increase in atmospheric carbon dioxide levels measured since 1957 at Mauna Loa?
(2) What evidence shows that Joseph Fourier's physics for the absorption of infrared radiation by CO_2 in the atmosphere are not valid?
(3) What evidence shows that the Earth will react differently than it did during the PETM as present-day GHG concentrations in the atmosphere approach those same levels?

Humanity is running an experiment with GHG and climate change, with no clear idea of how it might turn out. The IPCC gives a one in six chance that global temperatures will increase less than 2 °C in the next century and be lost in the natural background. There is also a one in six chance that global temperatures may rise by more than 9 °C and precipitate disasters like catastrophic sea level rise, intense storms, droughts, killer heat waves and all the rest predicted by climate models (IPCC 2018). The odds in Russian roulette are also one out of six. Do we really want to risk playing that with the Earth?

Children are having nightmares about climate disasters. Youth is rising up and demanding that something be done. People are marching and protesting about climate change on a regular basis. Energy and climate have become a part of national and international political discourses, and politicians who don't talk about it and don't have some kind of plan for dealing with it are criticized. Climate contrarians are trying to stop a large and growing wave.

Humans will have to adapt to climate change, because it is too late to avoid it. Even if all GHG emissions were stopped tomorrow, climate change is still going to happen. Just as shutting down the engines of large ship will not bring it to a halt until it has coasted for a considerable distance, the course for climate change has been set by past and present human actions for an unknown amount of time into the future. The effects on civilization are likely to be felt for centuries, possibly millennia. The best we can do is to try reducing the magnitude of the impact by getting GHG emissions under control and stop making things worse.

There will be both physical and transitional impacts from climate change. Physical impacts include elevated temperatures that may lead to deadly heat waves in the tropics and long stretches of above-freezing temperatures in polar regions. The heat will also melt sea ice, permafrost, and the polar ice caps on land areas like Greenland and Antarctica. Meltwater from this land ice pouring into the oceans will raise sea levels worldwide, potentially by as much as 250 feet (76 m) if all the ice melts (Poore et al. 2000). Coastal cities are at risk from sea level rise, and in fact, whole countries such as Bangladesh, Micronesia, and Holland might end up sinking beneath the waves like a modern-day Atlantis. Ocean currents may change, affecting local climates. Longer and more intense droughts are also more likely, along with stronger and less predictable storms. Agriculture and manufacturing will be affected, and areas of the planet that are considered "habitable" may need to be re-defined.

Transitional impacts of climate change are related to the human response. This may include things as mundane as switching vehicles from gasoline to electric, or changing electrical generating sources from fossil fuels to renewables like solar, wind, and geothermal or other non-carbon sources like nuclear. More substantial transitional impacts could include the large-scale migration of human populations to areas that are higher, drier, cooler, and provide more food and fresh water. Agriculture will transition to new crops for any particular region that are more heat tolerant, drought tolerant, cold tolerant, salt tolerant, or whatever else is needed to survive new weather patterns and temperatures. There could be wars over limited resources, or to defend national boundaries from migrating populations. (There have already been troop mobilizations among Egypt, Sudan and Ethiopia over serious disagreements concerning water allocations from the Nile River.) Large numbers of climate refugees could end up fleeing from newly-established deserts, places with intolerably hot temperatures, and drowned coastal areas.

It is interesting to note that climate change concerns have attracted the attention of the U.S. military. The Pentagon certainly takes climate change seriously and is not treating it as a hoax (Klare 2019). Military planners worry about sea level rise flooding coastal bases and naval ports, and these concerns have been amplified recently after a number of major facilities were significantly damaged by intense storms. In addition to infrastructure threats, the armed forces are also trying to prepare for some of the national security aspects of climate change, including wars and refugees. The concerns of the military have gained some traction with climate-denying members of Congress who may not care about the extinction of birds or bees, but definitely pay attention if there is a newfound potential for a horde of refugees to pour across the border.

Ignoring or denying climate change won't make it go away. The beauty of science is that it is based on facts, not beliefs. "Believing" in climate change is not required for the physics of Joseph Fourier, Eunice Foote, or John Tyndall to be valid. The calculations of Svante Arrhenius and the statistical conclusions reached by the IPCC stand on their own without the necessity of a leap of faith. Anyone who doesn't trust the physics or math may repeat the experiments and check the work. This is the way science operates. However, almost all scientists are confident in the results, and a large body of peer-reviewed literature has presented overwhelming evidence that human-induced climate change is underway. It is as inescapable as an avalanche coming down a mountain slope, which also by the way does not require the victims below to "believe" in gravity before it engulfs them. As Senator Whitehouse has said, "Time is not our friend with climate change." The longer we wait, the harder this is going to be to fix.

9.3 The Future of Fossil Fuel

Although the use of fossil fuels is sometimes labeled as "immoral" by environmentalists, there is no denying that fossil fuels have dramatically improved the overall living conditions for humanity, including health, hygiene, life expectancy and income (Epstein 2014). The difference in the quality of life between modern times and say, the Middle Ages, is largely due to the success of the Industrial Revolution, which would not have happened without fossil fuels.

The very existence of our modern civilization owes a lot to fossil fuel. Low-cost electricity from coal and natural gas, transportation across town or around the world in petroleum powered aircraft, automobiles, trains, and ships, and the replacement of dangerous town gas and coal in residences with non-toxic natural gas for water heaters, furnaces, and ovens have all made life more convenient and healthier for those with access to these resources. Fossil fuels were critical for the development of steel, aluminum, plastics, concrete, and other modern materials that have largely replaced traditional wood, leather, and stone. Fracking has opened up even greater reserves of oil and gas, making fossil fuels more abundant than ever.

All is not wine and roses, however. According to recent articles on OilPrice.com, the major oil companies are facing a host of problems ranging from low growth in oil demand, stagnant crude prices, and extremely low gas prices. Business models for big oil in the past were focused on continuous growth, with more spending and exploration to find new reserves and build larger production portfolios. This “drill, baby, drill” approach has worn thin with many investors, and companies are paying bigger stock dividends or buying back shares to stay afloat. ExxonMobil is about the only major company still pursuing the growth strategy.

During the coronavirus pandemic that swept the globe in early 2020, the oil and gas industry was one of the first to stand down, pull back and collapse. This predated the virus with a price war between Saudi Arabia and Russia to try to reduce the existing surplus of oil in the world, partly caused by aggressive U.S. shale production. Neither country could agree on acceptable quotas, and the oil glut was exacerbated when China cut petroleum and LNG imports as it began shutting down factories and keeping workers at home to limit the spread of the disease. This was followed by the shut-down of the global airline industry as people stopped traveling internationally, and then domestically, reducing jet fuel sales.

The stock market collapsed and factories in Europe and then North America began to shut down, reducing demand even further for energy and petrochemicals. Workers isolated at home in the U.S. from New York to California stopped driving except for necessities, using far less gasoline than normal and dropping gas prices to their lowest levels in decades. COVID-19 crashed oil demand by about 30 million barrels per day, and on an inflation-adjusted basis, oil reached its lowest price since the 1930s, including briefly touching $0 per barrel at one point. Pipeline companies told producers to cut back production and to not complete new wells.

Wall Street has grown increasingly reluctant to invest in fossil energy, and the collapse of oil prices did nothing to reassure hedge fund managers. Many investment companies and mutual funds are acquiescing to shareholder demands to divest from fossil energy stocks, and this is reflected in the price declines for energy shares. Divestment in the past has been driven largely by environmental concerns, but many of the issues now are strictly financial.

Oil companies have never been popular with environmentalists, and with climate change concerns now driving many protests, calls to halt offshore drilling and ban fracking are becoming more frequent. Proposed oil and gas pipelines routinely receive fierce opposition no matter how they are routed, and especially if they are designated for exports. Anti-petroleum sentiment and opposition to gas pipelines has grown so strong in Canada that Encana Corporation, an oil company headquartered for many decades in Calgary, Alberta, changed its name to Ovintiv, Inc. and moved operations to the more "business friendly" environment of Denver, Colorado as of January 2020.

Coal companies have also done poorly over the past decade, and several have gone bankrupt. Electricity generation, the main market for coal in the U.S. has been largely supplanted by natural gas and to some extent by renewables. Steel manufacturing, the other market for coal has also been usurped by natural gas. Demand for coal has dropped to historic lows. The so called "war on coal" narrative promoted by the mining industry to cast themselves as the victims of overly-zealous environmental regulations actually has little to do with the EPA, and a great deal to do with competition from cleaner, cheaper, abundant, and easier-to-handle natural gas from fracked shale. As might be expected, the coal industry is very strongly opposed to fracking, but not for reasons that would appeal to most environmentalists.

The short answer to "what is the future of fossil fuel" is that these troubles are but the tip of the iceberg. Oil and gas are plagued by overproduction, surplus inventories, low prices and reduction in demand. Cheap prices are the only thing that keeps them popular. Production is not resilient and easily disrupted by economics, weather, politics, and now also by pandemics.

Neither oil nor gas has made significant efforts in decades to find new markets. The replacement of coal for electrical generation by natural gas in the U.S. was almost accidental. The power companies discovered that once fracking had made it both abundant and cheap, gas gave them greater efficiency than coal at a lower cost. It certainly wasn't due to aggressive marketing by the gas companies.

On a fundamental level, oil, gas, and coal are non-renewable, non-sustainable resources that will run out eventually, perhaps in decades, certainly in a few centuries. The production and use of fossil fuel cannot continue indefinitely. An energy transition is coming one way or another. Knowing that fossil fuel has a limited future, wise government policy decisions made now could direct and encourage a smooth transition toward cleaner, more environmentally-friendly, and sustainable sources of energy. If business as usual continues unabated, however, the end of fossil fuel use will eventually be forced upon us very abruptly by the realities of geology and physics. Switching to new energy resources under these conditions is likely to be disruptive, poorly-planned and possibly not very smart.

The transition to sustainable energy is struggling at the moment because fossil fuel is just too cheap. A lot of this was due to the success of the fossil fuel revolution, where fracking allowed huge reserves of natural gas to be recovered from shale and overloaded the market (Soeder and Borglum 2019). Petroleum from tight oil resources is also overly abundant and has depressed prices. The cost of coal, on the other hand, is low not because of a supply surplus, but because abundant natural gas from shale caused already limited demand to fall sharply.

A former director of the DOE National Energy Technology Laboratory liked to note that a truckload of topsoil cost more than a truckload of coal, making the point that fossil fuel is literally cheaper than dirt. And the least expensive way to utilize the already cheap fossil fuel is to simply burn it in air and allow the combustion products to waft away into the atmosphere up a smokestack or out an exhaust pipe. These low-cost economics undercut all of the other, cleaner energy alternatives that are out there.

Fossil fuel would be far more expensive if the true cost of environmental damage and the risks to climate, air, water, landscapes, and public health were included in the price. They are not of course, and these are known as "externalized costs." Many industries employ this tactic of cost-shifting; for example, big tobacco transfers the cost of medical conditions that result from the use of their products to society; the burden in particular falls on the premiums paid by the non-smoking participants of group medical insurance plans to cover the cost of treatment for members with smoking-related illnesses. However, the energy industry and especially big coal are the undisputed champions of externalized costs. Society and taxpayers cover expenses for stream restoration, landscape reclamation, spill and environmental cleanup programs, and now climate disruptions and resilience. Placing the burden for these costs back onto the price of fossil fuel would help other, non-GHG emitting forms of energy become more economically competitive. Externalized costs are discussed in more detail in Chap. 11.

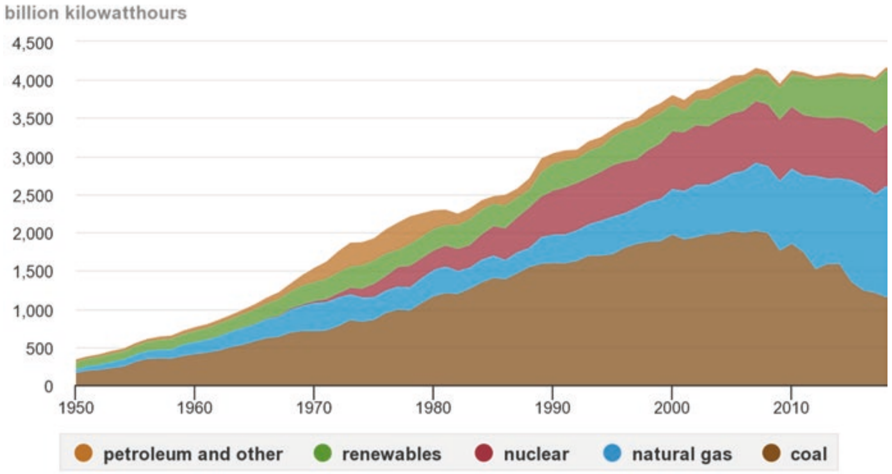
Several types of sustainable clean energy technology exist, but they are all more expensive than the equivalent energy from fossil fuel. Although many people claim to support a cleaner environment and profess concern about climate change, the bottom line is that if electricity from a clean, sustainable source costs them more money, most utility customers would rather pay a cheaper electric bill from a coal-fired generator. This is the carbon conundrum.

Competition from low-priced fossil fuel has forced renewable energy sources like wind turbines and solar installations to require tax incentives (another externalized cost) to survive as an alternative. If the United States ever hopes to transition away from fossil fuel to sustainable, clean energy through the "Green New Deal" or any similar policy, the economic playing field must be leveled and these cost differences addressed. Under the current rules of the game, fossil fuel prices undercut every available alternative, and our dependence on these fuels will likely continue for a long time to come if nothing changes.

A good way to compare the economics of different energy sources is through the cost of electricity. Electricity cannot make new power, but only transform a "primary" power source into another that is more easily transmitted and used. The amount of power generated in the U.S. varies, but to pick a number for an example, total U.S. electrical generating capacity in August 2019 was approximately 400 gigawatts (Gw). Fossil fuel generated 273 Gw or 68% of this total. The fossil fuels used for making electricity are primarily coal and natural gas. Abundant gas from fracking and the development of shales has in fact displaced coal over the past decade as the leading fossil fuel for electrical generation. Oil-fired electricity was more common in the U.S. before the 1973–74 energy crisis, but this was sharply curtailed after the crisis to keep liquid petroleum stocks available for transportation use. Oil use for electricity dropped further after 2010 when natural gas became abundant from fracking (Fig. 9.4).

According to data from the U.S. Energy Information Administration (EIA), nearly all non-GHG emitting sources of energy are presently more expensive per kilowatt-hour than fossil fuel-fired electricity (USEIA 2018). Geothermal electricity is cost-competitive, but in very limited use with present-day technology. Some ideas for expanding the use of geothermal are discussed in Chap. 12. Wind and solar are only able to compete economically with fossil fuel through tax incentives, and these renewables currently produce 9% of U.S. power. Hydropower from existing dams represents another 5% of U.S. power that could be considered a non-GHG "renewable." However, all the major rivers that can be dammed for hydropower have been dammed, and in fact, some of these dams are being removed. Nuclear power plants produce about 18% of U.S. electricity with no GHG emissions, but current nuclear technology is complicated, heavily regulated, and very expensive. (Some ideas for new nuclear technology are also explored in Chap. 12.) Nuclear power was an enormous capital expense for the utility companies, and once constructed, the reactors had to keep operating for many decades to pay back the investment. No new nuclear power plants have been licensed in the United States since the 1980s (source: EIA websites).

A number of political figures and environmental advocates have been talking about replacing fossil fuel-generated electricity with renewables. This is much larger than many people realize, and it would require a substantial investment in renewables to generate the equivalent of 273 Gw of electricity presently derived from fossil fuels. If this is done using currently-available renewable technology,



Note: Electricity generation from utility-scale facilities.
Source: U.S. Energy Information Administration, *Monthly Energy Review*, Table 7.2a, March 2019

Fig. 9.4 Primary energy sources used to generate utility-scale electricity in the United States. (Source: Energy Information Administration) wind and/or solar electricity making up the "renewables" section of Fig. 9.4 would have to be expanded to cover the power generated by coal and natural gas (oil is negligible and can be ignored). Renewables like wind and solar have a low energy density. This means that unlike energy-dense power plants that use natural gas, coal, or nuclear and essentially fit into a single building, renewables are spread out over long distances across the landscape. Anyone who has driven past the wind farms in Iowa or Texas can attest to their large size.

The math is formidable. The generating capacity of the average onshore wind turbine is about a million watts (one megawatt, or Mw). One gigawatt (Gw) is a billion watts, or a thousand Mw, requiring a thousand average wind turbines to replace one Gw of fossil. To replace all 237 Gw of fossil electricity, a total of 273,000 average wind turbines are required. At present, there are about 54,000 wind turbines operating in 41 states in the U.S. Four times as many would be needed to completely replace fossil fuel with wind.

Perhaps a larger wind turbine would help. The highest-output onshore wind turbines in the United States are in Texas, with capacities of around four Mw each. Using these for the sake of argument, about 68,250 of the four Mw wind turbines would be needed to generate 273 Gw of electricity. If these wind turbines were spaced 300 m (1000 ft) apart, their linear extent would be 20,475 km (12,000 mi).

Solar has a similar issue. The largest solar plant in the United States is the $2.2 billion (including a $1.6 billion loan guarantee from DOE) Ivanpah Solar Power Facility in the California desert, completed in 2014 and capable of generating 392 Mw of electricity (Fig. 9.5). It consists of three tall solar thermal towers heated by sunlight reflected from some 300,000 mirrors, and covers a land area in Ivanpah Dry Lake of approximately 3,500 acres, or 14.2 km^2 (source: http://www.brightsourceenergy.com/ivanpah-solar-project accessed 1/20/20). There is also a natural gas backup to supply additional heat if needed.

To generate the equivalent of 273 Gw of fossil fuel electricity, almost 700 more solar plants just like Ivanpah would be required. At around $2 billion each, the total cost would be about $1.4 trillion. If each power plant covered a similar amount of land area, almost 10,000 square kilometers or about 4000 square miles would be needed. This is somewhat smaller than the land area of Connecticut. This is not to say that either of these projects cannot be done, but many people speak glibly about replacing fossil with wind or solar without understanding the cost or the magnitude of the undertaking.

Photovoltaics have come down in price and are more efficient at producing electricity than solar thermal, but a 100 watt solar panel still costs around $150. To generate 273 Gw, it would require 2.73 billion of these 100 W panels at a cost of $409.5 billion (although there would probably be a volume discount). Each panel covers a surface area of 54 x 40 inches or 15 square feet (137 cm × 102 cm or 1.39 m^2). Laying out 2.73 billion of these panels would occupy a land surface area of about 1470 square miles, which is slightly larger than the state of Rhode Island.

Another major cost involved is related to the fact that both wind and solar generate electricity differently than fossil fuel plants. Natural gas and coal-fired power plants are called "thermoelectric" in that they use heat to boil water to make

Fig. 9.5 Solar power towers surrounded by mirrors at Ivanpah Dry Lake, California. (Photo: U.S. Department of Energy)

steam that turns a turbine. Replacing these with renewables would require utility companies to abandon millions of dollars' worth of existing thermoelectric generating infrastructure, while simultaneously spending huge sums of capital to build new wind and solar farms to make up for that lost capacity. There are not too many shareholders that would agree to this.

The main technical issue with wind and solar is that they generate energy intermittently. Wind turbines need a windy day. Solar doesn't work at night. Until energy storage devices are developed that can provide continuous power, renewables cannot be used for baseload electricity, only for peak shaving. Some lithium battery designs are showing promise for large-scale energy storage. One of the design considerations in the solar thermal plant at Ivanpah was a provision to store heat so the plant could continue to operate after sunset.

These examples illustrate some of the difficulties with just "doing away" with fossil energy. It will indeed need to be replaced eventually with more sustainable energy sources in the future. However, the approach has to be carefully thought-out, and cannot just be a simple call to action or a slogan. Some political leadership is needed to come up with a workable plan, help fund the development of new, advanced energy technology, and provide incentives and penalties to get utility companies to cooperate. Options for technology that can directly replace gas or coal in existing power plants without producing GHG are discussed in Chap. 12.

So how does the future of fossil fuel translate to the energy needs of the developing world? Many people in third-world countries aspire to live like populations in the industrialized world. Under-developed countries rightfully want heat, light, refrigeration, transportation, communication and the other benefits brought by fossil fuel and electricity. Shale gas is available in many places around the world, and nations from South Africa to Pakistan are considering their options for developing it, including fracking (Soeder and Borglum 2019).

Believe it or not, there are still one billion people in the world without electricity. Many parts of the planet simply have no electrical infrastructure in place – no generators, transmission lines or power distribution systems. An additional three billion people (over 40% of the world's population) still rely on unhealthy fuels like wood or coal stoves for heating and cooking. One of the "Sustainable Development Program" goals of the United Nations (Goal 7) is to provide "affordable and clean energy" to everyone in the world by the year 2030 (source: UN websites and reports).

How can this be done? Fossil fuel is still the energy resource of choice in developing nations (Brown 2019). It is cheap, the technology is well-understood and reliable, and it is often available in-country, or easily imported. To be sure, solar and wind are making inroads in remote, rural areas where simple solar-battery systems can be used for low-power LED lighting in huts and houses. Solar power can also supply chargers for mobile phones in villages where new communication systems are skipping the telephone wire phase and going directly to cell service. However, these low-power systems are of little use for heavy industries where the usual question for renewables is "how do you make steel?" Industrializing nations like China and India are substantially expanding domestic electrical capacity, where the primary energy source for producing large quantities of industrial power so far has been coal.

China and India are also developing robust economies and large middle classes that want access to consumer technology and goods. Many people in these countries aspire to live like Americans, but the math is dismal. With approximately 5% of the world population, the United States uses nearly a quarter of the world's energy supply. Trying to supply everyone in the world with the energy and materials needed to live a Western lifestyle using current extraction, generation, and manufacturing methods will exceed the capacity of the planet. In fact, it may very well exceed the capacity of several planets and is obviously not sustainable. But then how is it right and fair for the nations that industrialized first to take possession of all the available resources and leave nothing for the rest of the world? Other solutions are clearly needed and some substantial engineering problems must be solved.

Pleas by environmentalists in western nations for developing countries to forgo GHG-emitting fossil fuels in favor of renewables like solar or wind as they electrify are often met with derision. Any GHG emissions that might come from a third-world fossil-fuel power plant are a drop in the bucket compared to the developed nations. Cheap, abundant fossil fuels allowed the economies of Western Europe, North America, and eastern Asia to industrialize in the last century or two, leading to substantial wealth and higher standards of living. Many people in underdeveloped nations point out that it is easy for western environmentalists to relax in their comfortable, warm, and well-lit houses and demand that the third world adopt renewables to light their thatched huts. There is a risk that urging developing countries to use more expensive and less reliable renewable power will be seen as an attempt to deny them the opportunity to attain the same level of economic achievement, industrialization, and wealth as western nations. This is a sensitive subject in many parts of the third world.

Finally, people in developing nations bristle at the idea that they should be designated as the planetary leaders for reducing GHG emissions by being forced to use renewables. The damage that has already been done to the climate can be laid squarely at the feet of the United States, China, Japan, Russia, and the European Union. Emissions from India are climbing and will soon surpass those of the EU. The third world argues, with significant justification, that the major GHG-emitting nations should be the ones leading the way on reducing emissions and battling climate change. Undeveloped countries didn't cause the majority of the problem, and they contend that they should not be expected to fix it. It only takes a quick glance at GHG emissions by nation (Fig. 9.6) to understand their point.

Nearly 200 countries signed on to the Kyoto Protocols in 2005 and pledged to reduce greenhouse gas emissions. Since then, global GHG emissions have continued to creep upward, with significant increases in the Asia Pacific region and modest declines in the United States and Europe (BP p.l.c. 2019). The U.S. declines were driven by the replacement of coal with natural gas, while the European declines were primarily due to renewables. Essentially the same 200 nations signed on to the Paris Climate Accord in 2015. Since then, the pattern has continued with modest declines in some regions and substantial increases in others. Using modest declines to offset substantial increases runs into a major problem: we all share the same atmosphere.

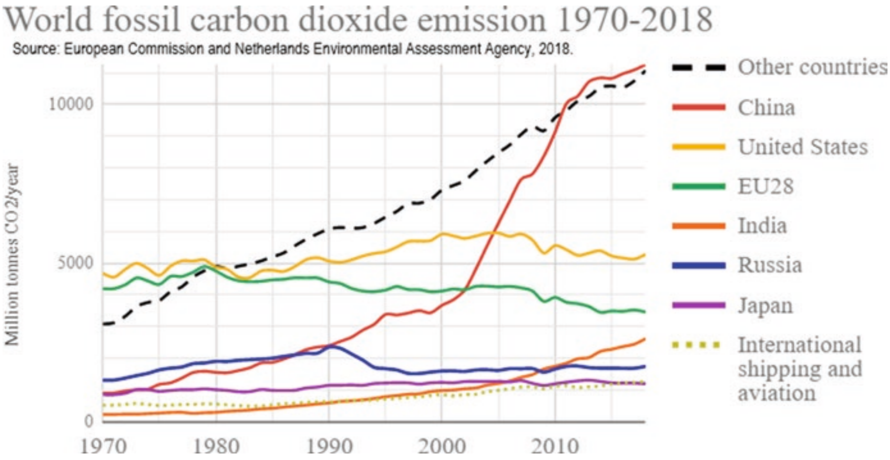


Fig. 9.6 Global carbon dioxide emissions by nation 1970–2018. (Source: European Commission and Netherlands Environmental Assessment Agency)

The top six emitters in 2018 are listed below with emissions in millions of tons of carbon dioxide, along with the percent change in emissions between 2007 and 2017: China: 9429 (+2.5%), United States: 5145 (−1.5%), European Union: 4248 (−1.5%), India: 2479 (+5.4%), Japan: 1148 (−0.8%), and Russia: 1550 (−0.3%) (BP p.l.c. 2019). Clearly, the world must improve on these numbers if there is to be any hope of managing climate change.

The future of fossil fuel is almost certainly going to require that the carbon dioxide gas produced as a combustion product be kept out of the atmosphere. There are two options for doing this: (1) use less fossil fuel in the first place and substitute non-GHG sources of energy for it as much as possible, and (2) for the fossil fuel that is being used, capture the combustion products and store them underground or in some other form to keep the GHG from entering the atmosphere. Both of these will help reduce GHG, but both will also result in higher costs.

So-called "carbon capture and storage" technology or CCS can be used to capture the CO_2 from fossil fuel combustion and place it deep underground instead of allowing it to escape into the atmosphere. The U.S. Department of Energy has been working on this for many years (e.g. USDOE 2012) to develop methods for capturing the emissions and assessing subsurface storage options for carbon dioxide. Because the implementation of CCS would raise the price of coal-fired electricity, research is also focused on finding uses for the captured CO_2 to help offset the costs and improve the economics. This is called carbon capture, use and storage or CCUS, and both acronyms are used in various DOE publications on the subject. Turning carbon dioxide from a waste product into a valuable commodity is arguably one of the most challenging aspects of the program. Ironically, the most common industrial use for captured CO_2 at present is to inject it into old oil fields to re-pressurize the reservoir and recover additional amounts of fossil fuel petroleum.

Although CCS would increase the cost of coal-fired electricity, it would still be within the price range of many other sources of electricity, including renewables and nuclear (USEIA 2018). In addition, by making coal-generated electricity more expensive, the implementation of CCS would improve the cost-competitiveness of renewables and nuclear, possibly expanding their percentage of the U.S. energy grid, reducing national GHG emissions. CCS could also be required on gasoline and diesel vehicles. This would increase their cost as well, but perhaps it would provide incentives for the development of advanced electric systems, compressed or liquefied natural gas, or even hydrogen fuel cells to power vehicles. If CCS was required on all fossil fuel combustion to prevent the emissions of GHG, the future of fossil fuels might be a little bit brighter. There is still a finite supply, but as society transitions to cleaner, more sustainable forms of energy, eliminating GHG emissions from the fossil fuels that remain to be burned will improve their acceptability.

