Zimmerman & Associates

Environmental Litigation, Mediation, Enforcement & Compliance, Counseling

February 27, 2013

U.S. Department of Energy (FE–34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
P.O. Box 44375
Washington, DC 20026-4375

LNGStudy@hq.doe.gov.

Re: 2012 LNG Export Study – Oversized Document in Support Of Rebuttal Comments

Dear Sirs:

On behalf of Damascus Citizens for Sustainability, Inc. and NYH20, Inc., we submitted rebuttal comments on the 2012 LNG Export Study by NERA Consulting by letter dated February 25, 2013. These rebuttal comments were submitted by email prior to the 4:30 p.m. EST comment deadline. Attached to this comment letter were two documents. A third document could not be submitted by email because it was too large a file to be transmitted by our internet service provider. We only learned this when we received an email from the service provider informing us that the file could not be sent to you due to its size. One of the two documents that were attached to our comments was an executive summary of this third document and we incorporated a quotation from this executive summary in our comment letter. In order to assure that you have the full report, we contacted Mr. John Anderson, the individual listed as the point of contact in the Federal Register notice, and after checking with his legal counsel, he requested that we deliver the document on a compact disk and include this letter to explain why this document is being submitted after the comment deadline.

If you have any questions about this matter, please contact me at your convenience.

Sincerely,

/s/ J.J. Zimmerman

Jeff Zimmerman
counsel for Damascus Citizens for
Sustainability and NYH2O

Attachment on disk

13508 Maidstone Lane, Potomac, MD 20854 (240) 912- 6685 (office); (301) 963-9664 (fax)

DRILL, BABY, DRILL

CAN UNCONVENTIONAL FUELS USHER IN A NEW ERA OF ENERGY ABUNDANCE?

BY J. DAVID HUGHES

FEB 2013

POST CARBON INSTITUTE

Visit shalebubble.org for an interactive map of shale plays, related reports, and other resources.

About the Author

J. David Hughes is a geoscientist who has studied the energy resources of Canada for nearly four decades, including 32 years with the Geological Survey of Canada as a scientist and research manager. He developed the National Coal Inventory to determine the availability and environmental constraints associated with Canada's coal resources. As Team Leader for Unconventional Gas on the Canadian Gas Potential Committee, he coordinated the recent publication of a comprehensive assessment of Canada's unconventional natural gas potential. Over the past decade, he has researched, published, and lectured widely on global energy and sustainability issues in North America and internationally. He is a Fellow of the Post Carbon Institute and his work has been featured in the popular press, radio, television, and other public media. He is currently president of Global Sustainability Research Inc., a consultancy dedicated to research on energy and sustainability issues.

Acknowledgments

The author would like to thank the following reviewers for their time and efforts: Jeffrey Brown, David Fridley, Jeremy Gilbert, Richard Heinberg, Daniel Lerch, Andrew Miall, Asher Miller, Deborah Rogers, and Randy Udall. Photo credits: cover, Garth Lenz; page 2, Songquan Deng / Shutterstock; pages 47 and 153, Mark Schmerling; page 162, Wesley Pohl / iStockphoto.

Drill, Baby, Drill: Can Unconventional Fuels Usher in a New Era of Energy Abundance?
By J. David Hughes

Post Carbon Institute
Santa Rosa, California, USA
www.postcarbon.org

Executive Summary

World energy consumption has more than doubled since the energy crises of the 1970s, and more than 80 percent of this is provided by fossil fuels. In the next 24 years world consumption is forecast to grow by a further 44 percent—and U.S. consumption a further seven percent—with fossil fuels continuing to provide around 80 percent of total demand.

Where will these fossil fuels come from? There has been great enthusiasm recently for a renaissance in the production of oil and natural gas, particularly for the United States. Starting with calls in the 2008 presidential election to "drill, baby, drill!," politicians and industry leaders alike now hail "one hundred years of gas" and anticipate the U.S. regaining its crown as the world's foremost oil producer. Much of this optimism is based on the application of technologies like hydraulic fracturing ("fracking") and horizontal drilling to previously inaccessible shale reservoirs, and the development of unconventional sources such as tar sands and oil shale. Globally there is great hope for vast increases in oil production from underdeveloped regions such as Iraq.

However, the real challenges—and costs—of 21st century fossil fuel production suggest that such vastly increased supplies will not be easily achieved or even possible. The geological and environmental realities of trying to fulfill these exuberant proclamations deserve a closer look.

Context: History and forecasts

Despite the rhetoric, the United States is highly unlikely to become energy independent unless rates of energy consumption are radically reduced. The much-heralded reduction of oil imports in the past few years has in fact been just as much a story of reduced consumption, primarily related to the Great Recession, as it has been a story of increased production. Crude oil production in the U.S. provides only 34 percent of current liquids supply, with imports providing 42 percent (the balance is provided by natural gas liquids, refinery gains, and biofuels). In fact, the Energy Information Administration (EIA) sees U.S. domestic crude oil production—even including tight oil (shale oil)—peaking at 7.5 million barrels per day (mbd) in 2019 (well below the all-time U.S. peak of 9.6 mbd in 1970), and by 2040 the share of domestically produced crude oil is projected to be lower than it is today, at 32 percent. And yet, the media onslaught of a forthcoming energy bonanza persists.

Metrics: Size, Rate of Supply, and Net Energy

The metric most commonly cited to suggest a new age of fossil fuels is the estimate of *in situ* unconventional resources and the purported fraction that can be recovered. These estimates are then divided by current consumption rates to produce many decades or centuries of future consumption. In fact, two other metrics are critically important in determining the viability of an energy resource:

- *The rate of energy supply*—that is, the rate at which the resource can be produced. A large in situ resource does society little good if it cannot be produced consistently and in large enough quantities—characteristics that are constrained by geological, geochemical, and geographical factors (and subsequently manifested in economic costs). For example, although resources such as oil shale, gas hydrates, and in situ coal gasification have a very large in situ potential, they have been produced at only miniscule rates, if at all, despite major expenditures over many years on pilot projects. Tar sands similarly have immense in situ resources, but more than four decades of very large capital inputs and collateral environmental impacts have yielded production of less than two percent of world oil requirements.