Climate contrarians of course argue against the implementation of CCS because they claim it is unnecessary. The more important, underlying reason for their concern is that it will raise the cost of fossil fuels. The energy companies can be expected to simply pass this price increase along to consumers, so it is doubtful that it will affect their bottom lines directly. However, if fossil fuels become more expensive, people will conserve more and use less. More expensive fossil fuels will also make renewables and nuclear energy more cost-competitive and encourage their greater use, further reducing demands for fossil energy. So even if the profit margins for energy companies remain more-or-less constant, the volumes of natural gas, petroleum, and coal being sold could drop significantly. The reasons for climate change denial by the fossil fuel industry and its allies now become more apparent. As a wise man once said, "Follow the money."

References

Adair, R. K. (2012). Another exchange on climate change. *Physics Today. Readers Forum, 65*(3), 8.

Arrhenius, S. (1896). On the influence of carbonic acid in the air upon the temperature of the ground. *Philosophical Magazine and Journal of Science (London, Edinburgh, and Dublin), Series 5, 41*(251), 237–276.

BP p.l.c. (2019). *BP statistical review of world energy* (68th ed.). London: 64 p.

Brown, D. (2019, November). Hydrocarbons expected to remain the world's primary energy source. *AAPG Explorer, 40*(11), 6.

Brulle, R. J. (2014). Institutionalizing delay: Foundation funding and the creation of U.S. climate change counter-movement organizations. *Climatic Change, 122*(4), 681–694.

Coleman, C., & Dietz, E. (2019). *Fossil fuel subsidies: A closer look at tax breaks and societal costs: Fact sheet*. Washington, DC: Environmental and Energy Study Institute. 10 p. (https://www.eesi.org/files/FactSheet_Fossil_Fuel_Subsidies_0719.pdf).

Dole, R., Hoerling, M., Perlwitz, J., Eischeid, J., Pegion, P., Zhang, T., Quan, X.-W., Xu, T., & Murray, D. (2011). Was there a basis for anticipating the 2010 Russian heat wave? *Geophysical Research Letters, 38*(6), L06702. 5 p.

Ehlers, J., & Gibbard, P. (2011). Quaternary glaciation. In V. P. Singh, P. Singh, & U. K. Haritashya (Eds.), *Encyclopedia of snow, ice and glaciers* (Encyclopedia of earth sciences series). Dordrecht: Springer. https://doi.org/10.1007/978-90-481-2642-2.

Epstein, A. (2014). *The moral case for fossil fuels*. New York: Penguin Group. 256 p.

Fairbanks, R. G. (1989). 17,000-year glacio-eustatic sea level record: Influence of glacial melting rates on the younger Dryas event and deep-ocean circulation. *Nature, 342*, 637–642.

IPCC. (2018). *Global warming of 1.5°C: An intergovernmental panel on climate change special report (Summary for policymakers)*. Geneva, Switzerland, World Meteorological Organization, 32 p. (ISBN 978-92-9169-151-7).

Jardine, P. (2011). The Paleocene-Eocene thermal maximum. *Palaeontology Online, 1*, 1–7. Article 5.

Klare, M. T. (2019). *All hell breaking loose: The Pentagon's perspective on climate change*. New York: Henry Holt and Company. 304 p. (ISBN: 9781627792486).

Kolbert, E. (2014). *The sixth extinction: An unnatural history*. New York: Henry Holt and Company. 319 p. (ISBN 978-0-8050-9299-8).

McNeill, L. (2016). This lady scientist defined the Greenhouse Effect but didn't get the credit: *Smithsonian Magazine*, December 5, 2016. https://www.smithsonianmag.com/science-nature/lady-scientist-helped-revolutionize-climate-science-didnt-get-credit-180961291/

Merlan, A. (2019). *Republic of lies: American conspiracy theorists and their surprising rise to power*. New York: Metropolitan Books, Henry Holt and Co.. 288 p. (ISBN: 9781250159052).

NOAA. (2020). *What is ocean acidification?* National Ocean Service website. https://www.pmel.noaa.gov/co2/story/What+is+Ocean+Acidification%3F. Accessed 13 Jan 2020.

Pierrehumbert, R. T. (2011, January). Infrared radiation and planetary temperature. *Physics Today, 64*(1), 33–38.

Polvani, L. M., Previdi, M., England, M. R., Chiodo, G., & Smith, K. L. (2020). Substantial twentieth-century Arctic warming caused by ozone-depleting substances. *Nature Climate Change, 10*, 130–133. https://www.nature.com/articles/s41558-019-0677-4.

Poore, R. Z., Williams, R. S., Jr., & Tracey, C. (2000). *Sea level and climate*. Reston, VA: U.S. Geological Survey Fact Sheet 002–00. 2 p.

Richardson, J. L. (1966). *Germany and the Atlantic alliance: The interaction of strategy and politics*. Cambridge, MA: Harvard University Press. 403 p.

Showstack, R. (2019). Senator urges ending dark money's stifling of climate action. *EOS Earth & Space Science News, 100*(8), 7–8.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

Soeder, D. J., Raffensperger, J. P., & Nardi, M. R. (2007). *Effects of withdrawals on groundwater levels in Southern Maryland and adjacent Eastern Shore, 1980-2005*. USGS Scientific Investigations Report 2007-5249, October, 2007.

Solomon, S., Douglass, A. R., & Newman, P. A. (2014). The Antarctic ozone hole: An update. *Physics Today, 67*(7), 42–48. https://doi.org/10.1063/PT.3.2449.

Taylor, L. E., Swerdfeger, A. L., & Eslick, G. D. (2014). Vaccines are not associated with autism: An evidence-based meta-analysis of case-control and cohort studies. *Vaccine, 32*(29), 3623–3629.

The Economist. (2019, Feb 9). Crude Awakening: ExxonMobil and the oil industry are making a bet that could end up wrecking the climate. *The Economist, 430*(9129), 9.

Thompson, M., Gamage, D., Hirotsu, N., Martin, A., & Seneweera, S. (2017). Effects of elevated carbon dioxide on photosynthesis and carbon partitioning: A perspective on root sugar sensing and hormonal crosstalk. *Frontiers in Physiology, 8*, 578.

Turco, R. P., Toon, O. B., Pollack, J. B., Ackerman, T. P., & Sagan, C. (1983, December). Nuclear winter: Global consequences of multiple nuclear explosions. *Science, 222*(4630), 1283–1292.

USDOE (U.S. Department of Energy). (2012). *The United States carbon utilization and storage atlas* (4th ed.). Washington, DC: DOE Office of Fossil Energy. 129 p.

USEIA (U.S. Energy Information Administration). (2018). Levelized cost and Levelized avoided cost of new generation resources, *Annual Energy Outlook*, 20 p.

Waitt, R. B., Jr. (1984). Periodic jökulhlaups from Pleistocene Glacial Lake Missoula – New evidence from varved sediment in northern Idaho and Washington. *Quaternary Research, 22*, 46–58.

Webb, S. (2013). *Corridors to extinction and the Australian megafauna*. Amsterdam: Elsevier. 308 p.

Chapter 10
Mitigation and Remediation

Environmental professionals use two broad approaches known as mitigation and remediation to address environmental problems. Mitigation means changing the way something is done in order to reduce or prevent additional environmental damage. It can include things like installing sediment traps to protect waterways from construction site runoff for example, or using electrostatic precipitators on smokestacks to keep coal combustion fly ash from coating the countryside. Mitigation is the “prevention” step. Remediation, on the other hand, involves going back and repairing environmental damage that has already been done. It includes things like cleaning up beaches after an oil spill, or pumping and treating contaminated groundwater. Remediation is the “cleanup” step.

Mitigation is almost always better than remediation. Preventing a problem from occurring in the first place is usually cheaper and simpler than the costs and time involved in cleaning up a mess afterward. Unfortunately, in many cases remediation turns out to be cheaper than mitigation when someone else is paying the bills. This is because the cost of mitigation is typically borne by industry, whereas society is often stuck with the tab for remediation. As mentioned previously, this practice of passing the responsibilities for cleanup costs and other consequences of environmental damage to taxpayers is called an “externalized cost,” and a number of industries are quite good at it, including the chemical industry. The so-called environmental “Superfund” was set up by Congress in the 1970s with billions of taxpayer dollars to pay for the cleanup of chemical contamination on industrial sites where the original polluters were either bankrupt or long gone. There will be more discussion in the next chapter on some of the ways society can address the issue of externalized costs.

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_10

10.1 Should Fracking Be Banned?

In early 2020, Senator Bernie Sanders (I-VT) and Senator Jeff Merkley (D-OR) introduced a bill in the Senate called the "Ban Fracking Act," while Representative Alexandria Ocasio-Cortez (D-NY) and Representative Darren Soto (D-FL) introduced a similar bill in the House (Brown 2020). Senator Sanders stated that the legislation is intended to deny federal permits in 2021 for fracking within 2500 feet (760 m) of homes and schools, and then ban hydraulic fracturing nationwide in 2025. Sanders' web site claims that fracking is "a danger to our water supply. It's a danger to the air we breathe, it has resulted in more earthquakes, and it's highly explosive. To top it all off, it's contributing to climate change."

As explained in Chap. 7, most induced seismicity is the result of wastewater disposal, and EOR operations produce far more wastewater than fracking. Induced seismicity needs to be controlled by better regulation of the Class II UIC disposal wells, not by banning fracking. With the exception of a potentially greater frequency of stray gas in groundwater, there is no definitive evidence that the risks to air or water supplies from fracking are signficantly greater than the risks imposed by conventional oil and gas production. If by "highly explosive" Senator Sanders is referring to the fracking process itself, the rocks are cracked through the use of hydraulic pressure, not explosives. Actual explosives have not been used for well stimulation since the 1950s. If "explosive" refers to stray gas, the causes of this are not well understood and need to be investigated before linking it to fracking.

The Global Energy Institute of the U.S. Chamber of Commerce, which typically comes down on the side of industry responded to the Sanders-Merkley bill with a statement that "...a ban on fracking in the United States would be catastrophic for our economy. Our analysis shows that if such a ban were imposed in 2021, by 2025 it would eliminate 19 million jobs and reduce U.S. Gross Domestic Product (GDP) by $7.1 trillion" (Brown 2020). If accurate, such costs and job losses would be disastrous.

So is it possible to mitigate the environmental risks of fracking by banning the practice? The short answer is yes, for the actual risks from fracking. However, as has been discussed in detail throughout this book, none of the large-scale studies done so far (i.e. Kell 2011; U.S. EPA 2016; McMahon et al. 2019) have been able to show that the environmental risks from the fracking process are any more severe than the environmental risks from any other kind of oil and gas development. There is no evidence to support statements that fracking in the United States causes earthquakes or is explosive. It is important to note that the environmental risks from O&G are significantly lower than those from mining and burning coal.

A ban on fracking would essentially shut down U.S. domestic oil and gas production because all unconventional and many conventional wells require hydraulic fracturing to produce economical amounts of hydrocarbons. Some environmentalists may support this, and there is no argument that humanity needs to move away from the use of fossil fuels and into a cleaner energy future. However, our economy and technology are not yet equipped to deal with an abrupt absence of O&G, and a more gradational transition is required.

Like most issues associated with fracking, a potential ban is much more complicated than it first appears. Fracking now produces half of the petroleum and almost three quarters of the natural gas in the United States, and a widespread fracking ban would have serious consequences for the U.S. energy economy and also for the environment, with especially negative impacts on climate change. It would not achieve what environmentalists think it will achieve.

Because O&G opponents have erroneously conflated "fracking" with the production of fossil fuels in general, many environmentalists and some politicians believe that a call to ban fracking nationwide will encourage renewables to step up and fill the energy needs of the nation. However wonderful this may sound, it is highly improbable because it defies economic reality. Most electricity in the U.S. is currently fired by natural gas and coal (refer back to Fig. 9.4), and most American vehicles run on gasoline or diesel fuel. As was discussed previously in Chap. 9, abruptly converting electrical supplies and transportation over to renewables in the wake of a fracking ban would be both extremely expensive and very disruptive.

There is also a substantial misunderstanding among many people, including some who should know better that a ban on fracking will fight climate change by reducing GHG. It almost certainly will not. Those who support this idea are a missing a very important point. The oil and gas shortages resulting from a ban on fracking will require substitutes. Economics dictate that substitute energy sources use existing infrastructure.

Electricity is generated in gas-fired power plants through the use of gas turbines. The waste heat from the exhaust makes steam that drives additional turbines. Generators turned by the turbines make electricity. Neither a wind turbine nor a solar panel can make steam to run those generators. Power plant operators are unlikely to walk away from billions of dollars of existing generating infrastructure to build wind turbines. The obvious and cheapest answer to a shortage of natural gas from a fracking ban would be to substitute coal as a heat source to make steam for the turbines, and continue to use the existing generators.

Coal combustion emits nearly twice as much CO_2 per unit of heat energy as natural gas (Fig. 10.1). The significant reduction in GHG emissions by the U.S. over the past decade (refer back to Fig. 9.6) is largely due to the widespread adoption of abundant "fracked gas" to replace coal for power generation beginning in 2007. Coal is a fossil fuel produced by mining, not fracking, and banning fracking will do nothing about coal. In addition to higher GHG emissions, the coal extraction and combustion process has more widespread and severe environmental impacts on air, water, landscapes, ecosystems, and health than natural gas produced from fracked shale wells.

As domestic oil shortages develop under a fracking ban, demands for motor vehicle fuels, jet aircraft transportation, and access to petrochemicals like plastic are not likely to diminish, at least not immediately. People may eventually purchase electric vehicles or cars powered by hydrogen or some other exotic fuel, but in the short term, the simplest and quickest way to address a lack of petroleum supply is to increase imports. This will once again expose the United States to the political

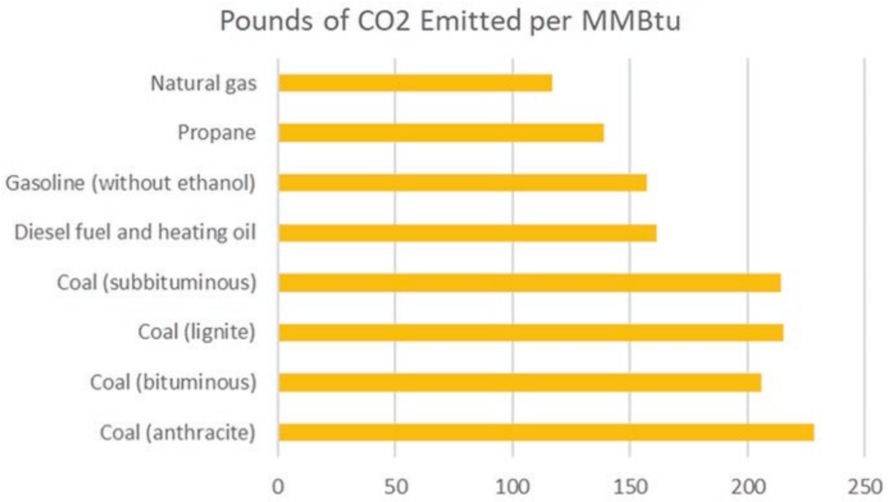


Fig. 10.1 Carbon dioxide emissions by fossil fuel type per unit of energy. (Source: U.S. Energy Information Administration)

vulnerabilities that resulted from an over-reliance on imported energy in the 1973–74 energy crisis (refer back to Fig. 4.1).

Fracking has been banned in a number of places, at least temporarily in the U.K., and permanently in the countries of France and Germany, the Canadian province of Quebec, and several U.S. states, including New York, Maryland, and New Jersey. Banning fracking was easy for Maryland, which has relatively small amounts of shale gas in only the two westernmost counties. The gas here is “dry” without the valuable condensate that makes it more attractive in West Virginia, and industry was only mildly interested in the area anyway. New Jersey doesn’t really have any significant shale gas either, except possibly some small amounts in the Triassic rift basins on the coastal plain (Milici et al. 2012), so this was also an easy decision for that state. In New York, however, it was a different story, and fracking ignited a contentious debate that raged for years.

The Marcellus Shale gas resource was first developed in southwestern Pennsylvania by Range Resources in 2007, after several years spent figuring out how to modify the Mitchell Energy horizontal drilling and staged hydraulic fracturing techniques from the Barnett to get these to work in the Marcellus (Soeder 2017). Southwestern PA was considered favorable because a number of interstate gas transmission pipelines run through the area, so there was somewhere to market the produced gas. However, from a geologic standpoint, the Marcellus thickens to the northeast and becomes even richer in organic matter, suggesting that some of the northern tier Pennsylvania counties might be more gas productive than those in the southwest. As pipeline companies began to develop capacity in the northeastern part of the state, Marcellus Shale drilling and production became focused on Susquehanna, Bradford and Tioga counties to the south of the New York state line.

Predictably, the industry also started looking at possible shale development across the border in the southern tier counties of New York.

New York soon became the epicenter for disagreements over fracking. On the one side were opponents who thought fracking would be an unacceptable risk to the environment and should be banned. On the other side were proponents who considered shale gas development to be important for the depressed New York economy, especially the rural areas upstate. The proponents had evidence that just such an economic boost had happened in Pennsylvania without major environmental impacts. Fracking opponents countered that any financial gains were not worth the risks, and that environmental impacts might take decades to become apparent (Campin 2016). The debates were intense and contentious, with vigorous disagreements over land use, landowner rights, the shared environment, water rights, and many other issues. Much of the environmental opposition came from urbanites in New York City, and was resented by proponents who were mostly rural landowners upstate. Many positions became deeply entrenched, with almost no one changing their minds about anything, and substantial hard feelings remain to this day.

One reason for the intense disagreement was the lack of data, caused by industry refusing to cooperate with outside researchers. Government regulators were also slow to respond, and their authority to force industry to allow access to sites and data was limited. Without detailed studies, environmental monitoring, and a solid understanding of the actual environmental risks, neither side had many facts to back up their arguments. The supposed environmental threats from fracking were based on anecdotes, arm-waving, and back-of-the-envelope calculations. These were dismissed by industry with claims that they had a good understanding of the fracking process and none of these problems actually existed. People on both sides became infuriated, and the attacks got personal. The degree of distrust between the two sides was palpable.

Industry by and large refused to allow independent agencies access to their drill sites to collect unbiased data that would help to ascertain the environmental risks (Soeder 2015). Some companies supplied small amounts of data and released their own environmental studies that were universally decried as “tainted” by the fracking opposition groups, who considered the information to be slanted and bogus. This argument is not without merit – other industries have delivered self-serving studies to bolster their case. The decades of obfuscation by the tobacco industry over the health risks from smoking is one example that comes to mind. Another is the denial by the pharmaceutical industry that excessive human use of drugs and hormones has affected fish and other biota in creeks and rivers. Even sugar producers have paid for studies that blame obesity on the consumption of fat, not sugar.

The New York State Department of Environmental Conservation waded into the middle of all this to carry out a detailed environmental impact study on the Marcellus Shale. They produced a massive, 1500-page Supplemental Generic Environmental Impact Statement (SGEIS) in 2009 that received thousands of public comments. It was revised in response to those comments and published in 2011 (New York State Department of Environmental Conservation 2011). The New York SGEIS concluded that no significant adverse impacts to air or water resources were likely to occur from projected Marcellus Shale development. Based on rigorous analyses, the SGEIS also provided detailed recommendations for mitigation measures and site monitoring that could be implemented to avoid any potential problems. This did not resolve the debate, but actually intensified it. Opposition groups in New York City and elsewhere in the state began pressuring the government to ban fracking no matter what the findings of the SGEIS recommended.

In 2014, after several more years of contentious debates, the governor of New York disregarded the recommendations of his own environmental agency and imposed a ban on fracking shale gas wells, citing unacceptable environmental risk (Kaplan 2014). This is a classic example of a reaction to a perceived risk, rather than an actual risk (the actual risks laid out in the SGEIS were minimal). It has been estimated that the ultimate cost of this ban to the state will be $1.4 billion in lost tax revenues and up to 90,000 direct and indirect jobs (Considine et al. 2011). New York presently imports 95 percent of its natural gas from out of state.

Other states watched this drama unfold with great interest. Fracking bans have been discussed but not implemented in Colorado and California. With little evidence of significant, widespread environmental risk, and concerns about substantial job and tax revenue losses, most states with moderate to large oil and gas industries have decided to allow fracking.

The New York ban taught the O&G industry that obtaining a “social license” for the development of shale gas and other resources is critical. Properly addressing environmental concerns up front is necessary for communities to be able to weigh the risks and benefits of allowing hydrocarbon development. This is especially important in areas without a history of oil and gas production, because the continuous nature of shale resources allows for development in previously unexplored locations where people are often unaware of the size of the industry. When landowners in non-traditional O&G locations sign a shale lease, they may not realize that they have just given permission for the construction of a five acre pad to accommodate a gigantic drill rig that will tower some 150 feet (45 m) above their rooftop. Waking up one morning and finding that in the back yard has resulted in shock at the enormous scale of the industry (refer back to Fig. 7.1). Many who were on the fence about fracking ended up opposing it once they actually experienced the reality, decrying the “industrialization” of rural America.

Have the existing fracking bans made a critical difference to the environment? It is hard to say. In Europe, fracking is banned in Germany while neighboring Denmark allows it as the Danes actively pursue gas production from the Alum Shale (Soeder and Borglum 2019). The country enforces strict standards of well site cleanliness and chemical containment, and the people and ecosystems of Denmark seem to be doing just as well as the Germans next door.

Investigations by the U.S. Geological Survey of groundwater and surface water along the New York-Pennsylvania state line 5 years after the New York ban was instituted found no significant differences in water quality between the two states (McMahon et al. 2019). One sample out of the 50 collected contained methane gas from a shallow formation that might have been mobilized by fracking activities. This remains uncertain because the migration of natural gas in shallow groundwater can have many causes, with the presence of gas wells as just one possibility (Brantley et al. 2018). Another water sample contained some hydrocarbons, but age dates of the water indicated that it was far too old to have come from Marcellus Shale fracking activity. These findings are consistent with other studies that have found localized incidents of surface water or groundwater contamination from fracking chemicals (Llewellyn et al. 2015), but no systemic, widespread contamination of groundwater from hydraulic fracturing (USEPA 2016).

The Marcellus Shale has become the single largest gas-producing formation in the United States, largely in Pennsylvania and West Virginia. The increase in tax revenue from all this gas has been significant in Pennsylvania, and royalties paid to landowners have greatly improved the balance sheets of many formerly marginal farms, especially in the northern tier counties. West Virginia has a different tax structure with mineral rights separated or "severed" from land ownership, so the state has gained revenue but landowners have benefitted far less.

A number of other states that have allowed development of their tight oil and shale gas resources have also seen substantial increases in tax revenue, including Ohio, Arkansas, Texas, Colorado, Wyoming and North Dakota. The effects in North Dakota from Bakken Shale revenue are obvious when driving into the state from surrounding regions – the roads improve significantly on the North Dakota side of the state line.

It is also important to note that not all calls for a ban on fracking are coming from concerned environmentalists. The coal industry is of course a major supporter of a fracking ban and would benefit greatly from the resulting natural gas shortages. Another player with an interest in natural gas is Russia. RT America is a cable television channel in the United States that is supported financially by the Russian government to the tune of $190 million per year. Formerly known as "Russia Today," RT America obscures its ties to the Kremlin and positions itself as a domestic U.S. channel. It frequently highlights the supposed environmental dangers and public health risks from fracking. The anti-fracking message appears to be a political response to the huge increases in domestic U.S. natural gas and petroleum production from shale over the past decade that have challenged the profitability of Gazprom, the Russian state-owned gas company, and Rosneft, the state oil company (Office of the Director of National Intelligence 2017, p. 8). In addition to lowering gas prices world-wide, U.S. shale gas exports to Western Europe in the form of LNG have directly undercut Gazprom's prime market.

Russian officials from Vladimir Putin on down have decried the "barbaric" technology involved in fracking. The intense environmental concerns about fracking in France and Germany were stirred up on social media and by Green Party commentators, yet backed by little definitive science. The resulting bans on fracking in these countries have been suspiciously beneficial for Russian natural gas exports to Western Europe. Interestingly, the Kremlin's professed concern over the "barbaric technology" of fracking does not apply to domestic production. In 2014 Gazprom partnered with Royal Dutch Shell to drill and hydraulically fracture five horizontal test wells in the Bazhenov Shale in the West Siberian basin, potentially the largest shale gas and tight oil resource in the world (Ulmishek 2003). Its successful development could return Russia to the status of top natural gas-producing country in a few short years. At this writing, the Russians are lining up future markets by negotiating to supply energy-hungry China with natural gas. They must be planning to get it from somewhere.

Although calls for a ban on fracking may be a potent campaign message and fire-up the political base, such bans don’t actually solve the environmental problems related to fossil energy and may in fact make things worse. Human civilization does indeed need to move away from fossil fuels, but in a manner that will be minimally disruptive and acceptable to most people. Naïvely labeling all the evils of fossil fuel as “fracking” is incorrect and unhelpful. There are worse things than natural gas and petroleum obtained through hydraulic fracturing, namely burning more coal and importing more oil. If fracking is to be banned, there must be solid government policies in place that force industry to transition into new and cleaner forms of energy. Just banning fracking without such policies and allowing the free market to make decisions about the kinds of energy that will replace the resulting shortages of domestic natural gas and petroleum will be a disaster.

10.2 Can Fracking Be Greener?

“Greener” fracking has been a goal of many state regulators who don’t want to ban the practice outright, but would like to mitigate some of the environmental damage being done. Many of the chemical additives currently in use are indeed quite hazardous, and if some or most of these could be replaced with safer alternatives, the environmental impacts would be reduced in the event of a leak or spill. However, any green substitute must perform as well as or better than the chemical it is replacing, and it must cost the same or less, or it won’t get used (Thomas et al. 2019). Too many grand ideas for alternative frack fluids and additives fail to consider the issues of performance and cost, and as such, they are ignored by industry.

One focus in particular is on the biocides. These are hazardous compounds by design, because they are designed to kill the microbes that get injected downhole with the frack fluid (Kahrilas et al. 2015). The water used for fracking is typically taken directly from surface streams without treatment, and whatever microbial flora and fauna happen to be present end up getting injected into the subsurface during the frack.

Some of the bacteria are known as “sulfate reducers.” As part of their metabolism, they will take a sulfate compound like sulfuric acid (H_2SO_4), strip off the oxygen atoms and reduce it to hydrogen sulfide (H_2S). Hydrogen sulfide is noted for its “rotten egg” smell and deadly toxicity. It is a gas, so it comes to the surface with the produced natural gas. H_2S is also corrosive and makes the gas “sour.” The concentration allowed into pipelines is very low, so expensive treatments are required to remove the H_2S before the gas can be sold. The best way to deal with sour gas is not to have it in the first place, so the biocides are added to prevent this.

The most common biocide in use is called glutaraldehyde (Kahrilas et al. 2016). It is a member of the aldehyde chemical family, of which formaldehyde is possibly better known. Both have pungent odors, with glutaraldehyde reportedly smelling like rotten apples. Formaldehyde was classified by the EPA in 2010 as a carcinogen (USEPA 2010), whereas glutaraldehyde is not. However, glutaraldehyde is still not "safe," as exposure may result in throat and lung irritation, asthma, breathing difficulties, dermatitis, nasal irritation, sneezing, wheezing, burning eyes, and conjunctivitis (https://www.cdc.gov/niosh/topics/glutaraldehyde/default.html; accessed 3/9/2020). Glutaraldehyde was found to polymerize into dimers and trimers (two monomers or three monomers bonded together) at downhole pressures and temperatures. It precipitates out of solution under alkaline pH conditions or high temperatures, seemingly limiting its usefulness for controlling downhole microbes (Kahrilas et al. 2016).

Other common biocides added to frack fluid include tongue-twisting chemicals like alkyl dimethyl benzyl ammonium chloride, Bronopol, chlorine dioxide, chloromethylisothiazolinone, Dazomet, dibromonitrilopropionamide, didectyl dimethyl ammonium chloride, dimethyloxazolidine, methylisothiazolione, N-bromosuccinimide, peracetic acid, sodium hypochlorite, tetrakis hydroxymethyl phosphonium sulfate, tributyl tetradecyl phosphonium chloride, and trimethyloxazolidine (Kahrilas et al. 2015, Table S-1). These have been used on various frack jobs with varying degrees of success.

Biocides are hazardous chemicals to have on-site, and must be handled carefully by the frack crews. If the containers leak and the chemicals escape, they pose a hazard to anything in the environment that encounters them (refer back to Fig. 8.1). People have been investigating less toxic biocides for frack water disinfection along with other options that don't involve chemicals additives at all. However, attempts to disinfect frack water using ozone, ultraviolet radiation, chlorination, or milder biocides either did not work very well, cost too much, or both. Some biocides like sodium hypochlorite, better known as chlorine laundry bleach, would seem to be cheap, effective, and environmentally benign. Sodium hypochlorite is a relatively simple chemical compound (NaOCl) that destroys organic material through oxidation, leaving Na and Cl (salt) behind as waste products. These are environmentally benign compared to the breakdown products of some other biocides. If chlorine bleach can be made to work consistently as a preferred biocide, and is cheaper and safer than the alternatives, it will get more use.

Another additive of concern is polyacrylamide, used as a friction reducer to create "slickwater." Polyacrylamide itself is not particularly toxic, but as it naturally degrades one of the intermediate byproducts is acrylamide, a reproductive toxin and carcinogen (Exon 2006). This environmental breakdown process is called natural attenuation or NA, and understanding the paths taken by various chemical additives as they degrade is critical for determining the point at which a compound is rendered truly harmless.

Competition is intense for developing additives that will improve the performance of fracks on specific shale plays. New chemicals are constantly being tested. Many of the formulations are proprietary, and tightly held as secrets by manufacturers. Knowledge is very limited concerning the toxicology of degradation products and the natural attenuation paths followed by many of the chemical additives used in fracking. Only a handful of NA studies have been completed to date, and none have kept up with the constantly evolving chemical landscape associated with fracking (i.e. Cluff et al. 2014; Kahrilas et al. 2015, 2016).

Thus, the regulators have no way of knowing the chemicals that are being used, and what the risks might be if a spill led to a surface water or groundwater contamination event. This is a significant concern, because it is only a matter of time before there is a release of a chemical into the environment where the toxicity and persistence are unknown. Without understanding exactly what they are dealing with, first responders and cleanup crews may be ineffective, or might even inadvertently make things worse.

Greener fracking can be encouraged by providing incentives and tax breaks to operators who substitute more benign chemicals for toxic alternatives. There also needs to be far more regulatory oversight. State agencies handle this as best they can, but many are understaffed and underfunded and in a drilling boom, it is challenging to get inspectors out to every site. Industry should pay for this in the form of much higher drilling permit fees that can be used to fund regulators. Permit fees currently in the range of hundreds of dollars can be raised to tens of thousands of dollars without unduly affecting the economics of a ten million dollar drilling program. A robust and ever-watchful regulatory program will ensure that nobody tries to pull a fast one, and that even honest mistakes get reported and remediated promptly. Industry can be counted on to complain loudly about "burdensome regulations," but if they are doing everything properly as they so often claim, they should automatically be in compliance with the regulations and have no problems.

As part of the well permitting process, state regulators should require that chemical manufacturers document every step of the NA process for new organic frack additives and run toxicology tests on each daughter compound before bringing new chemicals to market. Such data could be critically important in the event of a spill. The cost of these analyses may even encourage the use of greener frack chemicals made of simpler compounds that degrade quickly into harmless byproducts.

10.3 Remediation of Damages

So what can be done to fix all this? Oppenheimer et al. (2019) reviewed the use of expert panels by governments to help guide environmental policy and action. In many cases, governments identify and empanel experts to deliberate and decide on the scientific facts about problems like climate change, acid rain, ozone depletion, sea level rise, and other complex issues. The organization and management of these panels can affect scientific judgments, but when the scientists involved focus on the facts and evidence, their recommendations usually lead to sound policy if implemented. That last caveat is important – all the technically-sound and scientifically justified recommendations in the world won't make a bit of difference if they are not implemented as an appropriate policy.

More than a few expert panels have already weighed-in on the issue of fracking and the environment, and all of them agree that the single biggest problem is a lack of data, especially field data (e.g. Jackson et al. 2013). The U.S. Secretary of Energy Advisory Board (SEAB) recommended greater transparency and full open disclosure of all chemical constituents added to frack fluid (USDOE 2015). The U.S. EPA has called for more regulatory clarity and protection against known risks (https://www.epa.gov/uog). The Council of Canadian Academies has urged focusing on GHG emissions and water resources, especially groundwater (Council of Canadian Academies 2014). In the U.K., the Royal Academy of Engineering and Royal Society (2012) have recommended steps to reduce or eliminate induced seismicity associated with fracking. The U.K. panel also suggested that water requirements and environmental risks of fracking can be managed through operational best practices, with wellbore integrity as the highest priority, robust monitoring, and a mandatory environmental risk assessment at each site across the entire lifecycle of operations.

Some authors have proposed that a total environmental study paradigm be designed for impact analysis of fracking, similar to those done for other significant human effects on the environment, such as mountain top removal coal mining or oil sands production (Meng 2017). The argument is that the environmental impacts of fracking are much broader and deeper than current studies presume, and a systematic research structure is needed to evaluate the effects of fracking on the total environment, including an examination of the complicated relationships among different environmental elements. This may be a great idea on paper, but given the challenges of getting industry to cooperate on even modest air quality and groundwater monitoring studies, is unlikely to happen.

On a more practical note, several things can be done immediately to remediate some of the environmental damages caused by fracking and shale gas development. Controlling air pollution, water contamination, stormwater runoff, and allowing terrestrial ecosystems to re-occupy the pad will benefit both the environment and human health. Companies are not likely to implement these on their own, but if enacted as regulations by state legislatures, the requirements could be enforced by oil and gas regulators.

Air quality can be improved by ending the venting of methane and VOCs directly into the atmosphere, especially from flowback water that typically contains high VOC concentrations (Pekney et al. 2018). Flowback should be captured in closed tanks, not open pits, to keep the gases and volatiles out of the air. Methane is a powerful GHG, and VOCs contribute to smog. Complex organic molecules in VOCs, especially aldehydes will react with sunlight and moisture to form brown hazes or smog. These sunlight-driven reactions in the atmosphere create ozone, one of the most harmful pollutants in smog that can cause human health effects, harm birds and mammals, damage vegetation, and crack rubber and polymer materials. If these volatile vapors and gases must be removed from the flowback holding tanks, they should be flared instead of vented. Flaring converts methane to carbon dioxide, which is still a GHG, but a less powerful one. The combustion products of flared VOCs are oxidized compounds that are less prone to reacting with sunlight and creating ground-level ozone.

Of course, the ideal goal is to not release anything into the air at all. It is critically important that upstream producers, midstream transmission companies, and downstream distributors find and repair natural gas leaks. Since methane absorbs infrared frequencies of light as a GHG, infrared detectors can be used to identify stray gas and fugitive emissions (Soeder 2019). Many of these instruments use a laser tuned to the absorption wavelength of methane and determine the concentration by the attenuation of the beam. It is possible to deploy these instruments in drones, or make static measurements by shining a laser beam along the top of a long stretch of pipeline.

A system that is gas-tight will not only reduce GHG emissions, but will also prevent fires and explosions. Production-transmission-distribution losses from the national natural gas system may equal 1.5–2% of the total throughput (McKenna 2011). This estimate is in line with other estimates for gas leakage from the EPA and the Gas Research Institute although industry generally believes the losses are lower. These fugitive emissions have nothing to do with shale gas or fracking specifically, but are an issue with the entire natural gas distribution system nationwide.

One of the worst culprits for fugitive emissions is the old gas distribution infrastructure under our cities. Many of the original iron gas pipes laid down in places like San Francisco and Boston are more than a century old, and they leak (McKenna 2011). Along with water, sewer, and power lines, natural gas systems are an infrastructure problem in the United States suffering from age and years of neglect. The cost of digging up streets and the low price of gas have limited the enthusiasm of utility companies for repairing leaks, except in emergencies. Development of a method for sealing leaks in old gas lines without digging them up would be very useful.

The final requirement for improving air quality and reducing GHG emissions is to locate and properly P&A old legacy gas wells, which have been shown to emit significant amounts of methane (Kang et al. 2014, 2016). Again, this has nothing to do directly with shale gas and fracking, but these old wells add to the GHG burden already in the atmosphere. Many legacy wells were divested by mainstream operators when production fell off or the well watered-out. Small operators obtained these at very low prices and operated them as marginal producers or “stripper wells” that would only produce a few barrels of oil or small volumes of gas per day. The larger operators had unloaded a liability for proper P&A of the well. The small operator (sometimes consisting of only one person) would collect petroleum from the wells for a while, but eventually the site would be abandoned. These individuals typically did not have the resources to properly P&A the wells, and they would often just cut off the casing at the surface and leave an unsealed hole.

Several states, notably Pennsylvania and Wyoming have active campaigns to find old wells and properly plug them. Challenges include dealing with thousands of poorly documented wells (Pennsylvania alone is estimated to have over 100,000), missing records concerning well location and depth, casing cut flush with the surface or buried beneath brambles and dirt, a low magnetic signal because casing was removed for steel (a common way to supply Pittsburgh steel mills during WWII), and previous P&A attempts that were either done wrong, or used incorrect materials like gravel and dirt. Finding and plugging these so-called "orphan" wells that no longer have an owner is time-consuming and expensive. State funding for these activities is low, and they are proceeding at a slow but steady pace. A substantial shot of money would help the state agencies get ahead of the game to properly P&A more of these legacy old wells.

After air pollution, groundwater and surface water contamination from fracking are the second significant issue that can be remediated. Stray gas in groundwater is something that must be addressed. Research on how fracking pressure cycles might stress and de-bond wellbore cement may lead to a better understanding of the formation of microannuli that allow the upward migration of gas. Once the problem is understood, it can be mitigated by placing a stress-relief zone between adjoining casing strings, such as replacing rigid cement with a deformable putty material that will stretch instead of crack.

In terms of frack chemical additives, much more data on NA paths and rates are needed for any reasonable spill response. Even if there is a proprietary chemical that needs to be kept secret, generic NA of similar compounds would be useful, and better than nothing. A list of the breakdown paths, rates, and properties of the daughter products should be supplied by the chemical manufacturers. Some state legislatures might even consider making this a requirement prior to using the product in hydraulic fracturing.

Drill pads should have hydrologic monitoring of the site before, during, and after fracking. This can consist of a few groundwater monitoring wells around the perimeter of the pad in case any chemicals seep into the ground. There should also be surface water monitoring during the well construction and completion phase, including during fracking. Monitoring should be set up at the mouth of the smallest watershed that contains the well pad. The parameters that ought to be monitored in streams include conductivity (a surrogate for TDS), sediment load, temperature, and streamflow characteristics. Once the completed wells on the pad begin production, the monitoring equipment can be removed from the stream and used at another well site.

Landscapes should be restored as closely as possible to the original land use after the wells are constructed and completed. Water impoundments should be breached to avoid creating an "attractive nuisance." Waste material on the pad, including drill cuttings, should be removed and disposed of properly. The impervious liner of the pad itself should be removed after completion to allow water to infiltrate the soil more naturally. The minimum pad area needed for access to the wellheads, storage tanks, meters and other equipment could be maintained as open space, but the remainder of the pad should be allowed to return to a natural state.

State legislatures don't need to develop new standards, but could simply require operators to follow existing standards for pressure containment and wellbore integrity as described in Recommended Practice (RP) 100-1 and 100-2 from the American National Standards Institute (ANSI) and the American Petroleum Institute (API)

(Benge et al. 2018). Standards are also available for groundwater protection, waste management, emissions reduction, site planning, and worker training. Recommendations have been published by the Society of Petroleum Engineers (SPE) for improved production practices, enhanced environmental stewardship, expansion of non-combustion uses for crude oil, and greater social acceptance of O&G operations.

Requiring industry to follow uniform standards enforced by the permitting agencies will minimize environmental impacts from fracking and improve sustainability. As for complaints from the industry that they are over-regulated, companies operating in a responsible manner will already be meeting most of these requirements. Those who are not need more regulating.

References

Benge G., Miller, D., Miller, S., & Goodman, R. (2018). *New API standards for shale development: Paper SPE-189897-MS*. In SPE Hydraulic fracturing technology conference and exhibition, 23–25 January, The Woodlands, Texas, USA; Society of Petroleum Engineers, 6 p, https://doi.org/10.2118/189897-MS.

Brantley, S. L., Vidic, R. D., Brasier, K., Yoxtheimer, D., Pollak, J., Wilderman, C., & Wen, T. (2018). Engaging over data on fracking and water quality. *Science, 359*(6374), 395–397. https://doi.org/10.1126/science.aan6520.

Brown, D. (2020, March). Lawmakers, candidates propose nationwide ban on hydraulic fracturing. *AAPG Explorer, 41*(3), 6.

Campin, D. (2016). *Is there scientific evidence to support the selection of hydraulic fracturing rules?* SPE-179353-MS, presented at the SPE international conference and exhibition on health, safety, security, environment and social responsibility in Stavanger, Norway, 11–13 April 2016.

Cluff, M., Hartsock, A., Macrae, J., Carter, K., & Mouser, P. J. (2014). Temporal changes in microbial ecology and geochemistry in produced water from hydraulically fractured Marcellus shale gas wells. *Environmental Science & Technology, 48*, 6508–6517.

Considine, T. J., Watson, R. W., & Considine, N. B. (2011). *The economic opportunities of shale energy development* (Energy policy & the environment report no. 9). New York: Manhattan Institute for Policy Research, Inc., Center for Energy Policy and the Environment. 36 p.

Council of Canadian Academies. (2014). *Environmental impacts of shale gas extraction in Canada: Expert panel on harnessing science and technology to understand the environmental impacts of shale gas extraction*. Ottawa, ON: Council of Canadian Academies/Conseil des Academies Canadiennes. 262 p.

Exon, J. H. (2006). A review of the toxicology of acrylamide. *Journal of Toxicology and Environmental Health: Part B Critical Reviews, 9*(5), 397–412.

Jackson, R. E., Gorody, A. W., Mayer, B., Roy, J. W., Ryan, M. C., & Van Stempvoort, D. R. (2013). Groundwater protection and unconventional gas extraction: The critical need for field-based hydrogeological research. *Groundwater, 51*(4), 488–510.

Kahrilas, G. A., Blotevogel, J., Stewart, P. S., & Borch, T. (2015). Biocides in hydraulic fracturing fluids: A critical review of their usage, mobility, degradation, and toxicity. *Environmental Science & Technology, 49*(1), 16–32.

Kahrilas, G. A., Blotevogel, J., Corrin, E. R., & Borch, T. (2016). Downhole transformation of the hydraulic fracturing fluid biocide glutaraldehyde: Implications for flowback and produced water quality. *Environmental Science & Technology, 50*, 11414–11423.

Kang, M., Kanno, C. M., Reid, M. C., Zhang, X., Mauzerall, D. L., Celia, M. A., Chen, Y., & Onstott, T. C. (2014). Direct measurements of methane emissions from abandoned oil and gas wells in Pennsylvania. *Proceedings of the National Academy of Sciences, (PNAS), 111*(51), 18173–18177. https://doi.org/10.1073/pnas.1408315111.

Kang, M., Christian, S., Celia, M. A., Mauzerall, D. L., Bill, M., Miller, A. R., Chen, Y., Conrad, M. E., Darrah, T. H., & Jackson, R. B. (2016). Identification and characterization of high methane-emitting abandoned oil and gas wells. *Proceedings of the National Academy of Sciences, 113*(48), 13636–13641. https://doi.org/10.1073/pnas.1605913113.

Kaplan, T. (2014). Cuomo bans fracking, saying risks trump economic potential. *New York Times*, December 18, 2014, Page A1 of the New York edition.

Kell, S. (2011). *State oil and gas agency groundwater investigations and their role in advancing regulatory reforms: A two-state review*. Ohio and Texas: Report prepared for the Groundwater Protection Research and Education Foundation of the Ground Water Protection Council, 165 p.

Llewellyn, G. T., Dorman, F., Westland, J. L., Yoxtheimer, D., Grieve, P., Sowers, T., Humston-Fulmer, E., & Brantley, S. L. (2015). Evaluating a groundwater supply contamination incident attributed to Marcellus Shale gas development. *Proceedings of the National Academy of Sciences, 112*(20), 6325–6330.

McKenna, P. (2011). Thousands of gas leaks under Boston and San Francisco. *New Scientist Magazine*, issue 2820, p. 8–9. http://www.newscientist.com/issue/2820

McMahon, P. B., Lindsey, B. D., Conlon, M. D., Hunt, A. G., Belitz, K., Jurgens, B. C., & Varela, B. A. (2019). Hydrocarbons in upland groundwater, Marcellus shale region, northeastern Pennsylvania and southern New York, USA. *Environmental Science & Technology*, Online Publication Date: 27 June 2019. https://doi.org/10.1021/acs.est.9b01440

Meng, Q. (2017, February). The impacts of fracking on the environment: A total environmental study paradigm. *Science of The Total Environment, 580*, 953–957.

Milici, R. C., Coleman, J. L., Rowan, E. L., Cook, T. A., Charpentier, R. R., Kirschbaum, M. A., Klett, T. R., Pollastro, R. M., & Schenk, C. J. (2012). *Assessment of undiscovered oil and gas resources of the East Coast Mesozoic Basins of the Piedmont, Blue Ridge Thrust Belt, Atlantic Coastal Plain, and New England Provinces, 2011*. U.S. Geological Survey Fact Sheet 2012–3075, June 2012, USGS, Reston, VA, 2 p.

New York State Department of Environmental Conservation. (2011). *Supplemental generic environmental impact statement on the oil, gas and solution mining regulatory program: Well permit issuance for horizontal drilling and high-volume hydraulic fracturing to develop the Marcellus shale and other low permeability gas reservoirs*, Revised draft, Albany, NY, 1537 p.

Office of the Director of National Intelligence. (2017). *Assessing Russian activities and intentions in recent US elections*. Intelligence Community Assessment, ICA 2017-01D; 6 January 2017, 14 p.

Oppenheimer, M., Oreskes, N., Jamieson, D., Brysse, K., O'Reilly, J., Shindell, M., & Wazeck, M. (2019). *Discerning experts: The practices of scientific assessment for environmental policy*. Chicago: University of Chicago Press. 304 p. (ISBN: 9780226602011).

Pekney, N., Reeder, M., & Mundia-Howe, M. (2018). Air quality measurements at the Marcellus shale energy and environment laboratory site. *EM The Magazine for Environmental Managers*, August 2018, Air & Waste Management Association, 5 p.

Royal Society and Royal Academy of Engineering. (2012). *Shale gas extraction in the UK: a review of hydraulic fracturing*. Report DES2597, June, 76 p. https://royalsociety.org/topics-policy/projects/shale-gas-extraction/report/. Accessed March, 2020.

Soeder, D. J. (2015). Adventures in groundwater monitoring: Why has it been so difficult to obtain groundwater data near shale gas wells? *Environmental Geosciences, 22*(4), 139–148.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J. (2019). *Adapting a laboratory methane sensor for field monitoring*. Abstract ID: 488660; Final Paper Number: H51J-1610, American Geophysical Union Fall Meeting, San Francisco, CA, December 9–13, 2019.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

Thomas, L., Tang, H., Kalyon, D., Aktas, S., Arthur, J. D., Blotevogel, J., Carey, J. W., Filshill, A., Fu, P., Hsuan, G., Hu, T., Soeder, D., Shah, S., Vidic, R., & Young, M. H. (2019). Toward better hydraulic fracturing fluids in energy production: A review of sustainable technologies and reduction of potential environmental impacts. *Journal of Petroleum Science and Engineering, 173*, 793–803.

Ulmishek, G. F. (2003). *Petroleum Geology and Resources of the West Siberian Basin, Russia*. U.S. Geological Survey Bulletin 2201-G, 49 p.

USDOE. (2015). *Report on the multiagency collaboration on unconventional oil and gas research*, USDOE Office of Fossil Energy, Report to Congress on behalf of the Multiagency Collaboration (MAC), December 2015, 24 p.

USEPA. (2016). *Hydraulic fracturing for oil and gas: Impacts from the hydraulic fracturing water cycle on drinking water resources in the United States (Final Report): EPA/600/R-16/236F*, Washington, DC, 664 p.

USEPA (U.S. Environmental Protection Agency). (2010). *IRIS toxicological review of formaldehyde (Interagency science consultation draft): EPA/635/R-10/002C*, Washington, DC, 4 volumes, 1012 p.

Chapter 11
Balancing Energy, Environment, and Economics

Fossil fuels have powered human civilization for more than two centuries. The Industrial Revolution began in the early nineteenth century, when it was found that steam from coal could be used to drive factories, mills, ships, and trains far more efficiently than wind, water, or animal muscles. The first commercial production of petroleum by Edwin Drake in 1859 for oil lamps led to the discovery over the next half-century that this so-called “rock oil” could be used for a variety of purposes including self-powered vehicles, ships capable of long-range voyages, heavier than air flight, and electrical generation. As a technological civilization, humanity owes a huge amount of our success to fossil fuels.

Nevertheless, fossil fuels have always had an issue with sustainability. Petroleum, natural gas, and even coal resources are finite, and can only supply the energy needs of humanity for a limited time. Many people have chosen to ignore this basic fact because the future is often something no one wants to worry about, and humans in general tend to resist change and avoid uncertainty. However, the facts are the facts, and at some point we are going to need other sources of energy that are more sustainable. Fossil fuels have become at best a “bridge” to get human civilization to more technologically advanced, sustainable energy resources.

The energy resources used by any society at any time are defined by technology, controlled by economics, and directed by policy (Soeder and Borglum 2019). These three factors: technology, economics, and policy must be considered in any comprehensive, sustainable energy solution. It is also important to note that although change can be achieved by new technology, such as the advent of civilian nuclear power when uranium became available as a byproduct of Cold War weapons programs, the timing of technological breakthroughs is inherently unpredictable. Economics can also lead to change, such as the high natural gas prices that drove shale gas development, but economic conditions are unstable and can shift rapidly, as demonstrated by the ensuing glut of gas that depressed prices. The fastest and most certain way to achieve change is through policy. For example, the government of France decided years ago that most of their nation’s electricity would be generated by nuclear power, allowing France to ban fracking as a matter of policy with

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_11

little consequence. Had France been dependent on natural gas to generate electricity, a fracking ban would probably not have been possible.

The type of energy used at any particular point in human history was controlled by the level of available technology and the economics. Wood fires were used through much of history, although peat or dung might be substituted if wood was not economical. Coal replaced wood because of its greater heat capacity and availability. Oil and natural gas replaced coal with their higher efficiencies and easier mobility. Nuclear power became the ultimate energy technology in the twentieth century. New energy technology in the twenty-first century will have to be both climate-neutral and sustainable. It may include advanced nuclear systems, solar power satellites, solar-augmented or enhanced geothermal energy, and nuclear fusion.

Electricity was a breakthrough technology in the late nineteenth century that supplied power via a system of generators, wires and transformers. Electricity doesn't create energy, but merely changes it into a form that can be distributed and utilized cleanly and easily. Although there are some efficiency losses along the way, the beauty of electricity is that it can use a wide variety of primary energy sources to supply the original power. These can vary from wind to solar, coal, natural gas, hydropower, nuclear, and others. Any new and sustainable primary energy sources on the horizon will probably continue to use the existing electrical system to distribute energy.

The economics of each new technology were typically superior to whatever was used previously. This doesn't refer just to the cost of the energy source itself, but to the efficiencies gained by utilizing that new energy source. For example, a steam ship fueled by coal could move more freight faster, farther, and more reliably than a sailing ship. Likewise, a ship fueled by bunker oil could go greater distances than a coal-powered ship, and required a much smaller crew because bunker oil was pumped rather than shoveled like coal. A nuclear powered ship can go around the world multiple times without refueling. When advocates of sustainable energy push for the adoption of new energy sources, an understanding of the economic gains is a critical part of a convincing argument.

Past efforts in energy innovation, at least in government-sponsored research, were largely focused on improvements in the technology. Economics were considered only secondarily, as a goal for breakthrough technologies to provide new energy sources that were cost-competitive with existing sources. This turned out to be a mistake.

Without an economic component, most of these so-called technological breakthroughs turned out to be dismal failures. For example, no matter how much chemical engineering technology was applied to improve the efficiency of the German-developed Fischer-Tropsch process for coal gasification and liquids (refer back to Fig. 4.2), the resulting synfuel products were never able to beat or even match the price of conventional oil and natural gas. Likewise, the development of many abundant but economically-marginal hydrocarbon resources, like the Green River oil shale, the "tar sands" in Alberta and Kentucky, and methane hydrates in the deep ocean have never really succeeded because they are almost universally unable to either meet the "break even" point where the revenue from sales would match the cost of production, or to be produced at prices that could compete with conventional gas and oil.

Policy can help influence the economics of various energy options. Synfuels could have competed with conventional gas and oil if given a significant tax incentive, or if taxes on regular gasoline had been raised to provide parity on cost. Wind power would be much less economical, and perhaps even too expensive for large scale investment without government tax breaks for the installation of wind turbines. Likewise, government policies for cleaner air in cities resulted in adding ethanol to gasoline for the reduction of smog and ozone. As a biofuel, ethanol also lowers the fossil carbon GHG emissions of automobiles by at least 10%. Natural gas has been used widely for the generation of electricity after the Fuel Use Act expired in 1987, providing twice the power with half the GHG emissions of coal.

One energy development that definitely considered economics was George Mitchell's successful application of horizontal drilling and staged hydraulic fracturing to extract natural gas from the Barnett Shale in Texas. These were existing technologies that Mitchell used in a novel way, so it wasn't exactly a technological breakthrough, but more of a new application. Still, it would not have happened without the favorable economics of sky-high gas prices.

Shortages of conventional gas in the late 1990s had driven natural gas wellhead prices to historic highs of $11 to $12 per million Btu (MMBtu). These prices made the development of gas resources from the Barnett Shale economic, even though a lot of extra cost was involved in drilling the long laterals and stimulating the rock with staged hydraulic fracturing. Mitchell's success led to the subsequent development by others of the Fayetteville, Haynesville, Woodford and Marcellus shales (Soeder and Borglum 2019), but by 2010 shale gas was beginning to saturate the market. This is the point where simple supply and demand economics was forgotten as companies rushed to drill wells and get in on what was left of the shale gas boom. Because nothing had been done to increase the demand for natural gas, the prices dropped steeply to below $2 per MMBtu as supplies swelled.

Drillers and operators began to optimize drill bits, drilling fluids, and hydraulic fracturing practices for shale, improving efficiency and lowering costs. They also began focusing on the parts of shale plays that offered the best economic returns, such as areas with petroleum and natural gas liquids or condensate. Current lateral drilling rates routinely achieve a rate of penetration (ROP) of 2000 feet (600 m) or more per day, which exceeds the total lateral length on many of Mitchell's early Barnett wells. Some drillers have even attained an ROP of 1600 m per day on what are known as "MAD" (mile-a-day) wells. These enormous improvements in efficiency have maintained the economics of shale gas and tight oil, despite the price drops associated with excessive supply. New markets for cheap and abundant natural gas also became available, such as exporting LNG overseas, and using natural gas for generating electricity.

Demand for gas began to pick up (along with prices) as power plants started switching electrical generation from environmentally-complicated coal to simpler and cleaner natural gas. The technology used in gas-fired power plants turned out to be twice as efficient as coal plants, further improving the economics. Gas plants typically use “combined cycle” power generation, which employs a gas turbine that looks like a stationary jet engine to turn a generator. The hot exhaust exiting the turbine is then directed to a boiler, where it produces steam that turns a second turbine and generator. This “two-for-one” electrical generation technology is cheaper and significantly more efficient than almost any other method of electrical generation currently in use (USEIA 2018). It is being implemented because of the economics of cheap gas, but in replacing coal-fired generators it has also substantially reduced GHG emissions in the United States.

Economics alone does not always lead to beneficial energy decisions. Understanding and finding the balance among technology, policy, and economics is critical to developing and maintaining sustainable, clean, affordable energy. The wise application of policy could include tax credits or emissions taxes that will encourage or discourage the development of specific types of energy resources, such as carbon-free versus GHG-emitting for example. This is unlikely to be achieved with technological advancements or economics alone.

Many industries from retail to restaurants suffered from the COVID-19 outbreak in 2020, and the energy sector was hit hard, especially oil and gas. At this writing the pandemic is still underway, but many economists are predicting that the restructured economy after it is over will look very different from the economy that existed before. Fossil fuel may well be one of the industries facing restructuring. The economic downturn caused by the coronavirus will leave the world awash in cheap oil for quite some time, and the components of the O&G business that relied on higher prices may struggle to survive. This includes shale gas and tight oil, along with enhanced oil recovery.

Rather than waiting for oil surpluses to get used up and prices to come back, perhaps this may be an opportune time for the energy industry to switch to resources that are cleaner, greener, and more sustainable. Some ideas for these new technologies are discussed in Chap. 12, but the transition cannot happen without energy policies to support it. In an unregulated free market, cheap fossil energy supplies will win out against higher-cost options like renewables, nuclear, and geothermal. Without some substantial and wise government policies in place, the opportunity may be squandered to transition U.S. energy over to more sustainable resources.

11.1 Peak Oil

Back in the 1950s, a Shell geophysicist named M. King Hubbert (1956) developed the idea of “peak oil.” Hubbert looked at production curves from numerous oil wells, and came to the conclusion that the amount of petroleum produced from any given location over time would follow a bell-shaped curve, starting with small amounts from exploration wells, then peaking as fields were fully developed with infill and step-out drilling, and finally declining as older wells watered out, pressures dropped, and oil became an immobile phase and stopped flowing. The idea that every oil field would experience a peak in production and then drop off meant that the constant discovery of new reserves was necessary to keep up with demand. If not, the world would run out of oil sooner rather than later.

Hubbert ran some calculations based on what was known about world oil supplies and prospects in the mid-1950s, and determined that peak oil would be reached globally in the early 1970s. Although this was largely true for conventional U.S. oil resources, Hubbert missed the mark on global oil. His prediction for the date of global peak oil was pushed out several decades because large discoveries in the North Sea, South America, Australia, and Southeast Asia occurred after his paper was published. Nevertheless, Hubbert's original peak oil concept still stands: oil production in any given field will climb, peak, and then fall off. The date of peak oil in the United States has been postponed by unconventional oil and gas, but not cancelled.

Hubbert's work is often interpreted in the context of fossil energy sustainability, but surprisingly, that was not his original intention. In the mid-1950s, commercial nuclear power was on the verge of being established. As part of the hype, the infant nuclear industry bragged that electrical power from reactors would be so cheap and plentiful that it would not even need to be metered. People were told that they could have access to essentially unlimited amounts of electricity for a low, flat monthly fee. This terrified the oil, gas, and coal industries. Hubbert was trying to assess how the introduction of inexpensive nuclear electricity would impact the demand for oil and gas, and alter the peak oil curve.

At the same time the natural gas industry was reacting to the promise of cheap nuclear power by coming up with something called the "hydrogen economy." The idea was to use the waste heat from nuclear reactors to thermally dissociate water into hydrogen and oxygen, similar to the process used a century earlier to make "town gas" from water and coal, except without the carbon monoxide component. The hydrogen gas would be piped through existing natural gas infrastructure to customers. This would allow the gas industry to survive as a distribution utility, even though the transmission and production branches would wither. There were technical issues with hydrogen embrittlement of steel pipes and the fact that pure hydrogen has twice the Btu value of natural gas, which would have required retrofitting the burners on every existing gas appliance. Despite this, the fear of abundant nuclear electricity was so strong that business models were in development.

In the end, nuclear power turned out to be anything but cheap, of course. Instead of a nuclear power plant on every street corner, the total number of nuclear power plants in the U.S. never got above 110. Nuclear reactors were simply not abundant enough to make hydrogen generation practical. However, old ideas never really die, and the hydrogen economy based on surplus nuclear heat is being reconsidered as a possible alternative for GHG-free energy. Nuclear electricity emits no combustion products at all, and the only combustion product of hydrogen is H_2O, or plain old water.

Peak oil in the U.S. was reached in the late 1960s on conventional resources. This includes conventional associated gas. Non-associated conventional gas peaked about a decade later, helped by modest unconventional gas production from tight sands and coal seams. The ensuing shortages of natural gas drove prices into the

$11–$12 per MMBtu range, stoking George Mitchell's interest in shale. Despite the current high levels of O&G production in the U.S. from shale resources, peak oil is still a concern. These resources are finite; they will peak and begin to decline sooner or later. Hydrocarbons from shale should not be treated as the opportunity to continue business as usual, but instead viewed as a holding action to keep things afloat for a few more years until new, more sustainable and environmentally-friendly energy resources can be developed and brought online. As a nation, we ignore the concept of peak oil at our peril.

The decline in U.S. domestic production after peak oil was reached in the 1960s was replaced by increased amounts of imports, which resulted in the OPEC oil embargo against the United States in 1973–74 (refer back to Chap. 4). If the U.S. responds to an anticipated, similar decline in oil production from shale resources in the next decade or two in the same manner, we are going to quickly relapse into our addiction to imported oil. Except this time, we will have some stiff competition.

Both China and India appear to be repeating the U.S. playbook. These two nations together account for 20% of world oil demand, yet 70% of oil in China is imported and nearly 80% in India (Slav 2019). China is also importing significant amounts of natural gas as LNG, and is negotiating the potential development of a pipeline to bring in Russian gas. As China and India become increasingly industrialized using imported petroleum and natural gas, the potential vulnerability of the two economies to supply disruptions may be viewed by the national governments as an unacceptable risk, leading both nations to take strong actions to preserve supplies.

One would think that a substantial dependence on imported energy ought to provide strong incentives for both China and India to lead the way on developing new domestic energy resources. Although there is an interest, China is moving forward slowly and India barely at all. As things now stand, it appears that the demand for petroleum in the Chinese and Indian economies will have a major influence on world oil prices over the next decade. Coal and gas used to generate electricity in these two nations will contribute a substantial amount of GHG to the atmosphere and impact climate change. This is yet another reason for the United States to lead the way by implementing policies that will move us to greener and more sustainable forms of energy.

11.2 Externalized Costs

Fossil fuel is cheap because of externalized costs. These were explained earlier as the transfer to taxpayers, society, and future generations of humanity the cost of impacts to land, water, air, and ecosystems, and destabilization of the global climate. Because this cost is not included in the price paid for fossil energy, it undercuts the economics of every other alternative energy resource in price per Kw (USEIA 2018). The dependence of society on the fossil fuels that are leading us into a climate crisis will not be resolved as long as fossil energy has this substantial price advantage.

Billions of U.S. government and industry research dollars have been spent on alternative energy studies since the 1973–74 OPEC oil embargo, mostly focused on developing and improving new energy technologies to make them more cost-competitive with fossil. Wind, solar, biofuels, and others have made inroads in past decades to be sure, but struggled against cheap fossil energy prices the entire time. Had fossil energy been forced to pay the costs that are currently externalized, it would be far more expensive and clean energy technologies could have competed more easily on price. Higher-priced fossil fuel also reduces waste and encourages conservation, which reduces GHG emissions.

The most blatant example of an externalized cost for fossil energy is a brutal surface mining process called "mountain top removal" or MTR, used to extract Appalachian coal. Many of the "mountains" in the coal-rich regions of the Appalachian plateau are actually flat-topped, isolated tables of rock (called a mesa out west) that were carved out of the plateau by deep, water-cut ravines. The coal seams are contained within the upper parts of these tables as thin, horizontal beds overlain by a few dozen feet (meters) of sedimentary rocks known as overburden. The MTR process uses explosives and heavy equipment to strip off the overburden across the entire table and this material is then dumped into the surrounding stream valleys. The coal is excavated from the exposed seam, and the area is abandoned "as-is" once mining is complete. The site is left to weather and erode. There is no mitigation to prevent damage to the surrounding streams, and no remediation of the highly disturbed landscape. These abandoned MTR mines literally look like the surface of the moon.

Although MTR mining operations frequently cause subsequent problems to groundwater and surface water quality, decimate aquatic ecosystems, and damage the health of surrounding human populations, the coal industry is rarely held responsible. State and federal governments usually step in and perform the required cleanup. States like West Virginia perform remediation on acidic and lifeless streams as sulfides in water seeping out of the abandoned mines react with air to create sulfuric acid in the drainage. The feds have paid for stream monitoring to assess water quality impairment and determine the potential for flash floods in the disturbed and modified watershed. Human health problems are addressed by state public health agencies, and the responsibility for restoring fish populations, forests, and a stable landscape falls on various government agencies, not the coal companies. Remediation costs for an MTR project are picked up by state and federal taxpayers. The mining company that caused the damage and the power plants and steel mills that used the coal usually pay little or nothing.

Years ago, the operators of surface coal mines (popularly called "strip mines," but not by the industry) were required to restore the land to the "original contours" after mining operations were completed, plant vegetation, and generally leave behind real estate that was useful for other purposes. The industry fought these regulations, claiming that coal would become too expensive to compete with other forms of energy. They threatened to eliminate jobs, close down mines, and move operations elsewhere if they didn't get a favorable deal. Political leaders gave in, fearful of losing elections over lost jobs and not realizing that moving mining operations was largely an empty threat because there are only a limited number of places to obtain coal.

Nevertheless, a platform of saving "good coal jobs" became a part of many coal country political campaigns without ever mentioning the actual costs of these jobs to society and the taxpayers. Some MTR coal operators became billionaires, because the economics of extracting coal this way are very favorable when there are no associated cleanup or restoration costs. As a result, a few people got extremely wealthy while large swaths of Appalachia were devastated.

Like MTR coal mining, many of the costs from O&G operations are also externalized. As just one example, the process of divesting from wells that are declining in production and turning these over to small operators who eventually abandon them is one way companies avoid the costs of P&A. On a more massive scale, much of the cleanup expense for large oil spills like the Exxon Valdez or the Deepwater Horizon accidents was borne by government agencies and taxpayers. The affected locals were typically stuck with indirect costs such as the loss of fisheries or tourism. Despite the courts leveling huge fines against the responsible parties, actual corporate payouts were often substantially less.

Sadly, it is often far cheaper to retain a law firm to keep settlements tied up in the courts until fines are reduced than it is to pay the full amount of damages initially awarded. For example, an Alaska court initially fined Exxon $287 million for actual damages and $5 billion in punitive damages for the Valdez spill. Through a series of appeals, attorneys for Exxon were able to get the punitive amount reduced to $4 billion, then to $2.5 billion, and eventually to $507.5 million, which they paid, saving the company $4.5 billion over the original award (U.S. Supreme Court 2008). Most of the $2 billion that Exxon actually spent on cleaning up the oil spill was recovered through insurance claims associated with the grounding of the Exxon Valdez.

Externalizing costs has become a habit with nearly all sources of energy, not just coal. During the 1970s oil embargo, oil and gas producers received many favorable tax breaks and incentives to develop domestic resources of hydrocarbons to offset imports. Despite the amazing success of fracking that has made the United States the top producer of both petroleum and natural gas in the world (refer back to Fig. 1.2), many of these 1970s tax breaks and incentives for domestic energy resources are still on the books. Whenever anyone suggests that the subsidies be rescinded, oil industry lobbyists respond with threats of energy shortages, job losses, sky-high gasoline prices, and factory shutdowns. Congress, always fearful of losing elections, has kept them in place.

Some authors, such as Michael Liebreich of Bloomberg New Energy Finance argue that an itemized bill from society to the fossil fuel industry for externalized costs should include things like medical care for people suffering from the effects of air pollution and the military cost of defending oil tanker shipping routes and other hydrocarbon supply chains. He also claims that $69 trillion in climate-related damages will accrue between now and 2100, and if energy consumers and fossil fuel companies don't cover these, the costs will be subsidized indirectly by everyone on the planet.

Even renewable energy resources are not immune from externalized costs. Tax breaks for wind turbines have become such an integral part of the business plan for installing these units that the wind power industry claims they can't compete against coal-fired power plants without a tax subsidy. Externalizing some or most of the costs of energy production encourages waste and pollution, discourages conservation, and stifles the development of new and cleaner energy resources.

Determining the true cost of energy is difficult in the presence of subsidies, tax breaks and other externalized costs. To truly understand the economics and make a valid comparison, the cost of electricity must be "levelized" by considering externalized costs on all energy sources. In addition to fossil fuel, this includes subsidies for renewables, biofuels, hydropower, and nuclear, all of which have some degree of externalized costs.

A fair and level comparison of the cost of electricity derived from different sources shows that some of the most polluting are also the cheapest, thanks to externalized costs (USEIA 2018). For humanity to address climate change, the externalized costs that are currently paid by society must be placed squarely on those customers who actually use GHG-emitting forms of energy. This will increase the price of automobile fuel or coal-fired electricity, but it will also place the responsibility where it belongs.

There are technological solutions to climate change. For example, GHG can be eliminated from coal-fired electricity by employing technology to capture nearly all of the CO_2 emissions from the stack before they enter the atmosphere. As expected, the costs per Kw/hour will be higher than if the capture technology was not employed, but they are still comparable to the cost of nuclear electricity, which produces no GHG (Soeder 2017). This is the key to reducing the impacts of fossil fuels on climate change. Removing externalized costs to make fossil fuels more expensive will also make them much cleaner, reduce overall use, and make non GHG-emitting sources more price-competitive. In addition to the technology, such a transition will require a combination of policy and economics to provide the incentives needed to produce energy in a more sustainable manner.

11.3 Energy and Climate Sustainability

The largest externalized cost of fossil fuels is not landscape damage or oil spill cleanup, but climate change. It is important to acknowledge the size of the problem. The roots of fossil energy and climate change are built much more deeply into modern society than many people realize. Technological societies use electricity – lots of it, and most burn coal to make it.

Virtually all transport vehicles, from motorbikes to intercontinental jet aircraft run on liquid hydrocarbon fuels. Plastics are ubiquitous throughout society as structural and packaging materials and except for a few novelty plant-based items, virtually all of them are made from petroleum. Roads are paved with heavy bitumen residuals from oil refineries known as asphalt. Metallurgy uses coal and gas in the smelting and casting process. Portland cement for concrete requires high temperatures for slaking that are achieved with natural gas.

Even the manufacture of green energy products like solar panels and wind turbine blades depends on fossil fuels. The materials for these have to be mined or refined from somewhere, and it all requires energy, much of it fossil. Large trucks burning diesel fuel are needed to transport wind turbine blades and other components from the factory out to sites where they are assembled. Our civilization dictates this. Horse-drawn wagons simply will not work.

People who preach "greener than thou" in the belief that the enormous climate problem can be fixed if everyone just adjusted their consumption habits are both annoying and wrong (Marris 2020). Those with the financial resources and technical expertise to go "off the grid" by placing solar cells on the roof to charge up their electric cars are to be commended for their efforts, but these people remain an elite and wealthy minority. Some environmentalists expect everyone else to follow suit, but most ordinary people can't afford to trade in their 10-year old Toyota for a Tesla and don't have permission from the landlord to install solar panels on their apartment roof. This is reality, and blaming these people for climate change because they are forced by society to drive a gasoline-fueled car to work and use a gas stove to cook dinner misunderstands how intimately fossil energy is entangled with our technological civilization. Yes, these actions do contribute to GHG and climate change, but fixing the problem requires more than just putting up a windmill in the backyard. Personal windmills and rooftop solar panels may eliminate individual dependence on the daily use of fossil fuel, but these do not address the larger energy issues facing society. For example, how do you make steel, cement, aluminum, or many of the other energy-consumptive materials needed by society with 100 watts of energy from a rooftop solar panel?

This reality is not meant to give individuals a free pass to avoid personal responsibility for addressing climate change. To deal with energy and climate, substantial modifications will be needed in societal structures and the systems that support them. This requires grassroots support, and everyone must do their part; the contribution of each and every individual is important. Whether or not someone has gone "green" is less important than contributing one's skills and resources to help make change happen.

Some people may find it useful to join a group dedicated to energy and climate activism, where one's skill set can complement the skill sets of others, which may be very different. Another important point is to fight for something, and not just be against everything. Being constantly negative is a major turn-off that causes mainstream society to shut out the message. However, nearly everyone in society cares about the environment to some degree, and appealing to these concerns helps build a consensus for large-scale policy change. Rather than just opposing something, suggesting new ideas for what can be done instead strikes a more positive note and turns the discussion toward solutions (Marris 2020).

It is important to recognize that the magnitude of the crisis is so huge that the massive changes required to make a major switch in energy technology must come from the top, and must be world-wide. This means electing and supporting people in charge of national governments and international agencies who are willing to face reality, trust the science, pass the necessary regulations to force change, and stand up to the inevitable resistance and pushback from companies and individuals who have a stake in maintaining the status quo. Everyone on the planet who is concerned about the climate must find and support leaders who will adopt these badly-needed policies. To be blunt, politicians and other leaders who can't or won't address the issues of fossil fuel and climate change are working against the interests of the people they are supposed to be representing and ought to go find other careers.

We can't wait for the Earth to "heal itself." It will do so over time of course, but that will require geologic time. It is cold comfort that the Earth will heal itself a million years after humanity has gone extinct, and there will be no trace of our foolishness left on the planet. For the sake of our survival, we need faster solutions.

Some people think we should give up technology altogether and go back to a simpler way of life. There are two problems with this: the first is that the simpler way of life was not as grand as some romantics wish to believe. The only anesthetic for dental care in the 1700s was whisky. Surgery was performed on fully-conscious people with a bone saw. Women routinely died in childbirth and infant mortality was sky-high. Heating and cooking required firewood to be cut, split, and carried by hand. Food was either hunted, or raised on farms with a great deal of physically-exhausting manual labor. Everyone worked, including children. Transportation was by horse on land or sailing ship by sea, and it took weeks or months to get anywhere. People suffered from horrible diseases that are unheard of today. A little historical research is recommended for anyone pining away for the "good old days." Keep in mind that most of the technology we have today was invented for a reason.

The second problem with eliminating technology is that a lot of people would die. Far more humans are presently being supported by technology than the planet can sustain naturally. The production and delivery of sufficient food, clean water, housing, transportation and the manufacture of everything from clothing to medicine depends on technology and ultimately on energy. Pulling the rug out from under this will quickly lead to famine, disease, and death for a significant part of the human population.

If we intend to maintain a technological civilization and keep it running with adequate energy supplies without ruining the habitability of the Earth, what can be done? Fortunately, many things. The suggestions below include some options for technology, economics, and policy to reduce or even eliminate the impact of fossil fuels on climate change. New technology to replace fossil energy is addressed in Chap. 12.

Carbon Capture and Storage Nearly every study of energy futures concludes that humanity is not going to stop using fossil fuels overnight. In fact, these are considered to be important energy resources for at least the next 30 years. Nevertheless, the emissions of climate-changing GHG cannot simply be allowed to continue unchecked. Nearly all emissions (97%) in the U.S. come from three primary sources: electric power plants (55% of emissions), transportation (23%), and industrial processes (19%). The two worst industrial processes for GHG emissions are cement manufacturing facilities and petrochemical processing plants. The worldwide cement industry alone contributes about 5% of the total global emissions of anthropogenic CO_2 (Songolzadeh et al. 2014).

Dealing with the GHG emitted from these major sources requires capturing carbon dioxide and isolating it from the atmosphere. There are two approaches: the first captures the GHG out of the smoke stack directly from combustion products, and the second attempts to reduce the levels of CO_2 already in the atmosphere. The first approach uses a process known as carbon capture and storage, or CCS to capture carbon dioxide from fossil fuel combustion gases before it is emitted into the atmosphere. This operates directly on combustion products in the stack like the capture of fly ash or the removal of sulfur dioxide from flue gases to prevent acid rain. The captured CO_2 is stored underground in isolation from the atmosphere, or as a solid mineral phase like calcite. The second approach for removing CO_2 already in the atmosphere is a process called direct air capture or DAC. This uses biological techniques like planting trees, or mechanical techniques that remove carbon dioxide from large volumes of air. Most scientists and engineers think CCS is more practical because it is applied to concentrated sources of CO_2, whereas DAC is forced to work with very dilute amounts (even the current sky-high atmospheric concentration of more than 410 ppm is still considered to be quite dilute from a chemical engineering perspective).

In the early days of the technology, the captured carbon was said to be “sequestered,” but this term is no longer in common use. In English it implies separation, or being kept apart, as in a sequestered jury. The meaning in French culture is more sinister, equivalent to being held against one’s will or kidnapped. For the sake of international harmony, the USDOE has adopted carbon “storage,” although some have argued that what is really meant is “disposal.” However, DOE is trying to convince people that carbon dioxide can actually be a useful commodity instead of just a waste product, so the term storage is considered more desirable.

There are two basic processes for carbon capture: chemical and cryogenic (Songolzadeh et al. 2014). Membrane separation is a third potential approach, but is largely experimental at present. Chemical methods use carbon dioxide-absorbing materials like amines to grab onto CO_2 in the flue gas and then release it for storage using either a pressure drop or a change in temperature. Cryogenic techniques take advantage of the fact that carbon dioxide “freezes” out of the air at temperatures that are cold (−109.3 °F or − 78.5 °C), but still much warmer than the liquefaction point of other gases like nitrogen or oxygen. The cryogenic method essentially turns the CO_2 into “dry ice,” which can then be taken away for storage.

These techniques have an energy cost of 15% or more of a power plant’s output, and either one will raise the price of fossil fuel electricity if implemented (Kramer 2018). As such, DOE and others have been looking for various processes that can utilize the captured gas to help improve the economics of CCS (USDOE 2012). So far, the two main uses for captured CO_2 appear to be the manufacture of carbonated beverages and the re-pressurization of depleted oil and gas reservoirs for enhanced hydrocarbon recovery operations.

There are some relatively simple ways to improve the efficiency of CCS. When coal is burned in air, the concentration of carbon dioxide in the flue gases is generally less than 15% (Songolzadeh et al. 2014). Chemical absorbents are inefficient at capturing low concentrations, but the levels of CO_2 in combustion gases can be greatly increased by burning the coal in pure oxygen instead of air. This so-called "oxy-combustion" process can produce concentrations of CO_2 of more than 80% in the flue gases that can be easily captured. Of course, obtaining pure oxygen adds another cost compared to burning in plain old air, so although the capture efficiency is improved, the economics are not.

Storage of the captured carbon dioxide typically uses deep geologic formations that will keep it isolated from the atmosphere (USDOE 2012). These include depleted conventional oil and gas fields, which are known to have the capability of trapping gases underground over geologic time, coal seams that hold the CO_2 by adsorption, deep saline aquifers that hold the CO_2 in solution under great pressure, and basaltic lava rocks, which react chemically with the CO_2 and turn it into the solid mineral calcium carbonate, or calcite. All of these have pros and cons, for example, the use of depleted conventional oil and gas fields saves drilling costs by using existing wells for CO_2 injection, but also runs the risk of encountering deteriorated casing or cracked cement in old wells that might allow the gas to leak back to the surface (Watson and Bachu 2009). Storing the carbon dioxide underground as a gas or a supercritical fluid always leads to worries about potential leakage and upward migration back to the atmosphere.

Fracked gas shales are also being considered for CO_2 storage when they become depleted (Levine et al. 2016). Because the carbon dioxide adsorbs onto organic matter in the shale more strongly than methane, it might be possible to use CO_2 to "sweep" methane out of the shale pores. This could improve the efficiency of natural gas recovery from shales, while leaving the CO_2 behind in storage.

Other ideas for the storage of captured carbon dioxide away from the atmosphere include using it to cure concrete, piping it into sealed greenhouses to enhance plant growth, or feeding it to cultures of anaerobic bacteria that will consume it and give off methane gas as a byproduct. The methane could then be used for combustion, repeating the cycle.

One of the best methods for carbon storage is to inject the CO_2 into basalt. These rocks are formed from oceanic lavas rich in metals, and one of the major mineral components is a type of crystalline feldspar called plagioclase. The composition of plagioclase ranges from a sodium-rich end member known as albite, $Na(AlSi_3O_8)$, to a calcium-rich end member called anorthite, $Ca(Al_2Si_2O_8)$. Most plagioclase is a mixture of the two, combined in what is known as a solid solution series. Plagioclase is unstable at the surface of the Earth, and exposure to water and air causes it to weather into clay. The anorthite end member releases calcium into solution during this process, which reacts with carbon dioxide and oxygen to form the solid mineral calcium carbonate ($CaCO_3$), a primary component of limestone.

Field experiments run a few years ago on basalts in Iceland investigated how injected carbon dioxide would interact with the calcium-rich feldspars. The researchers were uncertain about how long calcite formation might take, but estimated the mineral reactions might require decades if not centuries. Their focus was on methods to keep the carbon dioxide from migrating into the atmosphere during those timeframes. Surprisingly, they discovered that substantial amounts of CO_2 inside the basalt had transformed into calcite in just 2 years (Matter et al. 2016). Because calcite is a solid mineral, concerns in other storage reservoirs about the potential for trapped CO_2 to leak and migrate to the surface are not an issue in basalt. Over geologic time periods, the weathering of basalt has converted most of the dense carbon dioxide atmosphere that the Earth originally possessed into calcite and limestones. Limestone formations are especially prominent in the early Paleozoic, when levels of CO_2 were higher.

There is no shortage of basalt deposits that could store CO_2. These include the Columbia River basalts in eastern Washington, Oregon, and southern Idaho, the Deccan Traps in India, the bulk of the Hawaiian Islands, Japan, Iceland, the Aleutians, and many other islands. The largest basalt volume of all resides in the Mid-Ocean Ridge system, a gigantic, subsea mountain chain that encircles the planet like the seams on a baseball. Other potential sources of calcium ions to turn CO_2 into carbonate include seawater, and brines in sedimentary rocks like those produced for salt in the nineteenth century by Samuel Kier and his contemporaries in northern Pennsylvania.

Another, similar method using asbestos is under investigation. One of the minerals making up fibrous asbestos is chrysotile, a magnesium silicate. In theory, carbon dioxide could react with the chrysotile to create magnesite, or magnesium carbonate. The fibrous nature of the asbestos minerals provides a very large surface area for the reactions.

Direct air capture (DAC) can be done using natural methods like planting trees or fertilizing the oceans to encourage plants to remove excess CO_2 from the atmosphere. However, when the plants die, the carbon has to be kept out of the atmosphere or there is no net GHG reduction. Burning the wood, for example, will just put the carbon dioxide right back into the air. There are also issues with land availability and suitability for growing trillions of trees.

A second type of DAC is mechanical removal of CO_2, using what are sometimes called "artificial trees." These employ either chemical or cryogenic methods to capture CO_2 from large volumes of air and store it underground away from the atmosphere. One advantage of the artificial tree systems is that they can be placed in deserts, tundra, on high mountain peaks, and in other locations unsuitable for growing living trees (Kramer 2018).

Mechanical DAC has a substantial capital cost and requires large-scale machinery to process enough air volume to capture significant volumes of CO_2. Systems under design or in operation (one is currently operating in Switzerland) produce CO_2 from air at costs ranging from about \$100 to \$600 per ton. Commercial CO_2 purchased from naturally occurring underground reservoirs costs \$30 to \$40 per ton

(Kramer 2018). Obviously, the economics have a way to go. However, proponents of DAC think they can turn this into a profitable operation.

Humanity currently captures and stores about five million metric tons of CO_2 per year, primarily in demonstration or pilot plant projects. This is a drop in the bucket considering that we release about 36 billion metric tons to the atmosphere annually (Source AAPG). We have the technology to prevent this carbon from entering the atmosphere, and it is past time to stop testing and start doing. The capture and storage of CO_2 in the subsurface is no more of a technical challenge than producing O&G in the first place. It comes down to a question of cost, and a question of policy.

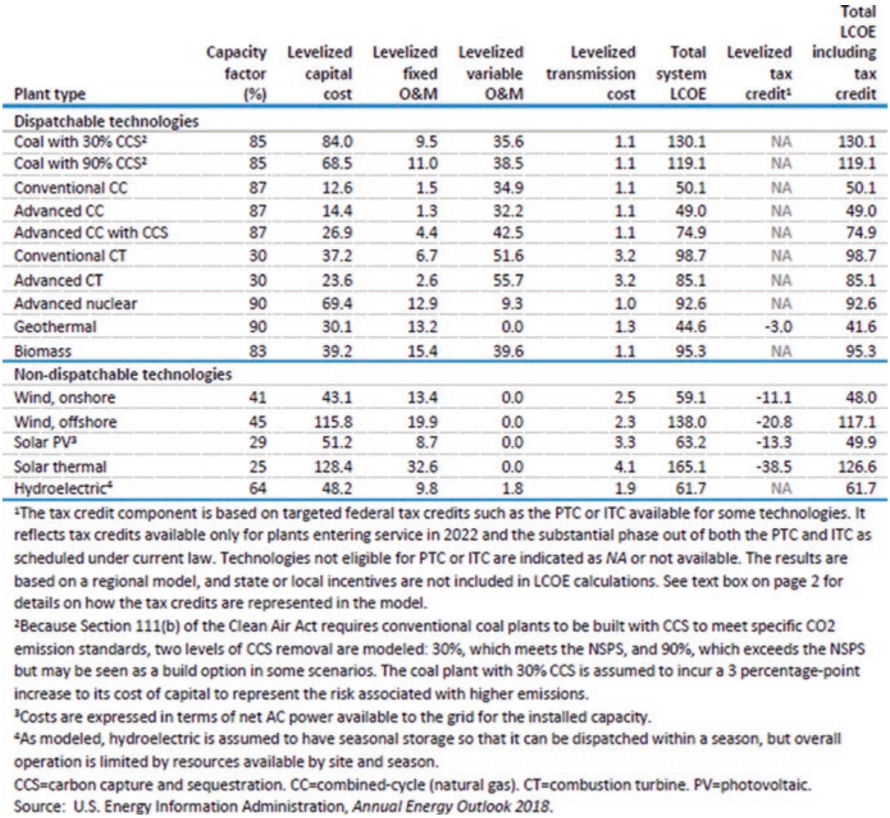
Some people think we should wait for breakthrough technologies like nuclear fusion, solar power satellites, or zero point energy to save us from climate change. If these happen, great, but the problem with technological breakthroughs is that they are unpredictable. As mentioned earlier, the longer we wait, the harder this will be to fix. We have to work with the technology we have currently available. It boils down to one basic question: Are we willing to pay more for energy to have a stable climate? If we agree as a society that this is necessary, government policy will be needed to produce laws, taxes and tax credits to make this work. Emitting GHG must have a cost penalty. Not emitting GHG through the use of CCS or by employing non-GHG forms of energy like renewals must have a cost benefit. The most sure-fire way to influence human behavior is with money. A combination of technology, economics, and policy will be required to achieve climate stability and sustainable energy.

Cost of Electricity The technical details of CO_2 capture and storage are fairly well understood. The reason this has not been widely implemented is cost. Coal or natural gas power plants that allow CO_2 and other combustion products to freely vent into the atmosphere produce the cheapest electricity. Any other option, be it carbon-free nuclear, renewables, hydro, or adding CCS to coal or gas plants raises the price of electricity. The challenge is to convince the energy-using public that this extra cost is worth it.

The U.S. Energy Information Administration (USEIA 2018) collects cost-of-electricity data and distills them down for side-by-side comparisons (Fig. 11.1). The cost of electricity shown on this chart has been "levelized" to allow different sources to be fairly compared. Levelizing makes adjustments for things like tax credits that might give one power source an economic advantage over another.

There are a number of factors that go into the final cost of electricity. These include capital expense (CAPEX), which is the funding needed to construct a power plant. It must be paid back to investors over time using a percentage of the proceeds obtained from ratepayers via their electric utility bills. Some power plants like nuclear facilities have a much higher CAPEX to recover than other power sources such as hydroelectric, where much of the cost is usually borne by government dam building programs.

The second category of expense is called operation and maintenance (OPEX), which is the revenue needed from ratepayers to actually run the power plant day-to-day and generate electricity. OPEX can vary considerably among different primary



Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	84.0	9.5	35.6	1.1	130.1	NA	130.1
Coal with 90% CCS[2]	85	68.5	11.0	38.5	1.1	119.1	NA	119.1
Conventional CC	87	12.6	1.5	34.9	1.1	50.1	NA	50.1
Advanced CC	87	14.4	1.3	32.2	1.1	49.0	NA	49.0
Advanced CC with CCS	87	26.9	4.4	42.5	1.1	74.9	NA	74.9
Conventional CT	30	37.2	6.7	51.6	3.2	98.7	NA	98.7
Advanced CT	30	23.6	2.6	55.7	3.2	85.1	NA	85.1
Advanced nuclear	90	69.4	12.9	9.3	1.0	92.6	NA	92.6
Geothermal	90	30.1	13.2	0.0	1.3	44.6	-3.0	41.6
Biomass	83	39.2	15.4	39.6	1.1	95.3	NA	95.3
Non-dispatchable technologies								
Wind, onshore	41	43.1	13.4	0.0	2.5	59.1	-11.1	48.0
Wind, offshore	45	115.8	19.9	0.0	2.3	138.0	-20.8	117.1
Solar PV[3]	29	51.2	8.7	0.0	3.3	63.2	-13.3	49.9
Solar thermal	25	128.4	32.6	0.0	4.1	165.1	-38.5	126.6
Hydroelectric[4]	64	48.2	9.8	1.8	1.9	61.7	NA	61.7

[1] The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2022 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC are indicated as *NA* or not available. The results are based on a regional model, and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[2] Because Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, two levels of CCS removal are modeled: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a 3 percentage-point increase to its cost of capital to represent the risk associated with higher emissions.

[3] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4] As modeled, hydroelectric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2018*.

Fig. 11.1 Estimated Levelized Cost of Electricity ($/MW-h). (Source: U.S. Energy Information Administration)

energy sources such as gas, coal, nuclear, solar, and wind. OPEX can even vary on a single source based on factors like percent capacity in use, seasonal factors, or other reasons (USEIA 2018). These various contributors to cost must be considered by utilities that make decisions in the real world of electrical supply and power dispatching.

The chart in Fig. 11.1 shows costs in 2017 dollars per megawatt-hour, but it attempts to project the costs for power plants entering service in 2022. The absolute numbers are less important than the relative comparison of cost among different primary power sources. Coal-fired electricity is shown with both 30% and 90% CCS. It is interesting to note that the EIA is apparently assuming that this presently externalized cost will be part of the cost of electricity by 2022, and it makes coal-fired electricity one of the most expensive options on the table. The cheapest fossil electricity is combined cycle (CC) natural gas, and the cheapest non-GHG renewables are onshore wind and geothermal, both of which receive significant tax credits. The natural gas combined cycle power is so efficient that even with CCS added on it still ranks near the middle of all options in terms of cost. Abundant, cheap gas from fracking matched with this high efficiency has been steadily displacing coal-fired power plants across the U.S. for the past decade.

Solar thermal power and offshore wind electricity are very expensive despite massive tax credits. These power sources have high CAPEX and high OPEX. Solar thermal power plants like the one constructed on Ivanpah Dry Lake in California (refer back to Fig. 9.5) require acres of precision mirrors to focus sunlight into a hot spot on a central tower. Ivanpah reportedly cost $2.2 billion to construct, which gives it a CAPEX comparable to a new nuclear power plant. Offshore wind has advantages of not occupying agricultural land or mountain ridges like onshore turbines, which some people consider eyesores. Wind turbines placed 10 miles or so (16 km) offshore from major coastal cities are still close enough to efficiently supply power, yet hidden by the curve of the Earth and invisible from land. However, offshore wind incurs the high construction and maintenance costs typical in a saltwater marine environment.

Another consideration in the cost of electricity is called “capacity factor.” This means how frequently the power source is online and generating electricity. Many of the power sources that generate “baseload” electricity, such as fossil, nuclear, and geothermal are online 85–90% of the time. Power sources like combustion turbines used for “peak shaving” only come online to meet periods of high electricity demand, and these have much lower capacity factors. Intermittent technologies like wind and solar also have low capacity factors, as do higher maintenance and seasonal technologies like hydropower.

There is no doubt that electricity will have to become more expensive to respond to climate change. Adding CCS to coal and natural gas plants to eliminate GHG emissions will consume some energy and unavoidably drive up costs, however this will also transfer the currently externalized cost of carbon management to those ratepayers actually using fossil-fuel electricity. Higher-priced fossil electricity will make non-GHG electrical technologies like advanced nuclear and enhanced geothermal more cost competitive.

There is always a potential for a CCS breakthrough technology that could bring the cost of capturing carbon emissions down to levels that will keep GHG-free natural gas as the least expensive option. Natural gas does have some advantages over the other power sources in terms of energy density, reliability, capacity factor, efficiency, and baseload power. Power plants using gas also tend to have a small footprint. The mix of various primary energy technologies listed in Fig. 11.1 can sustain us until new, exotic technologies like fusion become available.

Vehicles Despite 40 years of emissions controls, ethanol additives, and catalytic converters, gasoline-fueled vehicles still produce smog in U.S. cities. Admittedly, it is much better than it was when leaded gasoline and simple exhaust systems were the standard, but some cities still experience days where the EPA Air Quality Index exceeds 100, the danger zone for people with respiratory sensitivities.

Gasoline-powered vehicles are literally a nineteenth century technology that is well past its prime. Congress has debated for years about if, when, and how the air pollution in U.S. cities can be reduced to meet clean air standards. One answer of course is for everyone to purchase electric vehicles (EV), which create zero emissions when charged up on non-GHG sources of electricity. It is important to recognize that charging up an EV from a coal-fired power plant without CCS emits more GHG than a gasoline-powered vehicle driving the same distance.

EVs have become more affordable in past decades with improved batteries, greater range, and shorter recharge times. However, they are still out of the price range of many. Although the ranges have gotten longer, many American drivers are anxious about a vehicle not having as much range as they think they need (even though most people drive less than 100 miles or 160 km per day). For these people there are plug-in hybrid electric vehicles, which run mostly on electric but can run on gasoline when necessary.

Another, more-affordable option worth considering is natural-gas fueled vehicles, which are effective for cleaning up the air in cities. A major advantage of gas is that unlike electric vehicles, drivers are not required to purchase something new and expensive. Rather, a simple conversion allows an existing, gasoline-powered automobile engine to run on compressed natural gas, or CNG. The usual design leaves the original gasoline tank in place, and adds the CNG cylinder in the trunk or elsewhere as a second fuel source. One of these "bi-fuel" vehicles typically has a range of about 160 km (100 miles) or so on the CNG fuel, and with the flip of a switch it can run on gasoline.

The technology is neither difficult nor new, having been developed in Italy during the 1930s. The bi-fuel conversion became popular in western Canada in the 1980s, and also gained popularity in New Zealand around the same time. Converting gasoline-powered vehicles over to CNG is relatively cheap and would greatly expand the current stagnant market for natural gas. The widespread use of CNG vehicles would stop wasting valuable petroleum as fuel, which has so many other uses that powering cars with gasoline is akin to building a campfire with furniture-quality hardwood. CNG vehicles would also quickly bring U.S. cities into air quality attainment standards. It is a mystery why this has not caught on with automobile manufacturers, motorists, natural gas companies, and environmentalists.

Another issue with gasoline and diesel fuel is that these liquids are typically stored at service stations in large underground tanks for isolation from fire hazards. Thousands of buried fuel tanks all over the country have corroded over the decades and leaked BTEX and diesel-range organics (DRO) into groundwater, contaminating individual wells and in some cases, entire water supply systems. In addition to improving air quality in cities, running vehicles on natural gas would greatly reduce the underground storage of gasoline and diesel fuel, decreasing risks to groundwater throughout the nation.

Burning gasoline, diesel, and even natural gas to run a vehicle is still using a fossil fuel that will produce carbon dioxide as a combustion product. CHG emissions from transportation sources make up 23% of the total global emissions of anthropogenic CO_2 (Songolzadeh et al. 2014). Most of the current carbon capture technologies are designed for use on "fixed sources," such as power plants or industrial sites because the engineering is simpler when the carbon source is not moving.

Nevertheless, if climate change is to be addressed in a responsible manner, mobile sources of GHG emissions must be captured as well. The capture technology must obviously be scaled down to fit into a vehicle.

Fortunately, there are ways to accomplish this that have been known about and used for decades. Carbon dioxide has been removed from the breathing air in closed vessels like submarines and spacecraft through the use of chemical absorbents in the air circulation system that react with the CO_2 and bind to it chemically. Some of these reactions can be reversed and the absorbent "recharged" for another use. Perhaps carbon capture on fossil-fueled vehicles can be achieved by adding a chemical absorbent cartridge into the exhaust system. If it can be made robust enough to absorb the carbon emissions from a single tank of fuel, it can be routinely exchanged for a fresh one as part of the re-fueling process. The saturated cartridge would be returned to the factory for recharging or replacement. This is where CNG-fueled vehicles have another advantage, in that natural gas produces about 25% less carbon dioxide per Btu than gasoline or diesel fuel (refer back to Fig. 10.1).

The most common small-scale carbon dioxide capture process is called carbonatation, and uses a chemical reaction with calcium hydroxide (Han et al. 2011):

$$\mathrm{Ca}\left(\mathrm{OH}\right)_2 + \mathrm{CO}_2 \rightarrow \mathrm{CaCO}_3 + \mathrm{H}_2\mathrm{O}.$$

The end products of the reaction are water and calcium carbonate (the mineral calcite, or the rock limestone) that immobilizes the carbon. The carbon can be stored permanently as calcite, or the cartridge can be heated to separate the CO_2 from the calcium oxide, which is then exposed to hydrogen to create calcium hydroxide and re-used to capture more carbon dioxide. Economics will determine if it is more cost effective to re-charge a cartridge or simply dump out and store the calcite and replace it with fresh calcium hydroxide.

There is a similar process that uses sodium hydroxide (Yoo et al. 2013). The end products in this case are sodium bicarbonate plus water. The sodium hydroxide reaction captures two CO_2 molecules instead of just one, which makes it more efficient. However, sodium bicarbonate is less stable than calcium carbonate, so it doesn't perform as well for long-term carbon storage. If the material is being recharged for re-use, this doesn't make much difference.

If we continue to use fossil-fueled vehicles, some kind of carbon capture technology is absolutely required for the exhaust pipe. There are existing options available, and others can be developed given an incentive. The exact type of technology deployed will depend on both economics and efficiency.

Carbon Capture Technology Sulfur emissions from coal-fired power plants were a major problem back in the 1970s, when sulfur dioxide (SO_2) was combining with moisture (H_2O) in the atmosphere to create sulfuric acid (H_2SO_4). This so-called "acid rain" created by powerplants in the Midwest and Ohio Valley was falling on eastern cities and watersheds, damaging buildings, statues, and infrastructure, along with decimating forests, aquatic ecosystems, and degrading soils.

The 1990 amendment to the Clean Air Act required cutting sulfur emissions in half, and solutions were needed. A process called flue gas desulfurization was developed to prevent the sulfur dioxide from escaping into the atmosphere. This simple and effective technique adds limestone ($CaCO_3$) to the coal prior to combustion. When the coal is burned at high temperature, the limestone breaks down thermally into calcium oxide and carbon dioxide. The calcium oxide binds with sulfur dioxide to create gypsum ($CaSO_4$). Gypsum is a solid mineral that falls out of the stack gases and is recovered. The process is effective at removing 95% of the sulfur dioxide that would previously have been vented in the flue gas. Some coal-fired powerplants have drywall factories located nearby that use the recovered gypsum to make building materials.

Perhaps an equally simple solution exists for the capture of CO_2 from stack gases and vehicle exhaust pipes. As described previously, both calcium hydroxide and sodium hydroxide are known to react with CO_2 to create solid mineral phases. Perhaps other chemicals do as well. Additional studies are needed in this area to explore possible options.

Various technologies for removing CO_2 from exhaust gases using CCS or directly from the atmosphere using DAC have been presented by a number of researchers (e.g Stolaroff et al. 2008), but with little consideration given to economics or policy. The technology is important for carbon capture, but policies must be implemented to make it required and to address the economics of the added cost. The absence of a policy has made efforts to implement widespread CCS extremely difficult.

Trying to force CCS to pay for itself in an unregulated market economy is a certain failure. Claiming that CO_2 is a valuable resource rather than a waste product falls flat, because there are simply no demands for this gas that are not already being met. Counting on the economics of CO_2 sales to drive the widespread adoption of CCS is a fantasy. Even though this strategy has worked to some degree for the sulfur compounds from coal combustion in that a use has been found for the gypsum, it is important to remember that the policy requirements of the 1990 Clean Air Act amendments were the driving force behind the development of flue gas desulfurization, not the economics of drywall manufacturing.

CCS can be an energy transition technology that will allow the continued use of fossil fuels without adding GHG emissions to the atmosphere. If implemented properly and widely, CCS will buy some time for the electrical power, automotive, and manufacturing industries to develop alternatives to burning coal, oil, and/or natural gas. But until some way is found to level out the economic costs, CCS will not be widely used.

Carbon Tax The final component for the transition to sustainable energy and a stable climate is policy. Congress can always pass laws simply requiring that fossil fuel combustion products be kept out of the atmosphere, but these can be politically difficult to get in place as well as challenging to track and enforce. A better method for controlling GHG emissions might consist of both taxes and tax breaks to steer industry and individuals away from emitting carbon dioxide and encourage them to either use CCS or non-carbon energy technologies.

Many people think that a carbon tax should be levied on fossil fuels that emit GHG. Scaling the tax on the amount of carbon dioxide produced per Btu of energy by fuel type would automatically make higher GHG-emitting fuels like coal more expensive, and encourage greater usage of lower GHG fuels such as natural gas. A simple chart like that shown back in Fig. 10.1 could suffice. No tax at all would be levied on other forms of energy that emit zero GHG like wind, solar, geothermal, hydro, or nuclear. Likewise, biofuels such as ethanol would not be subject to a carbon tax because their CO_2 emissions are already part of the carbon cycle.

The goal of a carbon tax is to make fossil fuel more expensive. The tax transfers the currently externalized cost of climate change onto the consumers who are actually using the energy. The higher cost of fossil will encourage conservation and make renewables more price-competitive without the need for technological breakthroughs. Both of these actions will reduce GHG emissions. Finally, a tax will provide funding for CCS and DAC projects to capture and store carbon dioxide without the need for convoluted economic justifications. A number of states are in fact discussing Regional Greenhouse Gas Initiatives (RGGI) as a way to make economic tradeoffs between carbon emissions and energy. With a steady revenue stream coming in from a carbon tax, this gets much easier.

For decades the development of alternative energy sources sought to come up with new technology to produce sustainable, clean energy at a cost that was competitive with fossil fuels. None was ever able to do so, at least not without major tax incentives. People are unwilling to pay more for sustainable, clean energy if cheaper alternatives like coal are available. Simply raising the cost of fossil fuels through a carbon tax will level the playing field.

The details of implementing a carbon tax are best left up to the experts. It could be levied on the producers at the production point, such as the wellhead or mine, and passed on through the system to the consumer. Or it could be levied on the consumer directly, such as an excise tax added to gasoline prices or electric bills. Non GHG-emitting energy sources and fossil fuel combustion that has implemented CCS would not be subject to paying a carbon tax, and hence receive a cost incentive to compete against fossil energy. Likewise, fossil fuels used for non-combustion purposes, such as plastics manufacturing would also not pay a carbon tax.

The cost of the carbon tax has to be high enough to match or exceed the cost of CCS. If it is cheaper to install carbon capture technology than pay a carbon tax, companies burning fossil fuels will have an economic incentive to add CCS. Regulations should ensure that the cost of CCS passed on to the consumer in terms of electric prices or manufacturing costs should be equal to or less than the prices charged by non-CCS competition forced to pay a carbon tax.

The revenue stream from a carbon tax can be used to implement DAC projects that focus on reducing the existing levels of CO_2 in the atmosphere. This is critical for mitigating the effects of global climate change, and restoring the pH balance in the oceans. There are a number of ideas for ways to achieve this that include planting a trillion trees, fertilizing the southern ocean with iron to encourage a carbon-consuming algal bloom, and using mechanical devices to capture and store CO_2 from large volumes of air (Kramer 2018). Despite wishful thinking, none of these are economically viable on their own. However, with a steady source of funding from a carbon tax, many or all could be implemented, gradually lowering atmospheric CO_2 levels back to more historic values.

References

Han, S.-J., Yoo, M., Kim, D.-W., & Wee, J.-H. (2011). Carbon dioxide capture using calcium hydroxide aqueous solution as the absorbent. *Energy & Fuels, 25*(8), 3825–3834.

Hubbert, M. K. (1956). Nuclear energy and the fossil fuels. *API Drilling and Production Practice, 95*, 1–57.

Kramer, D. (2018). Can carbon capture from air shift the climate change equation? *Physics Today, 71*(9), 26–29.

Levine, J. S., Fukai, I., Soeder, D. J., Bromhal, G., Dilmore, R., Guthrie, G., Rodosta, T., Sanguinito, S., Frailey, S., Gorecki, C., Peck, W., & Goodman, A. (2016, August). U.S. DOE NETL methodology for estimating the prospective CO_2 storage resource of shales at the national and regional scale. *International Journal of Greenhouse Gas Control, 51*, 81–94.

Marris, E. (2020). Stop freaking out about the climate. *New York Times*, January 12, 2020, Section SR, p. 7 of the New York edition.

Matter, J. M., Stute, M., Snæbjörnsdottir, S. Ó., Oelkers, E. H., Gislason, S. R., Aradottir, E. S., Sigfusson, B., Gunnarsson, I., Sigurdardottir, H., Gunnlaugsson, E., Axelsson, G., Alfredsson, H. A., Wolff-Boenisch, D., Mesfin, K., & Fernandez de la Reguera Taya, D., Hall, J., Dideriksen, K., and Broecker, W.S. (2016). Rapid carbon mineralization for permanent disposal of anthropogenic carbon dioxide emissions. *Science, 352*(6291), 1312–1314.

Slav, I. (2019). The two countries dictating oil prices in 2020. *Oilprice.com*, December 15, 2019. https://oilprice.com/Energy/Energy-General/The-Two-Countries-Dictating-Oil-Prices-In-2020.html. Accessed 16 Dec, 2019.

Soeder, D. J. (2017). *Unconventional: The development of natural gas from the Marcellus shale* (GSA special paper 527). Boulder, CO: Geological Society of America Books. 143 p.

Soeder, D. J., & Borglum, S. J. (2019). *The fossil fuel revolution: Shale gas and tight oil*. Amsterdam: Elsevier. 354 p. (ISBN: 9780128153970).

Songolzadeh, M., Soleimani, M., Takht Ravanchi, M., & Songolzadeh, R. (2014). Carbon dioxide separation from flue gases: A technological review emphasizing reduction in greenhouse gas emissions. *The Scientific World Journal, 2014*, article ID 828131., 34 p. https://doi.org/10.1155/2014/828131.

Stolaroff, J. K., Keith, D. W., & Lowry, G. V. (2008). Carbon dioxide capture from atmospheric air using sodium hydroxide spray. *Environmental Science and Technology, 42*(8), 2728–2735.

U.S. Supreme Court. (2008). Exxon Shipping Company, et al., Petitioners V. Grant Baker et al.: 554 U.S., No. 07–219, 42 p. plus dissents.

USDOE (U.S. Department of Energy). (2012). *The United States carbon utilization and storage atlas* (4th ed.). Washington, DC: DOE Office of Fossil Energy. 129 p.

USEIA (U.S. Energy Information Administration). (2018). Levelized cost and Levelized avoided cost of new generation resources, *Annual Energy Outlook*, 20 p.

Watson, T., & Bachu, S. (2009). Evaluation of the potential for gas and CO_2 leakage along wellbores. *SPE Drilling & Completion, 24*(1), 115–126. (SPE 106817).

Yoo, M., Han, S.-J., & Wee, J.-H. (2013). Carbon dioxide capture capacity of sodium hydroxide aqueous solution. *Journal of Environmental Management, 114*, 512–519.

Chapter 12
Moving into the Energy Future

In the long term, fossil fuels are not sustainable. The present abundance of shale gas and tight oil is only temporary, and should be used to help switch to new, climate-friendly, long-term sustainable energy resources. Carrying on with business as usual will take humanity and the planet over a brink in the not too distant future, and the closer we get to that brink, the harder it will be to turn away. This transition must occur if human civilization and the ecosystems that support it are to have any chance for long-term survival, but make no mistake: it will not be easy. Changing the energy paradigm in the United States initially and the world eventually will require going up against a lot of entrenched oil money and fighting a huge amount of economic inertia. It will not be easy, but it cannot fail.

So what is to be done? Well, one thing we cannot afford is despair. The future of humanity, civilization, and the very Earth itself depends on us not giving up hope. It is understandably difficult for an ordinary person bombarded with bad climate news every day not to feel like this whole thing is a lost cause. But it is not, at least not yet. Energy transitions have been done before. Wood fires and muscle power were replaced with coal and steam. Coal and steam have been largely replaced with petroleum and natural gas, which in turn have given way to nuclear and renewables. The technology to make this latest transition does not have to be invented. It exists, and only needs to be implemented.

Momentous things have been done in the past when public outcry forced leaders to act. The abolition of slavery, the right of women to vote, the implementation of civil rights laws, the passage of the clean air and clean water acts, even actions to stop acid rain and end the deterioration of the ozone layer all came about because a few people got others to agree until it became an overwhelming tsunami of public support. Many of the changes mentioned above are now taken for granted, but all were said at one time or another to be "impossible."

Even environmental scientists sometimes suffer from despair with what is called "ecological grief." Those who monitor the rapid transformation and degradation of the environment are often profoundly affected by it. The loss of treasured species and habitats can feel almost like losing a loved one, and scientific researchers have

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2_12

begun to form online support groups to talk about this grief (https://www.isthishowyoufeel.com/). Grieving is part of human nature, and has its place. Still, grief cannot last forever, and life goes on. We all eventually buck up, face forward, and get on with our daily lives. That must happen with the environment, too.

Readers can take heart in the fact that humans are responsible for the damage that has been done to the environment, and therefore humans can fix it. We are not facing some insurmountable natural disaster here like the eruption of a super-volcano or a large asteroid impact. Our current dependence on fossil energy comes from a combination of easy use, easy money, and resistance to change. Switching to sustainable energy resources at this point is a matter of policy. We have the technology and we understand the economics. Policy from the highest levels of government is now required to force the transition in energy.

Technology still has a role, and developing new, more advanced energy sources can help the economics of transition. However, we can't wait for technical miracles given the urgency of the situation. We must focus on implementing existing clean energy technologies now to power our civilization without destroying the planet. Renewables are part of the solution, but renewables alone are not the answer. For starters, both wind and solar are intermittent power sources, and require the development of advanced energy storage technology before they can become major energy suppliers. The second difficulty with renewables is their low energy density, described back in Chap. 9. It takes hundreds of wind turbines covering many kilometers of landscape to produce the power equivalent of even a modest natural gas-fired generator that can be contained in a small building. Renewables have their place, but those who advocate using them exclusively to replace fossil fuel should do the math first. New geothermal and nuclear technologies are close to engineering reality, and can be integrated with existing power generating infrastructure. They can provide continuous, high-density power with zero GHG emissions, and be implemented on a large scale as substitutes for fossil fuel. These are explored in the following sections.

12.1 Technological Solutions

Climate change resulting from the combustion products of fossil fuel warming the atmosphere is a technology problem, and technology is required to solve it. Technological solutions fall into two areas:

1. We must prevent additional GHG from entering the atmosphere and making things worse. This will require CCS on any fossil fuel combustion to keep GHG from entering the atmosphere as described in the previous chapter. A carbon tax on emissions can provide an incentive to install CCS. Non-fossil, compact, base-load power sources with high energy density must be developed to replace fossil fuel in existing electrical generation facilities. Two potential non-GHG technologies are advanced nuclear power and enhanced geothermal energy. Simply

replacing the heat source in a fossil plant to boil water and make steam will allow existing generating equipment to produce electricity without GHG emissions. This has a much lower CAPEX than abandoning entire power plants in favor of renewables like wind and solar.

2. We must reduce the high levels of GHG that are already in the atmosphere and affecting the climate. This requires the development of methods to remove and sequester carbon dioxide and other GHG through direct air capture (DAC) or "negative emissions" (Kramer 2020), also discussed in Chap. 11. The technology for doing this exists, but it needs improvements in efficiency and costs. A revenue stream from a carbon tax can be used to support DAC with artificial trees, and fund other solutions that may include massive tree planting or fertilizing the oceans to create CO_2-absorbing algal blooms.

Advanced nuclear power and enhanced geothermal systems (EGS) are two existing, non-GHG technologies that can directly replace fossil fuels for generating electricity. Both of these provide heat that can create steam to turn existing turbines and generators. They can be used nearly everywhere in current power plants by replacing the natural gas or coal burner with a heat exchanger. The boilers that make steam don't care where the heat comes from, as long as it is between 200 and 400 °C. Billions of dollars invested in electrical generating infrastructure could still be used. Both heat sources are energy-dense, carbon-free, and more energy efficient than wind or photovoltaics.

Nuclear power raises images of large concrete containment domes, huge cooling towers and billions of dollars in infrastructure. That was old nuclear power. New nuclear engineering uses small, modular reactors derived from spacecraft and submarine designs that provide a heat source to boil water in a power plant. The reactors can be added together in a series as needed to provide sufficient energy to meet demands. These designs are intrinsically safe, because the reactors simply do not contain enough mass of nuclear material to generate enough heat for core meltdown, the boogeyman of nuclear power plants. Current designs use molten salt as a heat exchanger at sufficiently high temperatures to produce live steam for turbines.

Fears among the public about the risks of nuclear power are driven largely by the disasters and reactor meltdowns at Three Mile Island in the United States in 1979, Chernobyl in the Soviet Union (now Ukraine) in 1986, and Fukushima Daiichi in Japan in 2011. Although these three incidents occurred among some 450 reactors operating in 30 countries worldwide, and across more than 60 years of commercial nuclear power generation, people are still scared (Wang 2019). Like fracking, nuclear power suffers from a perceived risk that is substantially higher than the actual risk.

Risk is the product of both probability and consequences. Although the probability of a nuclear accident is quite low, the consequences can be dire. These may include immediate deaths from acute radiation poisoning, and later cancer deaths caused by long-term exposures to lower doses of radiation. The potential long-term impacts, which could manifest years to decades after an incident seem to be the most terrifying to many people, and remain a significant concern to this day in

European countries where radioactive fallout from the Chernobyl fire, smoke, and ash cloud descended.

The Three Mile Island accident officially resulted in zero deaths. The only actual radionuclide release was a small amount of krypton gas that escaped into the air. Some people claim the accident has resulted in above-average rates of cancer and birth defects in the surrounding area, but this has not been proven.

The other two incidents did produce some fatalities. The Chernobyl accident was the worst, with an official death toll of two people killed in the initial blast and an additional 29 firemen killed by acute radiation exposure while attempting to put out the reactor fire and contain the radioactivity release. Investigations by the World Health Organization and other international agencies placed the immediate death toll closer to 50, and concluded that a total of 4,000 to 9,000 people may eventually die of cancers over the long term from chronic radiation exposure (Bennett et al. 2006). Other researchers disagree and place this total much higher, between 30,000 and 60,000 potential cancer deaths because of the widespread, low-level radioactive fallout across Europe. Radiation exposures were greater than they should have been due to the reluctance of the Soviet government to report the true severity of the accident.

No immediate fatalities were reported as a result of radiation exposure in the 2011 Fukushima Daiichi accident in Japan, although a 2018 lung cancer death was linked to the accident (https://www.bbc.com/news/world-asia-45423575 accessed 2/20/20). The earthquake and subsequent tsunami that eventually led to the reactor failure resulted in a far greater number of casualties, estimated at nearly 16,000. An additional 573 deaths were attributed to stress and accidents from the evacuation of the area around the nuclear power plant (WHO (World Health Organization) 2013).

Each of these three incidents resulted in the recognition of previously unknown problems, and led to major safety improvements in nuclear facilities world-wide. Overheating of the reactor cores was the ultimate cause of the disasters at all three plants. At Three Mile Island it resulted in better control systems, more redundancy, and additional monitoring sensors in the reactor and surrounding cooling system. Chernobyl led to the abandonment of old-style, graphite-moderated reactors that date back to the Manhattan Project and burn like charcoal if they get hot enough. Fukushima showed that accounting for the natural disasters that might affect a reactor requires planning for all natural disasters, even low probability events like a tsunami. As a result of these lessons learned, nuclear power is considerably safer today than electricity generated from the early reactors of the 1950s and 1960s.

Compared to the number of kilowatt-hours of power generated, nuclear electricity is far safer than any fossil-fuel based energy (Markandya and Wilkinson 2007). Premature deaths from air pollution caused by electrical generation using coal combustion, especially lower Btu brown coal greatly exceed any fatalities from nuclear accidents, even Chernobyl (Fig. 12.1).

Developing new nuclear technology for the future will provide a significant technological solution for climate change. Many people fear nuclear energy because power plants are complex structures where a delicate balance must be maintained between the reactor temperature, cooling system, heat exchangers and power

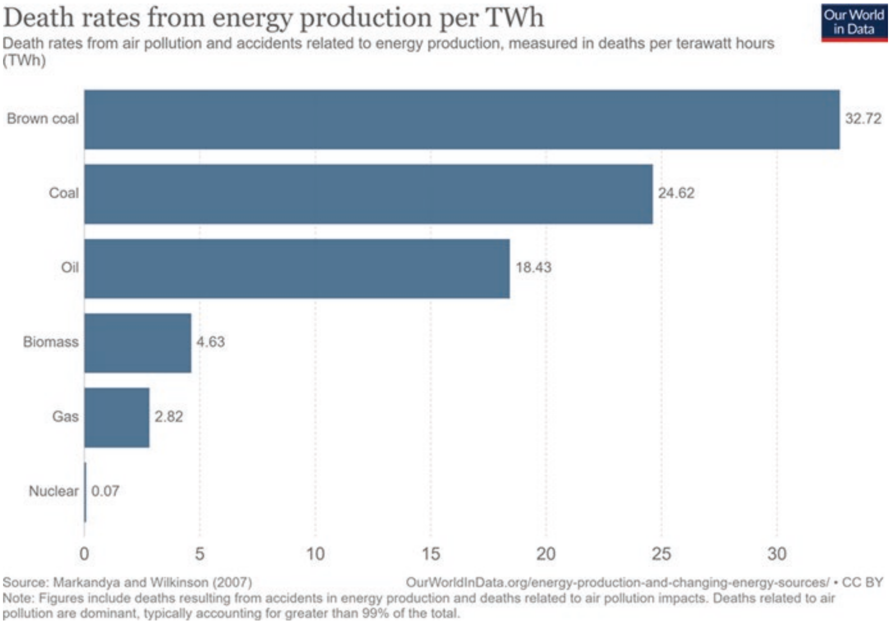


Fig. 12.1 Death rates from different forms of energy production. (Source: https://ourworldindata.org/safest-sources-of-energy; accessed 2/20/20; open access)

generation to avoid a loss of control and potential disaster. The nuclear fuel also generates significant volumes of highly radioactive waste that must be handled and disposed of properly. Utilities are reluctant to construct reactors because it must be done on site to exacting specifications with multiple inspections and complicated permits over long time periods and at great expense.

Things do not have to be done this way. Advances in the technology of nuclear reactor designs for both submarines and spacecraft can be applied to the electric power industry. Small molten salt reactors will fit into existing coal-fired and natural gas power plants as substitute sources of heat to produce steam for generator turbines. These new engineering designs employ standard architecture and are constructed in factories as modular units to speed up the licensing and commissioning process. Even in the event of a total loss-of-coolant accident, small reactors are not capable of a core meltdown as they do not contain sufficient fissionable material to reach temperatures high enough to melt. Society needs to get past the fear of nuclear energy because these non-GHG emitting energy sources are a critically important technological solution for the energy future.

The pressurized water reactors currently in use were designed in the 1950s, and use uranium as a nuclear fuel source. This is a relic of Cold War nuclear materials processing. Uranium comes in two common isotopes: $_{235}$U, which breaks apart readily and releases energy in a process called fission, and $_{238}$U, which is much less fissionable but will still do so under a strong neutron flux. The $_{235}$U isotope releases neutrons during the fission process, and when concentrated into enough mass, it can be made to explode in a “chain reaction” as the neutrons hit other $_{235}$U atoms, causing them to fission and release additional neutrons. The explosive threshold is called the critical mass, and this is how an atomic bomb works.

There is a lot more $_{238}$U than $_{235}$U in the world, so the lighter isotope must be painstakingly separated and concentrated with centrifuges, gas diffusion systems, and other sophisticated technology for use in nuclear weapons. This is difficult because the two isotopes are chemically identical, and only have about a 1% difference in weight. Power plant fuel is made from the leftover $_{238}$U mixed with about 3.5–5% $_{235}$U in what is called low-enriched uranium. It is supplied to nuclear power plants as ceramic pellets of uranium oxide for making electricity. These are stacked in tubular metal jackets to create fuel rods for running the reactor. The fission rate inside the reactor is controlled by a moderator such as water or graphite that absorbs excess neutrons and keeps the reactor core at an optimal temperature. Low-enriched uranium won’t explode into a mushroom cloud, but it does have enough fission energy to boil water, create steam and turn a turbine (Source: https://www.world-nuclear.org/; World Nuclear Association websites).

The $_{238}$U in a fuel rod is exposed to a flux of neutrons in the reactor core, where it eventually adds some weight and becomes the slightly heavier isotope $_{239}$U. This doesn’t last long, however, as the unstable atom grabs onto an electron and becomes a new element: 239-plutonium, which is both a weapons-grade fissionable material and easy to separate from the uranium chemically because it is a completely different element. About half of the $_{239}$Pu created by the neutron flux in the reactor is broken down into fission products known as daughter isotopes during the life cycle of the fuel rod.

An individual fuel rod lasts anywhere from 18 months to 3 years in a commercial reactor before it becomes “spent” or inefficient from the accumulation of daughter isotopes and has to be replaced. Uranium is a mined resource and therefore it is not considered to be renewable energy. Nevertheless, the life of nuclear fuel rods can be extended almost indefinitely by chemically removing the impurities from spent fuel and re-concentrating the fissionable materials, primarily U and Pu into “mixed oxide” or MOX pellets that can be re-used as fuel.

Such reprocessing of nuclear materials is a much more efficient use of the mined uranium resource rather than having it pass through the reactor one time only and then become nuclear waste. However, the presence of $_{239}$Pu in spent fuel rods sparked all sorts of fears about nuclear proliferation in the 1970s. Each time a fuel rod is reprocessed, the concentration of $_{239}$Pu increases in the MOX and the more desirable the rod supposedly becomes to someone who wants to use it to build an illicit atomic weapon. As such, the Carter Administration banned the U.S. from reprocessing nuclear fuel. Despite these fears, the U.K., France and Russia have been successfully reprocessing spent reactor fuel and using MOX for decades without any mishaps, and Japan is commissioning a facility to do the same. If nuclear power is to have a future in the United States, the reprocessing of spent fuel needs to be seriously reconsidered.

Nuclear proliferation concerns are pretty much old hat these days anyway. Many of the countries seeking nukes that worried the United States in the 1970s now possess them. The technology required back in 1945 on the Manhattan Project to build the first simple fission weapons significantly taxed American intellectual and financial resources. It is important to remember that this occurred 75 years ago during the age of vacuum-tube radios, party line telephones, and commercial flights on DC-3 s. By today's standards, the technology is pretty simple, and directions for constructing nukes can even be found on the Internet.

So most of the nations that wanted atomic weapons now have them, and many of these countries are finding nukes to be more of an expensive curse than a blessing. Every country that possesses atomic weapons is experiencing the same Cold War conundrum that tied the hands of the United States and the Soviet Union for decades: despite spending huge sums of money to develop these weapons, they cannot be used. Any use of nuclear weapons will only result in retaliation in kind, leading to mutually-assured destruction, appropriately known as the MAD doctrine. Climate change from fossil fuel GHG emissions is a much more likely disaster for humanity than someone randomly starting an unwinnable nuclear war. Dated fears of nuclear proliferation should not be used to stifle the development of nuclear energy as a clean, non-carbon resource.

A major barrier to the expansion of nuclear energy is dealing with the waste. The entire inventory of hundreds of fuel rods in a commercial reactor is replaced every 3 years. Over the typical 30-year operating lifetime of a reactor, this is ten full sets of spent fuel rods. Because of the difficulties involved in licensing new reactors, many existing reactors have had their operating lifetimes extended to 40, 50 or even 60 years, creating even more spent fuel. Without spent fuel reprocessing, each and every fuel rod must be handled as high-level radioactive waste. Even with reprocessing, there is still a substantial amount of high-level radioactive waste that must be safely disposed of.

The current best practice worldwide for managing this waste is to place it deep underground in a geologic repository. The goal of a repository is to keep the waste out of the environment for tens of thousands to hundreds of thousands of years until the radioactivity decays to safe, background levels. This has been a challenge because of a limited number of technically-suitable sites, an even smaller number of sites that are suitable both technically and politically.

Other nations that use nuclear power have underground repositories established in their country or access to repositories in neighboring countries for the management of high-level radioactive waste. The United States, unfortunately, has no option at present for the long-term storage of nuclear powerplant waste. This is the result of some lofty promises and ham-handed decisions made by Congress and government officials in the past that continue to haunt nuclear waste policy in the U.S. The spent fuel rods are being stored on-site at the powerplants in concrete casks, known as "dry cask storage." One of the more concerning problems about this waste is the concentration of plutonium and related heavy elements like americium that are collectively known as "transuranics." These can be particularly dangerous to life and health if a population is exposed.

Two underground nuclear waste repositories exist in the U.S.: one at Yucca Mountain in Nevada, and the other at the Waste Isolation Pilot Plant (WIPP) in New Mexico. Yucca Mountain is currently in mothballs, having been shut down in 2011 by the Obama administration before becoming operational. WIPP is accepting only weapons-grade waste from nuclear devices that are being dismantled at the nearby Pantex plant in Texas as required by the Strategic Arms Reduction Treaty.

Electric utilities would be foolish to commit to any new nuclear generating capacity when there are no existing options for the permanent disposal of the large quantities of high-level radioactive waste they already have on hand from currently-operating reactors. New, high-technology nuclear reactor designs will elicit zero interest from electric utilities until and unless the nuclear waste problem is solved. The technical basis for securely storing the waste in a properly-designed and carefully constructed underground repository is well understood as a safe and routine method for managing radionuclides to avoid potentially dire environmental consequences. Everyone else in the world is doing this. The lack of an operating nuclear waste repository in the U.S. is strictly a political issue, and it will take some responsible political leadership to resolve it.

Nuclear electricity can make an enormous contribution toward displacing fossil fuels with clean, sustainable energy that emits no GHG. The absence of a nuclear waste repository is one of the main factors halting the development of additional electrical power from advanced nuclear technology. In the context of addressing climate change, this is just as irresponsible as building more coal-fired power plants or buying more gas-guzzling vehicles. The establishment of an operational repository for high-level radioactive waste in the United States is a critical need, and should be nothing less than a top national priority.

The idea of a secure underground repository for high-level nuclear waste dates back to the beginnings of commercial nuclear power. Reactors were located relatively close to major cities to reduce the transmission losses inherent with long power lines. Cold War military planners who got paid to be paranoid began wondering about possible Soviet nuclear attacks that didn’t necessarily target the centers of major cities. What if they bombed the nearby nuclear power plants instead? A lot more deadly radioactive fallout could be created by vaporizing the reactors, and if the wind was blowing in the right direction, it would kill millions. There was little that could be done about the reactors, but if a large inventory of transuranic-bearing, spent fuel rods were stored at the power plant site and got vaporized as well, these would add substantial amounts of additional radionuclides to the mushroom cloud and make the fallout even deadlier. This scenario scared the daylights out of Cold War planners, who recommended that high-level radioactive waste be removed from populated areas such as major cities, and placed in a remote location instead.

Other motivations for placing the high-level radioactive waste deep underground in a remote location include protecting the environment and keeping transuranic-enriched spent fuel rods out of the hands of potential nuclear terrorists. It is also important to note that the end of the Cold War has not ended the threat of nuclear attack. The United States still has adversaries, including some non-state actors, who might choose to use atomic weapons. Anyone with the technical acumen to acquire and operate such devices already knows that an easy way to substantially increase the yield is to detonate one on top of a nuclear powerplant. Thus, many valid reasons remain for removing spent nuclear fuel from major cities and constructing an underground, high-level radioactive waste repository.

No technical issues have been identified that disqualify Yucca Mountain as a high-level nuclear waste repository. It is located in the Mojave Desert in an area that gets an average of four to 6 inches (10–15 cm) of rainfall in a year. It sits on government land, straddling the boundary between the Nevada National Security Site (formerly known as the Nevada Test Site), the Nellis Air Force Base bombing range, and Bureau of Land Management (BLM) land.

About the only way nuclear materials could escape from a Yucca Mountain repository is by being dissolved in groundwater and carried along with the flow. The water table under Yucca Mountain is nearly 2000 ft (600 m) below the crest. This creates a very thick unsaturated zone for storing nuclear waste in tunnels deep underground but still high above the groundwater. Movement of groundwater percolating vertically through the unsaturated zone and then flowing laterally under the mountain toward Death Valley is very slow, on the order of tens of thousands to hundreds of thousands of years. Death Valley is a closed basin below sea level with no connection to any other watersheds. Anything that ends up in Death Valley stays there.

The mountain itself is a tilted fault block composed of layers of volcanic ash called tuff that erupted some 12–13 Ma in the Late Miocene (Day et al. 1998) from an unidentified, extinct volcanic caldera probably to the north. Several of these layers are so thick that the trapped heat caused the individual ash particles to fuse together and form welded tuff, which is almost as hard as granite. As part of the site characterization studies in the 1990s, a tunnel was excavated from north to south beneath the crest of the mountain. Called the Exploratory Studies Facility or ESF, the tunnel is five miles (8 km) in length by 25 ft (7.6 m) in diameter, and large enough to handle shipments of high level radioactive waste (Fig. 12.2).

Politicians in the state of Nevada are almost uniformly opposed to using Yucca Mountain as a high-level radioactive waste repository. The reasons for this have much to do with the history of the nuclear waste program in the United States, including some heavy handed decisions that seemed expedient at the time but later turned out to be problematic.

When commercial nuclear power first became established in the mid-1950s, the U.S. Congress set up a trust fund for dealing with the anticipated large volumes of high-level radioactive waste. Income for the trust fund came from a tariff imposed on nuclear-generated electricity. This fund was used to support the characterization and design of a permanent repository for the high-level radioactive waste. When the nuclear waste fund was established, it was expected that an operational repository would be available to accept power plant waste by the early 1980s.

An underground repository option for high level waste had been recommended by the National Academy of Sciences in 1957. The idea behind a “repository” was that the waste could be monitored, and even retrieved if necessary due to corrosion and leakage of a storage canister, or in case large stocks of fissionable materials

Fig. 12.2 View down the North Ramp of the Exploratory Studies Facility inside Yucca Mountain. (Photographed in 1997 by Dan Soeder)

were needed for some future, unknown technical or engineering application. In the meantime, isolating the waste deep underground would keep it secure and protect both the environment and public health.

A national policy to deal with high-level nuclear waste came about in 1982, with the passage of the Nuclear Waste Policy Act. This law made the U.S. Department of Energy (DOE) responsible for locating a suitable site and constructing a geologic repository for nuclear waste. It also moved back the date for the U.S. government to accept nuclear waste to January 31, 1998. This concerned many nuclear power plant operators because the waste holding capacity of their facilities had been designed with the original “early 1980s” waste acceptance date in mind.

DOE initially investigated ten different potential repository locations across the country, with geology that varied from shale to bedded salt to volcanic rocks. There were three minimum technical requirements for a repository:

- The site must be remote, stable, and on land either controlled by the government or easily acquired by the government.
- Groundwater travel times from the nuclear waste storage area to the accessible environment must be at least 10,000 years and the longer the better.
- The site must contain no existing natural resources of any consequence that someone might try to drill or mine in the future.

Other factors like accessibility and distance from population centers were also given some consideration, and by the mid-1980s, DOE had selected three locations that would be fully characterized for suitability. These were a bedded sedimentary salt in Deaf Smith County, Texas southwest of Amarillo, the Columbia River basalt flows at the Hanford Site north of Richland, in east-central Washington state, and the welded tuffs at Yucca Mountain, on the western border of the Nevada Test Site. The 1982 Nuclear Waste Policy Act had directed DOE to carry out full technical assessments of the three top candidate sites, and then select the best one based solely on technical merits.

However, before any meaningful site characterizations could get underway at these three locations, Congress intervened. An amendment to the Nuclear Waste Policy Act in 1987 halted the investigations at Deaf Smith in Texas and Hanford in Washington, and designated Yucca Mountain in Nevada as the only site that would be fully characterized for a high-level radioactive waste repository. This wasn't just done on a whim – it was a sincere attempt to save some ratepayer money and there was some sound technical reasoning behind this decision.

The Deaf Smith County location was on privately held land, and the federal government would have had to acquire it at substantial cost. The target horizon for storing the nuclear waste was a bedded sedimentary salt about 1000 ft deep (300 m), which was considered to be a stable formation with little to no groundwater movement (salt is highly soluble, so if there was significant groundwater flow, it would not be there). Local farmers became concerned about the negative impacts of a repository on agriculture, and political opposition grew rapidly, with as many as 80% of the people in the county and surrounding counties eventually claiming to be opposed to the repository (Easterling and Kunreuther 1995).

Of even greater concern was that in order to reach the salt formation, the Deaf Smith repository shafts were required to penetrate the important Oglala and underlying Dockum Group aquifers, which are critically important water resources for crop irrigation. Despite reassurances from DOE officials, the idea of excavating a shaft through two aquifers and connecting them to a bedded salt raised red flags about creating flowpaths and placing water resources at risk for the sake of nuclear waste storage. Stiff local opposition, worries about groundwater risk, and turbulent Texas politics were the main factors that led DOE to walk away from Deaf Smith County as a potential site. Unfortunately for the workers hired and transferred into northern Texas for the planned characterization studies, the small town of Hereford quickly became an oversaturated real estate market as hundreds of people tried to sell houses with nearly everyone else moving out.

The Hanford Site straddling the Columbia River in eastern Washington State had been on federal land since 1943, when it was acquired under the Manhattan Project to manufacture plutonium for the first atomic bombs. Hanford has many existing environmental problems related to the frantic weapons development and manufacturing practices employed to keep ahead of the Soviets during the Cold War. Proper waste disposal was not a high priority during this time. A number of very large and partially-buried storage tanks were filled with mixed nuclear and chemical waste, some of which has leaked into the groundwater. No one quite knows the magnitude of the contamination because records of what was put into the tanks are sketchy at best. Hanford has been undergoing massive cleanup operations since 1989 (source DOE websites).

A repository design at Hanford was complicated because the individual basalt flows are not thick enough to accommodate a repository within a single unit. Cutting tunnels across multiple basalt flows would potentially provide groundwater flow paths along the contacts between the layers, and the highly fractured basalts may also have a direct hydraulic connection to the Columbia River in some locations. The potential for extremely short groundwater travel times became a show-stopper for Hanford. Thus, the intention of Congress in 1987 was to save time and money by amending the Nuclear Waste Policy Act to focus solely on Yucca Mountain as the most viable of the three sites. The state of Nevada at the time had two Senators and only one Representative in the House, and they were unable to drum up enough support to stop the bill from passing.

The 1987 amendment to the Nuclear Waste Policy Act created a huge amount of resentment in Nevada for being singled out as the only state in the country forced to host a “nuclear waste dump” at Yucca Mountain. The legislation became known locally as the “screw Nevada bill” (Fig. 12.3), and opponents of nuclear power used it to stoke public anger and raise state-wide political opposition over this “arbitrary” law.

Nevada resisted the Yucca Mountain repository with a steady series of legal, technical, and political challenges. Cumulatively, the constant legal and political battles slowed site assessment down to a crawl and raised costs substantially. The level of detail required for site characterization and site performance assessments increased as Congress kept changing the performance requirements to try appeasing Nevada politicians. In fact they had no desire to be appeased because the radioactive

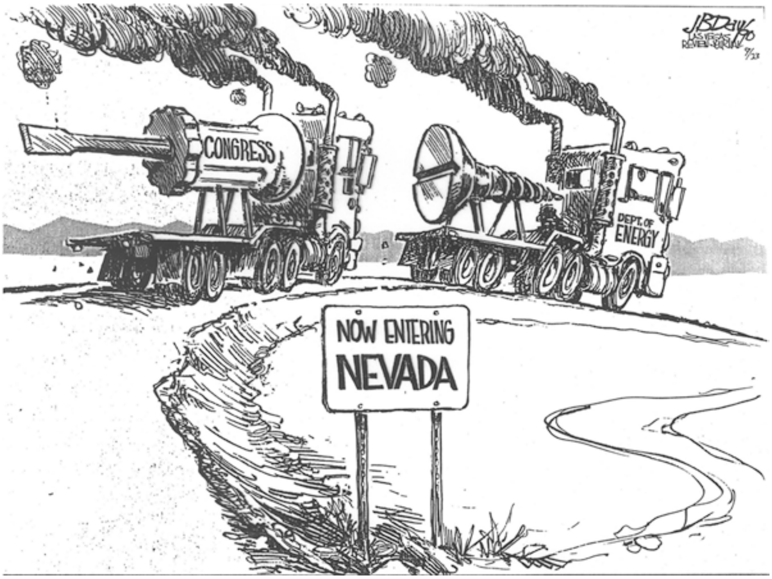


Fig. 12.3 Editorial comment in a Nevada newspaper on the 1987 amendment to the Nuclear Waste Policy Act. (Source: Las Vegas Review-Journal, 1990)

waste issue was perfect for firing-up the political base on topics like interference by the federal government on states' rights and Washington over-reach, both popular themes in Nevada and other western states. As a result, the Yucca Mountain program ended up years behind schedule and significantly over budget.

Every potentially negative finding at Yucca Mountain, no matter how minor, was amplified by opponents into a reason to shut down the site for good. For example, minerals found inside a fault adjacent to the mountain were interpreted by one scientist as a hydrothermal deposit that had been brought up from below, which would have caused serious problems with site suitability. Other investigators had determined that these mineral deposits originated from rainwater percolating downward from above through calcite-rich soils, and had no effect on the performance of the site to contain nuclear waste. Nevertheless, because of the media attention and political posturing, literally millions of dollars were spent to investigate the origin of these fracture fillings. The fracture fill was eventually revealed from stable isotope analyses to be a low-temperature mineral deposit very similar to existing soil minerals, and quite different from other known high-temperature hydrothermal deposits in the region (Paces et al. 2001). Neither this issue nor other alarms raised during the site characterization process were able to show any fatal flaws demonstrating that Yucca Mountain was technically unsuitable as a repository for high-level radioactive waste.

The slow pace of site characterization at Yucca Mountain meant that the government was unable to take possession of powerplant high-level nuclear waste in 1998, as required by the Nuclear Waste Policy Act of 1982. The nuclear power industry began legal proceedings against DOE for violating the law and forcing the industry to continue to hold the waste in "dry cask" storage at nuclear power plant sites around the country. The government settled by paying the electric utility companies compensation of $300 to $500 million per year for retaining the waste. This money was coming from funds that the utility companies had already paid into the nuclear waste trust fund to construct a repository, so the solution was less than satisfying.

In 2011, the Obama administration withdrew the license application submitted to the Nuclear Regulatory Commission by DOE for the Yucca Mountain Repository and shut down all efforts to construct and operate a high-level radioactive waste repository in Nevada. This action also ended spending from the nuclear waste trust fund. The Nuclear Energy Institute and the National Association of Regulatory Utility Commissioners filed a lawsuit in 2013 with the U.S. Court of Appeals for nuclear utilities to stop paying fees into the nuclear waste trust fund until either Yucca Mountain is opened as the official nuclear waste repository as designated by the 1987 amendment to the 1982 Nuclear Waste Policy Act, or Congress changes the law. The court found in favor of the plaintiffs and the fee ended on May 16, 2014.

President Obama appointed a Blue Ribbon Commission after the shut-down of Yucca Mountain to review possible options for nuclear waste disposal (Hamilton and Scowcroft 2012). The report from the commission recommended pursuing a multi-point strategy including state and local government consent prior to siting future nuclear waste facilities, designating a new organization (i.e. anyone but DOE) to implement a nuclear waste management program, and improving preparations for the eventual large-scale transport of high-level waste to geologic disposal facilities, a weak link in the Yucca Mountain Project. The commission also expressed hope that the development of a repository would help the U.S. to innovate in nuclear energy technology, and provide leadership in international efforts to address nuclear safety, waste management, non-proliferation, and security issues.

The failure of Yucca Mountain has left the future of nuclear power very uncertain. The trust of the nuclear power industry in the government has been eroded by the lack of a coherent nuclear energy policy and the inability of the government to follow the nuclear waste policies already in place. However, even in Washington, they eventually figure out that killing a project does not necessarily solve the underlying problem. The United States currently has no solution for dealing with the high-level radioactive waste from the nearly 100 nuclear reactors operating around the nation, let alone any new reactors that might be added to fight climate change.

Huge amounts of time, effort, and money have been spent on Yucca Mountain. Investments in the site include a five-mile long tunnel complex, numerous drill holes, aquifer tests, detailed geologic mapping, seismic surveys, geochemical investigations, and physical studies of the response of the rock to heat and radiation. Massive amounts of information are available concerning the performance of the site. No show-stopping technical flaws have been found. Walking away from all this and starting over from scratch someplace else for reasons that are almost exclusively political would be a huge squandering of time and fiscal resources. There is also no guarantee that the heavy-handed approach that so alienated the people of Nevada wouldn't have the same result anywhere else.

High-level radioactive waste disposal has evolved from a technical issue into a political and legal battle that has produced nothing but volumes of Byzantine regulations, the near-impossibility of licensing new reactors, and a lack of interest in nuclear engineering among U.S. students. In the meantime, levels of GHG in the atmosphere have continued to rise, while nuclear energy is ignored as a viable alternative. This is now a political issue, and as such, it requires a political solution. Yucca Mountain might be salvageable as a high-level nuclear waste repository if a new approach is taken and some basic criteria are honored. Four suggestions are given below.

1. Negotiate with Nevada. People resent the federal government barging in and just making decisions without consulting local officials and residents. Nevada as a state is famously agreeable to nearly everything, including drinking, gambling, and prostitution as long as it is regulated and taxed. Despite this, no one in DOE had actually approached the state or local governments in the beginning and asked them what it might take to get their constituents to accept nuclear waste. There was an assumption among federal agencies that if it had been okay to set off nuclear weapons at the Nevada Test Site for 30 years, no one should mind the government storing nuclear waste out there as well. However, people did mind, because this was kind of a last straw for being taken advantage of by nuclear programs. DOE would have received a lot more support for a repository if they had demonstrated some benefits to the population of the state for accepting the

waste, such as financial payouts, new infrastructure, etc. There is still an opportunity to do this, but the cost is likely to be quite a bit steeper.

2. Build the facility using local companies and contractors. DOE typically contracts with the so-called “beltway bandits” in Washington, D.C.; large companies with three-letter acronyms for names located around the Capital Beltway that thrive on Department of Defense and other government contract work. These organizations were in fact brought in for most of the Yucca Mountain site characterization studies, which created resentment among local engineering and natural resource companies. For the construction of the repository, a strong effort should be made to recruit local talent, including skilled miners who worked both surface and underground mines in the Nevada gold industry, as well as a variety of trade and construction workers who built up Las Vegas over the past few decades. Tapping into this talent pool for jobs will create much more support for the repository than contracting the work out to big companies in D.C.
3. Designate and design Yucca Mountain as a “monitored, retrievable storage” facility instead of a permanent high-level radioactive waste repository. The classification as “permanent” runs into all sorts of regulatory hurdles, some of which are still unsettled, in terms of how radionuclides are stored and how long they have to be kept out of the accessible environment. Current options for storage duration requirements range from 10,000 years to a million years. Depending on which one of these is selected, the engineering designs are very different. Monitored retrievable storage is much less onerous from a regulatory standpoint, and allows any canisters that are corroding or damaged to be identified, recovered and repaired. In the event that a “perfect” site for a permanent repository is eventually found (on the moon, perhaps, where there is no water to corrode canisters and no environment to contaminate) the waste can be recovered, removed and transported to the new location.
4. Figure out a workable transportation option. Getting high-level nuclear waste out of the powerplants, which are mostly in the eastern U.S. to Yucca Mountain in the west runs into a host of logistical problems that would probably be similar for any remote site. Highways and railroads are both designed to connect population centers like cities together. Therefore, any long distance transport of the waste by truck or train will eventually have to pass through populated areas, even if “bypass” routes are followed. Some of these are cities like Flagstaff, Arizona, sitting astride a major coast-to-coast highway and a major east-west railroad line, which has declared itself to be a “nuclear free zone” to block the transit of radioactive waste. Once a waste transport truck does get to Nevada, the only road that passes near Yucca Mountain is U.S. 95, a two-lane highway at that point. There are no existing railroads near Yucca Mountain at all, and a long rail spur would have to be built from Las Vegas or possibly Caliente to reach it. Any nuclear waste passing through Las Vegas by train would follow the rail line adjacent to the Strip, which is not going to please the owners of fancy Las Vegas resorts. The construction of either an improved highway or a rail extension to Yucca Mountain will be very expensive.

A transportation option that has not been seriously considered but avoids nearly all of these problems is to bring in the waste by air. For infrastructure, this only requires that a runway or landing strip be constructed near the repository entrance portal. Existing military cargo aircraft that can handle canisters of high-level nuclear waste include the C-5 Galaxy and the C-17 Globemaster. These are heavy transport aircraft operated by the Air Mobility Command of the U.S. Air Force, who are experts at moving heavy cargo like M-1 Abrams tanks from place to place around the world. Transport canisters for radioactive waste can be designed to meet weight and size requirements for these aircraft, and shielded to protect the pilots and crew from radiation exposure during transport. A transport canister would undoubtedly have different properties than a storage canister because the requirements are very different. The waste would be transferred at the destination into specialized storage canisters before going underground, allowing the transport canisters to be reused.

Aircraft have several advantages over ground transport. They can fly routes that avoid population centers, keeping the waste away from cities and "nuclear free zones." Air transit is also much faster than ground options, ensuring transit times for the waste that are short, reducing chances for mishaps that come from being "on the road." According to some calculations, trucks and other road vehicles have a risk of accidents per mile traveled that is hundreds of times greater than aircraft. The majority of aircraft accidents that do occur are weather-related, but since cargo planes do not have to fly on a fixed schedule, the flights can be restricted to routes and periods with good weather. Nuclear security concerns about bad actors trying to hijack trucks carrying transuranic waste are minimized when high-flying cargo planes with fighter escorts are used. This kind of new thinking is needed for Yucca Mountain or any other repository site to become viable for storing high level radioactive waste, and allowing the nuclear power program to have a new lease on life.

Along with new, standardized reactor designs that are much less prone to overheating and meltdown, other fuel options are available as well. As explained earlier, the $_{235}$U-$_{238}$U-$_{239}$Pu fuel cycle used in current nuclear reactors is a relic of the Cold War atomic weapons manufacturing process. A different fuel cycle can be based on thorium instead (IAEA 2005). Thorium itself does not fission, but is known as a "fertile" element in reactors. When exposed to a neutron flux, thorium will undergo a series of nuclear reactions that eventually result in the creation of the light uranium isotope $_{233}$U. This isotope is fissionable, and breaks down into lighter daughter elements. It does not produce the heavy transuranic elements like plutonium, americium, and curium that come from irradiating $_{238}$U. Avoiding transuranics in the nuclear waste makes it much less toxic over long time scales, and the absence of plutonium renders it useless to those seeking to manufacture weapons. The future of nuclear power will be defined by new reactor technology, new fuel cycles, a reduction in the costs and commissioning times for new reactors, and an agreed-upon policy and plan for dealing with high-level nuclear waste.

Geothermal energy in the past was restricted to volcanic areas with geysers or hot springs. Unfortunately, these are rarely located where the energy is needed. Enhanced geothermal systems (EGS) technology allows heat to be extracted from the crust of the Earth at extreme depths anywhere in the world. EGS utilizes the fact that everywhere on Earth has a geothermal gradient, where the heat of the rock increases with depth (USDOE 2016). Some of this is primordial heat left over from when the Earth accreted from smaller objects some 4.5 Ga, but most of it is generated from the decay of naturally-occurring radioactive elements in the subsurface rocks. A borehole drilled deep enough anywhere on Earth will eventually encounter rocks hot enough to provide energy. The problem is that this is much deeper in some places than others, and the major economic barrier to widespread EGS development is the cost of drilling.

Heat from the rocks has to be transported to the surface by some kind of fluid to be useful for energy generation. For natural geothermal energy systems, the fluid is commonly high temperature groundwater moving upward from below. EGS injects fluid into the ground and recovers it to extract the heat. This can be accomplished by drilling two parallel boreholes as horizontal laterals through the hot rocks at depth. Engineered flowpaths are required for the introduced fluids from one well to collect heat from the deep rocks and enter the other well to be transported back to the surface.

Hydraulic fractures are created to connect the two laterals and introduce flowpaths through the hot rocks for fluids to circulate between the two wells. The vertical hydraulic fractures would be expected to intercept horizontal boreholes much more readily than vertical wells. Although this sounds easy in theory, the practice has been challenging (Ye et al. 2020). The permeability of most rocks at great depths is very low, and hydraulic fractures or some other form of permeability enhancement are needed to circulate fluids and extract heat.

One of the other challenges of EGS is the nature of the hydraulic fractures themselves. Fractures tend to have different apertures or widths where some are much narrower than others. Wider fractures are more permeable and narrow ones less so. In shale gas or tight oil production, this makes little difference because flow is from the reservoir rock into the fracture system. In EGS however, the flow is between horizontal wells via the fracture system, and the fluids will preferentially follow the wider fractures with higher permeability. This ends up extracting more heat from the rocks containing larger-aperture fractures, and less heat from rocks with narrower fractures, creating an unbalanced, inefficient system that leaves a lot of heat behind in the subsurface. Research efforts are focused on understanding the behavior of fluid movement through these induced fracture systems (Ye et al. 2020).

A potential improvement on EGS is a hybrid technology that uses solar heat to increase the temperature of marginal underground geothermal reservoirs (Zhou et al. 2013). A version of this idea called Solar-Assisted Geothermal Energy or SAGE was developed in Oman and patented in 2006. A company in the United States has licensed the process, and started field tests in 2018 on existing geothermal production wells in Nevada.

The principle behind the hybrid is to circulate solar-heated water or other fluids into a warm but not hot deep aquifer and transfer the heat to the rocks. The system uses an injection and production well like EGS, but with a solar heating component added at the surface. These are typically mirror-lined parabolic troughs with a black water pipe running through the center. The solar-heated water is injected into the ground upgradient of the production well, where it flows through the aquifer and transfers heat to the rocks. Depending on the size of the solar component, these systems can reportedly get quite hot.

Once the rocks warm up, an aquifer that was previously too cold for effective geothermal use can supply abundant hot water at efficient temperatures. The hybrid system avoids the intermittent power losses of other solar systems like photovoltaics due to night or cloudy days. More solar heat can be injected downhole during sunny periods or seasonally to build up the temperature, and the thermal inertia of the rock allows the aquifer to continuously produce hot water, day or night, rain or shine.

Advantages of the solar-geothermal hybrid include shallower wells than those required for EGS, saving on drilling costs. It can also be developed in an aquifer rock that has high porosity and permeability, thereby avoiding the need for hydraulic fracturing that will create preferential flowpaths between wells. Flow through a uniform porous medium like clean, well-sorted sandstone would be much more effective for heat exchange with the surrounding rock than flow through fractures. There are many engineering challenges to overcome, but if solar heat can be used to create geothermal groundwater in locations that previously had no geothermal resources, this could be a revolutionary source of energy.

The energy future will be a place where petroleum engineers focus on the capture and underground storage of carbon dioxide, drillers learn how to emplace geothermal wells into hot, deep rock, and geologists monitor the stability of high level nuclear waste. The only thing constant is change, and those who can adapt will do well. Those who cannot will be left behind.

12.2 Preserving Earth

It has been said that the Earth is the cradle of humanity, but one cannot remain in the cradle forever. There is no doubt that humans have been detrimental to the environment, and if we don't change our evil ways, there will be a big bill coming due soon. Humanity has become like an unemployed, middle-aged child living in our mother's basement surrounded by empty pizza boxes, crushed soda cans, and video games. We have without question trashed the place, and strained our poor old mother's ability to support us.

Some philosophers have recommended that humans should just stop breeding and quietly become extinct as a way to create a future world without human impacts where other creatures can thrive (MacCormack 2020). While this would indeed ease our impact on nature and eventually allow the Earth to heal, we won't be around to see it. Given the human obsession with sex, this probably won't happen, nor should it. The idea of restoration through extinction is nothing less than a cop-out that places an unfair burden on future generations by telling them we screwed up the planet so badly that you can't even be born. Rather than giving up and fading away, we owe it to our great-great grandchildren to fix the mess. There is no other moral answer.

Without question, uncontrolled population growth is a problem and presents a substantial burden to the environment. As societies mature technically and economically however, birth rates tend to fall, which has actually become worrisome in places like Japan. We do need to control human population, but this can be done by improving living standards around the world, not by going extinct as a species.

Rather than doing ourselves in, a better idea for clearing a substantial number of people off the Earth is for humanity to begin colonizing other worlds. Moving from our ancestral home into space will relieve pressure on the terrestrial ecosystem, allow manufacturing processes to operate off-planet without fear of damaging the environment, and let commerce and industry use free, clean, 24-h energy from sunlight.

So where do we go? Is there an Earth 2.0 someplace, a nice clean planet that hasn't been wrecked by humanity? Well, there probably is at least one of these somewhere in the galaxy, but it's not close enough to reach with current technology. Even if it was, there is the moral issue of transferring our current society with its rapacious capitalism, obsession with money, greed-driven industries, and disregard for environmental consequences to another habitable planet. If we transfer that behavior, we will just as surely destroy any new planet in a few short decades as well. Human behavior is hard to change, especially when motivated by the desire to accumulate wealth. The only real answer is to carry out these ecosystem-destroying activities someplace where there is no ecosystem to harm.

Orbiting space colonies that incorporate 1970s "high frontier" ideas (O'Neill 1977) have been a long time in coming (Gerard O'Neill himself expected them by the 1990s) but could still provide a viable habitat for humanity in space. O'Neill envisioned such habitats as long cylinders with a series of mirrors and windows to allow enough sunlight inside to grow crops, and with an axial spin to provide artificial gravity. If a colony of such habitats was positioned at one of the Lagrangian points in the Earth's orbit, it would be in a stable location with an abundant and uninterrupted supply of solar power. These habitats could be constructed at a relatively low cost if they were built in space using materials manufactured in space, perhaps on the moon or mined from asteroids.

An asteroid called 16 Psyche with a diameter of about 140 miles (226 km) orbits between Mars and Jupiter. Psyche is metallic rather than rocky, and may be the remainder of the core of a former protoplanet. It is said to contain up to $700 quintillion in usable metals at current prices. This is far more metal than has been mined on Earth throughout the whole of human history. To understand just how much wealth $700 quintillion is, if divided equally among every human being now living on the planet, each person would receive $93 billion. Of course, once we are awash in gold, silver and platinum, these metals will be cheaper than steel. NASA plans to send an unmanned satellite to 16 Psyche in 2026 to explore and analyze the chemistry of the asteroid (source: NASA websites).

O'Neill's vision for the income to build his space colonies was to orbit a series of solar power satellites that would use microwaves to beam power down to receiver stations on Earth, thus also solving the fossil energy problem at the same time. From a climate change perspective, which was not on the proverbial radar screen in

O'Neill's day, there could be an issue with microwaves passing through the atmosphere. Water vapor absorbs microwave frequencies just as methane and carbon dioxide absorb infrared. In fact, a microwave oven works because the water in food absorbs the microwaves and heats up. Passing a strong beam of microwaves from a power satellite through the atmosphere will heat any water vapor it encounters, creating atmospheric warming and causing climate disruptions. It is more likely that income from space resource extraction and off-Earth manufacturing would provide more than enough wealth to support both orbiting space colonies and permanent settlements on the moon and Mars.

Would people be willing to live in such places? Past experience suggests that if jobs and opportunities were available, the answer is yes. Most colonization efforts of the past were driven by economic incentives. Pioneers put up with Alaskan cold, Arizona heat, Dakota blizzards, Honduran mosquitos, Amazonian humidity, and the thin air of the high Andes to colonize these places and make their fortunes. A climate-controlled space habitat or underground lunar base would be quite comfortable by comparison.

Human migrations throughout history have occurred because of overcrowding or a lack of opportunities at home. Relocating to a new land promised more space and the ability to set one's own destiny. The attraction of resources, wealth, self-determination, and a chance at a better life brought colonists into the Americas from all over the world on rickety wooden sailing ships. They endured ocean voyages that were far longer and much more dangerous than the lunar transit being contemplated by the engineers currently developing commercial spacecraft for trips to the moon.

One of the complications with mass migrations on Earth, of course, is that the odds were pretty good that somebody was already living in your so-called "New World," and they were willing to defend their land and homes with force if necessary. This led to many deaths and some very sad history in North and South America, the Caribbean, Africa, Australia, New Zealand, India, Pakistan, China, and Hawaii, among other places. None of the other planets, moons, and asteroids in our own solar system appears to have any inhabitants on them as far as we know. Even if we do find life someplace like the subsurface of Mars or in the oceans of Europa, there is still plenty of unoccupied real estate orbiting the sun. For once in our sad and sordid history, humans can colonize a new land without having to decimate the natives first.

Besides helping to preserve the Earth, there are substantial economic benefits to be had in space. Moving the industrial base of humanity to the moon, for example, would allow manufacturers to produce goods using solar energy and raw materials available either on the moon itself, or shipped in from the asteroid belt. Resources that are already in space are abundant and easy to move around compared to those that have to be lifted out of the Earth's deep gravity well. There is no lunar ecosystem to destroy, and heavy industry on the moon or in orbit could include mining and refining asteroid materials and manufacturing useful products from them. It can be done without causing any harm whatsoever to the landscapes, streams, groundwater, air, or ecosystems of Earth.

Transferring operations from the Earth into space that involve energy production, mining, minerals processing, materials refining, chemical manufacturing, smelting, metal plating, and other pollution-intensive heavy industries is one way to keep human civilization moving ahead technologically, without sacrificing the environment in the process. Earth could become a park-like world, with large nature preserves, clean cities, and jobs that have a low-impact on the environment. How is that for a vision?

12.3 Recommendations

So where does this leave us? There is a lot of information to digest in terms of fossil energy, fracking, and the environment. Fracking does indeed have some environmental issues, but most of these are no better or worse than any other form of fossil fuel extraction and use. The point is that ALL forms of fossil fuel extraction and use are bad for the environment. We must, as responsible stewards of this planet, use fossil fuels for no more than another decade or two at most to maintain the technological level of our civilization high enough to develop more sustainable, less impactful forms of energy. If we fail to do so, all of humanity will suffer the consequences. In fact, the entire ecosystem of the planet may suffer the consequences.

This book has attempted to lay out in a logical, understandable manner the issues we are facing and the steps that must be taken. We must use the technology we have on hand, and not sit idly by waiting for a miracle of hot or cold fusion, zero point energy, harnessing a black hole, or some other exotic energy source to solve our problems. We have the technology available to do this. It requires the political will to implement it. It must be done in a methodical, logical manner to minimize disruption, but we must move forward.

The recommendations below are from a geologist who has spent a 45-year career working on issues related to energy, water, and the environment. I have a lot of experience with these issues, and maybe I'd be classified as an "expert." But there are a lot of other people, many of whom are much smarter than I am that have been thinking about this. Everyone needs to come together and work together to solve this problem. We need ideas, but more importantly, we need the will to implement these ideas. And we can't put it off much longer. As Theoprastus (371-286 BCE), Aristotle's student and the founder of botany once noted, "Waste of time is the most extravagant of all expenses."

It was stated earlier that energy use is controlled by three factors: technology, economics, and policy. The technology is out there and continually improving. But the economics of established energy giants like big oil, cheap coal, and abundant natural gas are difficult to overcome. Renewables are more expensive, period. Despite 40 years of technological improvements to wind, solar, and geothermal, they are still only marginally cost-competitive with fossil fuel. New nuclear is almost not even on the table. So we have the technology, and we have done all we can with the economics. All that is left is policy.

The ten recommendations given below have been discussed throughout the text. They are brought together in this final section to consolidate an approach for dealing with fracking, fossil fuel, renewable and sustainable energy, and climate disruption. Implementing these recommendations and others like them will require a policy commitment from the highest levels of government. If we attempt to rely on technology and economics alone to resolve the energy issues in the United States and the world, we will fail. Period. If we do even less and continue with business as usual, we will be going off a cliff in a few short decades. It is the responsibility of every thinking voter in every nation to select political leaders at every level who will recognize the danger, acknowledge the problems, and who are willing to stand up to political lobbyists, big business, and deeply established ways of doing things in our economy to make a change.

Fracking Has Some Risks, But Many of These Are Overblown Fracking does not appear to pose any greater risk to the environment than other forms of fossil fuel extraction, and in fact it is far less risky than Arctic drilling, deepwater offshore oil production, or mountaintop removal coal mining. Fracking is nothing more than a completion technology and people need to stop conflating it with all forms of oil and gas production. There is no distinction between “fracked gas” and any other source of natural gas, and labeling it as a particular kind of evil is a disservice to the larger overall discussion that we need to be having about sustainable forms of energy. Fracking technology is constantly advancing into better economics and greater efficiency. The energy industry should be encouraged with incentives and tax breaks to use greener chemicals and safer techniques, and reduce emissions. Violations that lead to environmental contamination should be met with steep fines and bans on production in a state. Fees for drilling permits should be raised steeply to fund a robust and ever-watchful regulatory agency to keep operators on the straight and narrow.

Banning Fracking Is a Bad Idea We desperately need natural gas as a bridge fuel to get us away from the far more polluting use of coal and into more sustainable forms of energy production. Seventy percent of our domestic natural gas is now produced from fracked wells. A fracking ban will not stop GHG production; in fact it will make it worse because the resulting shortages of natural gas will likely be replaced by coal, which produces twice as much CO_2 per Btu of energy than natural gas. Shortages of domestic petroleum will be made up by importing oil, with all of the geopolitical risks that entails. Environmentalist fantasies about fracking bans leading to the replacement of fossil fuels with wind and solar power are unlikely because these overlook the economics and require utilities to abandon billions of dollars worth of existing infrastructure.

The Transition to Sustainable Energy Must Be Gradual and Measured It can start by replacing the heat sources in thermal power plants that boil water to make steam for turning turbines and running generators. The huge capital expense of simply abandoning this existing electrical infrastructure in favor of solar farms and wind turbines is not acceptable to investor-owned electrical utilities. Non-GHG emitting heat sources, such as solar-assisted geothermal and new-technology nuclear (and probably others) can directly replace coal burners or natural gas combined cycle turbines, allowing existing power generating infrastructure to be maintained. What is needed is a source of heat to boil water and make steam. It makes no difference to the boiler if that heat comes from coal, gas, nuclear, or geothermal. The transition to sustainable energy must happen and it must happen soon. Getting this started on existing electrical infrastructure is a gradual and minimally-disruptive way to begin the process.

The Nuclear Waste Problem Must Be Resolved Desperately needed advances in new nuclear technology have been stymied by the waste problem. Nuclear waste from reactors, even new technology thorium-seeded reactors, must be handled in a responsible manner. Leaving this waste stored in dry casks at existing nuclear power plants near major cities is a significant risk. During the Cold War, the Soviets knew that the best way to enhance the fallout cloud was not to bomb the city, but to bomb the nearby nuclear power plant. Although the Cold War is behind us, this risk still exists for any of the multitude of terrorist groups seeking to acquire nuclear devices. The proposed nuclear waste repository at Yucca Mountain in Nevada is located in remote desert a hundred miles (160 km) from the nearest big city. There is nothing technically wrong with Yucca Mountain. Years of studies and billions of dollars in research have failed to find any fatal technical flaws in using the site for the storage of high-level nuclear waste. Given the investments that have already been made in time and money, this site should be reconsidered. All the existing problems are political in nature, and will require careful negotiations, engaging stakeholders, possibly a new government agency to be in charge, creative thinking, and probably some money to resolve. Resolve it we must, if we are to move forward with nuclear technology.

New Nuclear Technology Should Be Robustly Pursued Thorium-seeded molten salt reactors are small, safe, cannot melt down in a loss of cooling accident, and use thorium as the fertile element to create $_{230}$U, a light, fissionable isotope of uranium that does not pick up neutrons and create the dangerous “transuranics” like plutonium that are produced as waste products in standard enriched-uranium reactors. Other advanced technologies should also be investigated and developed. Current reactor technology is a byproduct of nuclear weapons production from the Cold War, and it is high time it was left behind as old school and new technology implemented. Molten salt reactors are small enough to be installed in existing fossil fuel power plants as a replacement heat source to make steam. The abundance of thorium and the potential for reprocessing spent fuel for re-use makes this technology pretty close to “sustainable,” and it produces zero GHG in operation.

Government Research on Energy Should Focus on Geothermal So called “clean coal” and other fossil fuel technologies ought to be abandoned to the dust bin of history and much more attention given to two new geothermal technologies that show promise but need development. These are Enhanced Geothermal Systems (EGS) and Solar-Assisted Geothermal Energy (SAGE). EGS seeks to drill parallel wells into the hot rocks located at great depths everywhere on Earth, and then create flowpaths between them using fracking to allow circulating fluids to bring up heat from below. A pilot project in Utah is in the early stages. SAGE places wells into shallower aquifers and uses solar heat to increase the temperature of the subsurface, extracting it as needed. Both of these have the enormous advantage of working nearly anywhere on the planet without the requirement for hot springs, geysers, volcanic vents, etc. Tests of the technologies are underway but improvement and commercialization is needed as quickly as possible. The application of government and national lab expertise on drilling, geosciences, subsurface engineering and other related fields could help either of these replace fossil fuel heat sources in power plants fairly soon.

Fossil Fuel Vehicles Should Be Replaced Electric vehicles are well developed if expensive – these are seeing continual improvements with the promise of a battery that will last a million miles. However, an electric vehicle has little to no environmental benefit if it is charged up using coal-fired electricity, which is why the changes to power plants must happen in tandem. Other options for non-GHG emitting vehicles include hydrogen powered cars, either by direct combustion of hydrogen or through the use of hydrogen fuel cells to generate electricity. Most commercial hydrogen is currently derived from natural gas (known as "blue hydrogen"), but non-GHG hydrogen can be produced through an electrolytic process using solar or wind electricity (called "green hydrogen"), or through a thermolysis process using waste heat from nuclear reactors. These technologies are currently cumbersome, expensive, and inefficient, and significant development will be needed for widespread commercialization. Policy incentives and government research support can help move them forward.

We Must De-incentivize the Use of Fossil Fuel The simplest and most straightforward way to do this from a policy perspective is to impose a carbon tax on GHG emissions. A carbon tax must be steep enough that any industry considering burning coal will find it more cost effective to capture the CO_2 emissions and sequester them from the atmosphere rather than pay the tax, or switch to an alternative energy source like geothermal or nuclear that produces zero emissions and is therefore not taxed. Non-combustion uses of petroleum, such as plastics manufacture, would not be subjected to the tax. The tax should be scaled to the emissions of GHG per Btu of energy, thereby making the worst offender (coal) the most expensive, and the least offender (natural gas) cheaper. However, since methane is also a GHG, leaks in the natural gas production, transmission, and distribution system should also be taxed, providing companies with an incentive to fix these. GHG-emitting vehicles including automobiles, ships and jet aircraft should also be subject to a carbon tax. This will provide incentives for alternative fuels, biofuels, or electric vehicles and encourage conservation. In addition, all government tax breaks and incentives for the production of petroleum, natural gas, and coal should be rescinded. In the U.S. these date back to the oil embargo and are no longer sustainable or necessary. Externalized costs such as the restoration of strip-mined lands, the remediation of impaired streams from acid mine drainage, and the proper plugging of abandoned wells should be returned to the industry. If the industry refuses to cooperate, these costs can be included in the carbon tax on their products, further de-incentivizing production. Funding from a carbon tax should be used to remove CO_2 from the atmosphere with Direct Air Capture systems.

We Must Repair Our Atmosphere and Environment All GHG emissions from fossil fuel combustion should be captured as immediately as possible. This includes both stationary sources like power plants, and mobile sources like automobiles. Technology for CCS from stationary sources is available, but improvements in efficiency are needed. Technology for mobile sources exists, but has yet to be implemented. Converting automobiles from gasoline to compressed natural gas will have a cost-saving incentive under this policy because CNG emits less CO_2, resulting in a lower carbon tax on emissions or a longer life for whatever CCS system is in place. Direct air capture should be implemented around the world as quickly as possible. It can include planting trees, fertilizing the oceans to encourage algal blooms, and using mechanical systems that remove and sequester CO_2 in locations like deserts or tundra that are unfavorable for plant life. Storage of captured CO_2 in solid form as calcium carbonate (the mineral calcite) avoids problems with the gas leaking out of a storage formation and re-entering the atmosphere. The goal must be to reduce and maintain CO_2 levels in the atmosphere at 300 ppm or less. This is the maximum concentration reached between Ice Ages and the level in the atmosphere prior to the start of the Industrial Revolution (refer back to Fig. 9.3). Sadly, with the climate changes already set in motion this will help to mitigate climate disruptions but will not eliminate them.

We Must Become a Multi-planet Species If we learned anything at all from the OPEC oil embargo, it is that having all of our eggs in one basket is not a good idea. In addition to climate disruptions, human civilization is at risk from asteroid impacts, solar flares and coronal mass ejections from the sun, supervolcano eruptions, pandemics, and that old standby, accidental or deliberate nuclear war. Getting a significant portion of our population off this planet and onto the moon, Mars, or orbiting space colonies gives us a better chance for long-term survival as a species. Moving our industrial base off Earth and into space will relieve pressure on the fragile ecosystems of our planet, allowing them an opportunity to recover. There are no ecosystems in space to damage, so manufacturing can proceed apace with abundant free energy from continuous sunlight and abundant raw materials easily moved around from one low gravity environment to another. Robust industries in space and on the moon will provide millions of job opportunities and incentives for people to migrate from Earth to a literal “new world” with the added bonus of not colonizing some indigenous person’s home in the process.

****

The issue of fracking and the environment, or perhaps the larger issue of fossil energy and the environment has reached the point where decisions must be made. Banning fracking is not the answer, because that isn't the problem. Fossil energy is the problem, and we have to move away from it into cleaner, more sustainable energy. Natural gas from fracking can help with the transition, but the transition must be made. Leadership from the top is essential.

If we wish to maintain a technological civilization, we need a carbon tax to make fossil fuel more expensive, renewables more competitive, and provide a revenue stream for CCS and DAC. Major research efforts should be focused on developing the technology for EGS, SAGE, and new, safer and smaller nuclear designs that can directly replace the burners in coal-fired and gas-fired power plants. The problem of what to do with nuclear waste must be solved, at Yucca Mountain if possible given the already huge investment, but if not there, somewhere.

If we continue with business as usual on the path we are following, within 50 years, or a century at the outside, we will have crossed a tipping point where the habitability of the Earth for humanity and many other species may be questionable. If we don't solve the problems with fossil fuels and sustainable energy, the Earth will solve it for us, most likely by driving us extinct as a species. A million years from now, some creature will be looking at our fossilized remains in the rocks of the Anthropocene and wondering how and why we let ourselves become extinct. A high third quarter return on investment is not a good answer.

References

Bennett, B., Repacholi, M., & Carr, Z. (Eds.). (2006). *Heath effects of the Chernobyl accident and special health care programmes: Report of the UN Chernobyl forum expert group "health"* (167 p). Geneva: World Health Organization.

Day, W. C., Potter, C. J., Sweetkind, D. S., Dickerson, R. P., & San Juan, C. A. (1998). *Bedrock geologic map of the central block area, Yucca Mountain, Nye County*, Nevada: U.S. Geological Survey IMAP 2601; two sheets plus pamphlet. https://doi.org/10.3133/i2601

Easterling, D., & Kunreuther, H. (1995). *The Dilemma of siting a high-level nuclear waste repository*. New York: Springer. 286 p.

Hamilton, L. H., & Scowcroft, B. (2012). *Blue ribbon commission on America's nuclear future*. Final report to U.S. Secretary of Energy, U.S. Department of Energy, Washington, DC, 157 p. http://brc.gov

IAEA (International Atomic Energy Agency). (2005). *Thorium fuel cycle – Potential benefits and challenges: Report IAEA-TECDOC-1450*. Vienna: International Atomic Energy Agency. 113 p.

Kramer, D. (2020). Negative carbon dioxide emissions. *Physics Today, 73*(1), 45–51.

MacCormack, P. (2020). *The Ahuman manifesto: Activism for the end of the Anthropocene*. London: Bloomsbury Academic. 224 p.

Markandya, A., & Wilkinson, P. (2007). Electricity generation and health. *The Lancet, 370*(9591), 979–990.

O'Neill, G. K. (1977). *The high frontier: Human colonies in space* (1st ed.). New York: William Morrow and Company. 288 p. (ISBN 0-688-03133-1).

Paces, J. B., Neymark, L. A., Marshall, B. D., Whelan, J. F., & Peterman, Z. E. (2001). *Ages and origins of calcite and opal in the exploratory studies facility tunnel, Yucca Mountain, Nevada*. U.S. Geological Survey Water-Resources Investigations Report 2001-4049, 95 p.

USDOE. (2016). *What is an Enhanced Geothermal System (EGS)?* Fact Sheet DOE/EE-0785, DOE Office of Energy Efficiency & Renewable Energy, Geothermal Technologies Office, 2 p. https://www.energy.gov/eere/geothermal/downloads/enhanced-geothermal-system-egs-fact-sheet

Wang, T. (2019). Number of operable nuclear reactor plants by country 2019. *Statista*. https://www.statista.com/statistics/267158/number-of-nuclear-reactors-in-operation-by-country/. Accessed 20 Mar 2020.

WHO (World Health Organization). (2013). *Health risk assessment from the nuclear accident after the 2011 Great East Japan Earthquake and Tsunami based on a preliminary dose estimation*. Geneva, Switzerland: World Health Organization. 172 p.

Ye, Z., Ghassemi, A., & Kneafsey, T., (2020). Deformation, Failure and Permeability Evolution of Sealed Fractures in EGS Collab Poorman Schist. In *45th Workshop on Geothermal Reservoir Engineering*, Stanford University, Palo Alto, California, February 2020.

Zhou, C., Doroodchi, E., & Moghtaderi, B. (2013). An in-depth assessment of hybrid solar–geothermal power generation. *Energy Conversion and Management, 74*, 88–101.

Appendices

Appendix A: Acronyms and Glossary

A	Cross sectional area term in Darcy's Law
AAPG	American Association of Petroleum Geologists (professional society)
API	American Petroleum Institute: Industry trade and standards-setting organization founded in 1919 to establish consensus standards for the oil and gas industry.
Associated gas	Natural gas that occurs with petroleum in a reservoir, either as a separate phase occupying pore space above the oil, or as a solution phase within the oil itself.
Blooey line	A diversion pipe to a storage tank for fluids initially returned from a well after a completion. Gas from the blooey line is usually flared.
Breakdown pressure	Pressure at which rock strength is overcome and a hydraulic fracture is initiated.
BOP	Blow-out preventer: Hydraulic jaws and ram on the wellhead designed to close off the well in event of a blow-out.
Bottomhole assembly	Downhole impeller, mud motor, cutting bit, steering, and navigational equipment used for directional drilling
Btu	British thermal unit; a measure of energy equivalent to about 250 calories; a cubic foot of natural gas contains about 1000 Btu.
Cable tool rig	Old-style drill rig that used a bit mounted to a lift-and-drop cable arrangement to pound a hole in the ground by percussion. Largely replaced by rotary rigs, but a few are still in use for small drilling operations.
Carbonatation	A carbon dioxide capture process that uses calcium hydroxide. There is a similar process employing sodium hydroxide.
Casing	Protective liner, usually steel pipe, installed and cemented in a well to seal off different zones; each diameter is called a "string."
CCCM	The climate change counter-movement – Organized opposition to climate change that attempts to sow confusion, doubt and uncertainty about the science.

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2

CCS	Carbon capture and storage: Technology to prevent carbon dioxide GHG from fossil fuel combustion from entering the atmosphere.
CDC	Centers for Disease Control, U.S. National Health Service
Christmas tree	Oilfield slang for the production wellhead installed on a gas well.
Conductor casing	The shallowest casing string, usually a few meters of corrugated steel pipe buried vertically on the well pad to hold back soil and electrically ground the rig.
Consumptive use	Water that is removed from a watershed and not returned as runoff or wastewater. Sometimes called an "out-of-basin" transfer.
Continuous resource	USGS term for an unconventional O&G resource like a shale that can be produced for just about anywhere in the formation as long as the proper stimulation techniques are applied.
Conventional	An oil or gas resource trapped structurally or stratigraphically in a permeable rock that can be produced with a vertical well and a simple completion.
CTL	Coal-to-liquids; a synthetic liquid fuel manufactured through the Fischer-Tropsch catalytic process; never became cost-competitive with petroleum-based fuels.
CWT	Centralized wastewater treatment plant - generally a privately-owned facility set up for treating industrial wastewater for surface disposal.
DAC	Direct air capture - the removal of carbon dioxide and other GHG directly from the atmosphere, rather than by capturing it on a smoke stack.
Darcy	Empirical permeability unit named after Henry Darcy; metric: 1 darcy = 10^{-12} m^2
DBPs	Disinfection byproducts: Halogenated compounds formed when brominated or chlorinated organics react with chlorine during drinking water disinfection.
DCA	Decline Curve Analysis: A specialized field in petroleum engineering that uses the shapes of decline curves to forecast the performance of oil and gas wells.
ΔP	"Delta P" term for differential pressure in Darcy's Law
DOE	Department of Energy (U.S. government)
DOI	Department of the Interior (U.S. government)
Downstream	O&G industry term for the part of the business focused on the distribution and sale of refined products or fuels (see midstream and upstream)
Drilling mud	A complex fluid mix used to cool the bit, remove cuttings, maintain borehole stability, and supply hydraulic power to a downhole motor.
DPM	Diesel particulate matter – Carbon soot with a coating of metals or organics
E-frack	A non-diesel frack operation that uses electric pumps powered by an on-site turbine generator fueled by natural gas from nearby wells.
EGSP	Eastern Gas Shales Project: A 1980s DOE shale gas assessment in the Appalachian, Michigan, and Illinois basins.
EOR	Enhanced oil recovery, usually a waterflood to produce more oil.
EPA	Environmental Protection Agency (U.S. government)
Externalized cost	Environmental costs of a extracting and using an energy resource that are covered by taxpayers rather than industry, such as stream restoration.
Fault	A natural fracture in rock where the two sides have slid past one another.
Flambeau	An old term for a gas well flare used to prove that the well was flowing. These wasted significant amounts of gas.

Flare	Burning off associated natural gas during the initial stages of flowback, or longer-term to recover easily-transported hydrocarbon liquids
Flowback	The initial liquid and gas returns after a well is fracked. Brine recovered after the well is put on production is known as "produced water."
Frack	Slang term for "hydraulic fracturing;" the oil & gas industry typically spells it "frac" without the k.
Frack gate	A massive, heavy-duty, temporary wellhead designed to control the movement of fluids in and out of a well during hydraulic fracturing operations.
Fugitive emissions	Produced natural gas leaking into the air from faulty seals or bad connections on surface infrastructure (see stray gas)
Ga	Giga-annum; geologic abbreviation for one billion years of time.
Gazprom	The Russian state-owned natural gas production, transmission and distribution company.
GDP	Gross Domestic Product: Annual output of goods and services; an economic indicator
Geosteering	The art and science of guiding a bottomhole assembly to drill a borehole in a precise location
GHG	Greenhouse gas - gases like carbon dioxide and methane that absorb infrared radiation and trap heat in the atmosphere
GIP	Gas in place
Gw	Gigawatt: One billion watts of electricity; a thousand Mw
Halliburton loophole	A provision of the 2005 Energy Policy Act that exempts frack service companies from compliance with the UIC requirements of the Safe Drinking Water Act.
Heel	The near end of the lateral where the well begins to curve upward into the tophole
HEI	Health Effects Institute (Boston, Mass.)
HVHF	High-volume hydraulic fracturing used on shale gas and tight oil resources.
IDF	Israel Defense Forces: The Israeli army, navy, and air force.
IEA	International Energy Agency (based in Paris, France)
Independent	A medium sized oil and gas exploration and production company (see "major")
Intermediate casing	A casing string set below the surface casing to a depth of about a kilometer (3000 ft) to keep gases and fluids from shallower formations out of the well.
IP	Initial production; the maximum flow rate at which gas and liquids are produced from a well immediately after completion.
IPCC	Intergovernmental Panel on Climate Change – A U.N. sanctioned body investigating human effects on climate
IR	Infrared radiation – Electromagnetic energy wavelengths longer than the red end of the visible spectrum that transfer heat.
Joint (drilling)	A single, 30 ft. (10 m) length of drill pipe or casing.
Joint (geologic)	A natural fracture in rock where the two sides have moved apart, usually caused by compression
Jökulhlaup	Icelandic term for a rush of meltwater released by a glacial flood, such as the catastrophic failure of an ice dam or a volcanic eruption under a glacier.
K	Permeability or hydraulic conductivity term in Darcy's Law

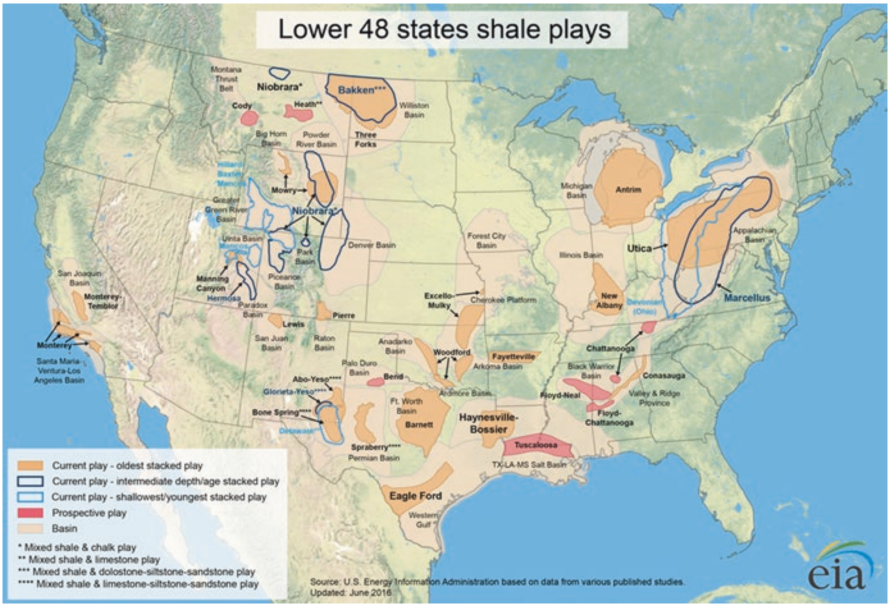
Kerogen	Naturally occurring, solid organic matter, not soluble in organic solvents, generates hydrocarbons when heated
Kerosene	A clean-burning lamp oil refined from petroleum by Dr. Abraham Gesner and named from the Greek words for “wax” and “oil.”
Kickoff point	Location in the vertical tophole where a well begins to turn horizontal.
Kw	Kilowatt: One thousand watts of electrical energy; a kilowatt-hour is a metered quantity of electricity
L	Length term in Darcy’s Law
Lateral	Horizontal borehole used to produce hydrocarbons from shale
Leak-off	Migration of frack fluid into the formation
Light sand frack	A hydraulic fracturing technique that uses less proppant sand in induced fractures and is more economical.
LNG	Liquefied natural gas; a cryogenic liquid consisting of mostly methane with a trace of ethane cooled to −256 deg. F (−159 deg. C) taking up 600 times less space.
LTO	Light tight oil: Low viscosity, high volatility, high API gravity (>40) petroleum from shales and other tight rocks.
LWD	Logging while drilling – Gathering data and sending information back to the surface while directional drilling to inform the rig crew about rock properties.
Ma	Mega-annum; geological abbreviation for one million years of time.
MAD	Mile-A-Day: A term for ultra-fast drilling that achieves extreme rates of penetration.
Major	Gigantic, multi-national, oil and gas exploration, production, processing, and marketing corporations (see “independent”)
MCF	Thousand cubic feet of gas (from the Roman numeral “M”); metric equivalent: 1 MCF = 28.3 cubic meters
Md	Millidarcy; a permeability unit of one thousandth of a darcy
μd	Microdarcy; a permeability unit of one millionth of a darcy
METC	Morgantown Energy Technology Center – predecessor to NETL
Midstream	O&G industry term for the part of the business focused on moving oil and gas from production areas to markets. (see downstream and upstream)
MMBtu	Million British thermal units. A thousand cubic feet of natural gas (MCF) is approximately equivalent to 1 MMBtu.
MMcf	Million cubic feet of gas. 1 MMCF = 28,320 cubic meters
MMcf/d	A production number of a million cubic feet of gas per day
MOX	Mixed-oxide fuel rod for a nuclear reactor, typically uranium and plutonium.
MPa	Mega Pascal; metric unit of pressure equivalent to 1000 kPa (kiloPascals)
MTR	Mountain top removal mining method that strips overburden off coal seams on plateaus and dumps it into adjacent watersheds. Common in Appalachia.
μ	Mu - viscosity term in Darcy’s Law
Mw	Megawatt: One million watts of electricity; a thousand Kw
MWD	Measurement while drilling; see “geosteering”
NA	Natural attenuation – the natural microbial and geochemical reactions in an aquifer that break down organic contaminants
Nd	Nanodarcy; a permeability unit of one billionth of a darcy

NDA	Non-disclosure agreement, often required by the O&G industry in return for compensation for damages.
NETL	National Energy Technology Laboratory of the U.S. Department of Energy
NGL	Natural gas liquids – heavier hydrocarbons produced as vapor that condenses to liquid at the surface; also known as “condensate”
NGO	Non-government organization, usually refers to a non-profit institute
Non-associated gas	Natural gas that occurs without petroleum. Coalbed methane is an example.
NORM	Naturally-occurring radioactive material.
NOx	Nitrous oxides, a combustion product of most fossil fuels
NPDES	National Pollutant Discharge Elimination System (EPA stormwater permit)
O&G	Oil and gas; refers to both the resource and the industry
OPEC	Organization of Petroleum Exporting Countries (an oil cartel)
Open-hole	A well completed with surface casing only and no intermediate casing.
P&A	Plug and abandon: a regulatory procedure for properly sealing a non-producing well with bridge plugs and cement to protect the environment.
PAC	Political Action Committee
PADEP	Pennsylvania Department of Environmental Protection (state agency)
Pancaking	Oilfield slang when a shallow hydraulic fracture breaks horizontally instead of vertically because of insufficient overburden stress.
PE	Licensed Professional Engineer
Perf gun	A carrier with a series of high explosive charges and a remote detonator used to create holes (perforations) in production casing.
PEMEX	A contraction for *Petróleos Mexicanos*, the national oil company of Mexico
PETM	Paleocene-Eocene Thermal Maximum: A period beginning about 56 Ma when GHG levels rose steeply, warming the Earth by up to 8 °C.
Petrobras	Contraction for *Petróleo Brasileiro S.A.*, the national oil company of Brazil.
pC/l	Pico Curie per liter – A human health measurement for radioactive materials like radium in water (5 pC/l limit) or radon gas in air (4 pC/l limit).
PG	Professional Geologist licensed by the National Association of State Boards of Geology (ASBOG)
PM	Particulate matter, often designated as $PM_{2.5}$ (2.5 microns; smoke) or PM_{10} (10 microns; dust)
Polymorph	A mineral with an identical composition that occurs in different crystal structures, i.e. graphite and diamond are polymorphs of carbon.
POTW	Publicly-owned treatment works: The EPA designation for a municipal wastewater treatment plant.
Produced water	Fracking flowback and formation water produced with hydrocarbons from an O&G well. Produced water must be disposed of or recycled.
Production casing	The narrowest casing string in a well, run from the production zone to the surface.
Proppant	Sand or ceramic beads added to frack fluid to prop hydraulic fractures open after the stimulation is completed and pressure is released.
Q	Discharge or flow term in Darcy’s Law
RCRA	Resource Conservation and Recovery Act
Reservoir stimulation	The process of engineering a completion to improve hydrocarbon recovery from a reservoir; includes both hydraulic fracturing and matrix stimulation.

Residual waste	Non-hazardous waste produced by industrial processes, distinct from municipal waste.
RGGI	Regional Greenhouse Gas Initiative
RIS	Reservoir-induced seismicity; earthquakes caused by filling a reservoir behind a large dam.
ROI	Return on investment; payback rate of an oil or gas well based on production.
ROP	Rate of penetration: Drilling rate.
Rosneft	Russia's largest oil company, a contraction for *Rossiyskaya neft* or "Russian oil."
Service company	An O&G production company that specializes in "completion" work after drilling but before production, such as cementing, well logging, and fracking.
Slickwater	Frack water treated with polyacrylamide to reduce downhole friction losses
Social license	Operator actions and planning prior to shale development that seeks to ensure local citizens see value in the activity and are not angered over it.
Sour gas	Natural gas containing hydrogen sulfide (H_2S) that cannot be sold into a pipeline without cleanup.
Source rock	An organic rich, fine grained rock that generated hydrocarbons internally during the burial and lithification process.
SPE	Society of Petroleum Engineers (professional society)
Spud	The act of beginning to drill (sometimes "spud-in"). The spud is when a drillbit starts making a hole from the surface.
Stranded gas	Natural gas resources in locations without a pipeline to carry them to market.
Stray gas	Natural gas in groundwater either generated in-situ, or migrated in by a number of different pathways from geologic formations or uncased wells.
String	A length of uniform diameter casing in a borehole. Casing strings to greater depths must be narrower to fit inside shallow casing. Also refers to a length of drill pipe.
Surface casing	The uppermost casing string run from the surface to a depth of several hundred feet in a borehole to protect drinking water aquifers.
TCF	Trillion cubic feet of gas; 1 TCF = 28.3 billion cubic meters
TDS	Total dissolved solids: The amount of inorganic material dissolved in water
TE-NORM	Technologically-Enhanced NORM; A technology process like fracking that produces NORM where it would not be present otherwise.
Tight rocks	A term for low-permeability rocks like shale, coal, and certain limestones and sandstones.
TOC	Total organic carbon
Toe	The far end of a lateral where drilling terminates and the first frack stage begins.
Tophole	The vertical part of a shale gas well above the lateral
Town gas	A manufactured cooking and lighting gas created by heating coal and water in the absence of air, resulting in combustible hydrogen and carbon monoxide gases.
TRRC	Texas Rail Road Commission: The state agency that issues permits for oil and gas well drilling in that state.
UIC	Underground Injection Control: a disposal well regulated by the EPA. Class II wells are designated for oilfield wastes.
Unconventional	An oil or gas resource that is continuous in a source rock and requires reservoir stimulation like fracking to produce.

Upstream	O&G industry term for the part of the business focused on the drilling and extraction of oil and gas from the ground. (see midstream and downstream)
USEIA	U.S. Energy Information Administration (U.S. government)
USDW	Underground Sources of Drinking Water – The USEPA name for a freshwater, shallow aquifer.
USGS	United States Geological Survey, a government Earth science agency and a bureau of the U.S. Department of the interior
VOCs	Volatile organic compounds that can create air pollution.
Water cut	The ratio of water to the total produced fluids brought to the surface in an O&G production well. Higher water cuts incur greater disposal costs.
Wings	Vertical hydraulic fractures that extend from either side of a vertical well up to 300 m (1000 ft) in the direction of maximum compressive stress

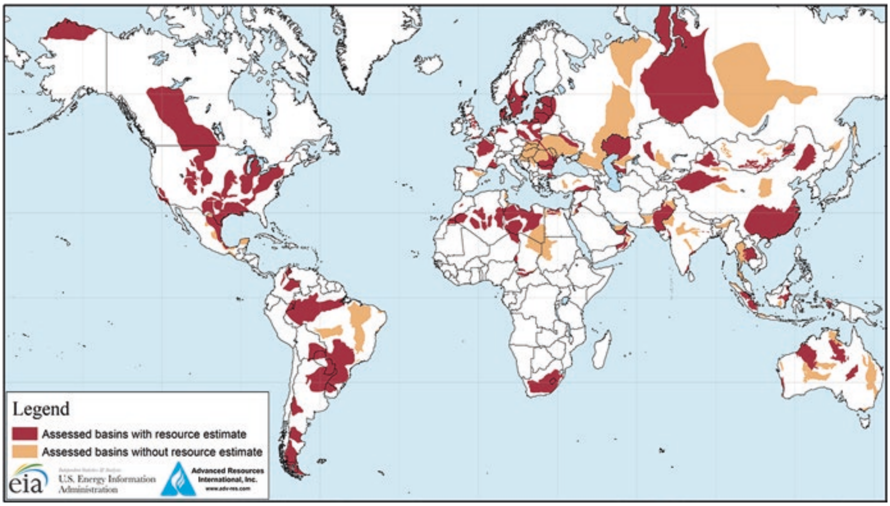
Appendix B: Shale Resources of the United States



Source: U.S. Energy Information Administration based on data from various published studies.
Updated: June 2016

Shale gas and tight oil plays in the contiguous U.S

Appendix C: Shale Resources World-Wide



World-wide sedimentary basins containing assessed or suspected tight oil and/or shale gas resources. (Source: U.S. Energy Information Administration and Advanced Resources International)

Index

D. J. Soeder, *Fracking and the Environment*,
https://doi.org/10.1007/978-3-030-59121-2