- *The net energy yield* of the resource, which is the difference between the energy input required to produce the resource and the energy contained in the final product. The net energy, or "energy returned on energy invested" (EROEI), of unconventional resources is generally much lower than for conventional resources. Lower EROEI translates to higher production costs, lower production rates, and usually more collateral environmental damage in extraction.

Thus the world faces not so much a *resource* problem as a *rate of supply* problem, along with the problem of the collateral environmental impacts of maintaining sufficient rates of supply.

DATA: PRODUCTION, TRENDS, AND CONSTRAINTS

This report provides an in-depth evaluation of the various unconventional energy resources behind the recent "energy independence" rhetoric, particularly shale gas, tight oil (shale oil), and tar sands. In particular, the shale portions of this report are based on the analysis of production data for 65,000 wells from 31 shale plays using the DI Desktop/HPDI database, which is widely used in industry and government.

Shale gas

Shale gas production has grown explosively to account for nearly 40 percent of U.S. natural gas production. Nevertheless, production has been on a plateau since December 2011; 80 percent of shale gas production comes from five plays, several of which are in decline. The very high decline rates of shale gas wells require continuous inputs of capital—estimated at $42 billion per year to drill more than 7,000 wells—in order to maintain production. In comparison, the value of shale gas produced in 2012 was just $32.5 billion.

The best shale plays, like the Haynesville (which is already in decline) are relatively rare, and the number of wells and capital input required to maintain production will increase going forward as the best areas within these plays are depleted. High collateral environmental impacts have been followed by pushback from citizens, resulting in moratoriums in New York State and Maryland and protests in other states. Shale gas production growth has been offset by declines in conventional gas production, resulting in only modest gas production growth overall. Moreover, the basic economic viability of many shale gas plays is questionable in the current gas price environment.

Tight oil (shale oil)

Tight oil production has grown impressively and now makes up about 20 percent of U.S. oil production. This has helped U.S. crude oil production reverse years of decline and grow 16 percent above its all-time post-1970 low in 2008. More than 80 percent of tight oil production is from two unique plays: the Bakken in North Dakota and Montana, and the Eagle Ford in southern Texas. The remaining nineteen tight oil plays amount to less than 20 percent of total production, illustrating the fact that high-productivity tight oil plays are in fact quite rare.

Tight oil plays are characterized by high decline rates, and it is estimated that more than 6,000 wells (at a cost of $35 billion annually) are required to maintain production, of which 1,542 wells annually (at a cost of $14 billion) are needed in the Eagle Ford and Bakken plays alone to offset declines. As some shale wells produce substantial amounts of both gas and liquids, taken together shale gas and tight oil require about 8,600 wells per year at a cost of over $48 billion to offset declines. Tight oil production is projected to grow substantially from current levels to a peak in 2017 at 2.3 million barrels per day. At that point, all drilling locations will have been used in the two largest plays (Bakken and Eagle Ford) and production will collapse back to 2012 levels by 2019, and to 0.7 million barrels per day by 2025. In short, tight oil production from these plays will be a bubble of about ten years' duration.

Tar sands

Tar sands oil is primarily imported to the U.S. from Canada (the number one supplier of U.S. oil imports), although it has recently been approved for development in Utah. It is low-net-energy oil, requiring very high levels of capital inputs (with some estimates of over $100 per barrel required for mining with upgrading in Canada) and creating significant collateral environmental impacts. Additionally it is very time- and capital-intensive to grow tar sands oil production, which limits the potential for increasing production rates.

Production growth forecasts have tended to be very aggressive, but they are unlikely to be met owing to logistical constraints on infrastructure development and the fact that the highest quality, most economically viable portions of the resource are being extracted first. The economics of much of the vast purported remaining extractable resources are increasingly questionable, and the net energy available from them will diminish toward the breakeven point long before they are completely extracted.

Other resources

Other unconventional fossil fuel resources, such as oil shale (not to be confused with shale oil), coalbed methane, gas hydrates, and Arctic oil and gas—as well as technologies like coal- and gas-to-liquids, and in situ coal gasification—are also sometimes proclaimed to be the next great energy hope. But each of these is likely to be a small player in terms of rate of supply for the foreseeable future even though they have large *in situ* resources.

Deepwater oil and gas production make up a notable (yet still small) share of U.S. energy consumption, but growth prospects for these resources are minimal, and opening up coastal areas currently under moratoriums would expand access to only relatively minor additional resources. Production of biofuels (although they are not fossil fuels) is projected to be essentially flat for at least the next two decades (while requiring significant fossil fuel inputs) and will remain a minor player in terms of liquid fuel consumption.

CONCLUSION

The U.S. is a mature exploration and development province for oil and gas. New technologies of large scale, multistage, hydraulic fracturing of horizontal wells have allowed previously inaccessible shale gas and tight oil to reverse the long-standing decline of U.S. oil and gas production. This production growth is important and has provided some breathing room. Nevertheless, the projections by pundits and some government agencies that these technologies can provide endless growth heralding a new era of "energy independence," in which the U.S. will become a substantial net exporter of energy, are entirely unwarranted based on the fundamentals. At the end of the day, fossil fuels are finite and these exuberant forecasts will prove to be extremely difficult or impossible to achieve.

Executive Summary

A new energy dialogue is needed in the U.S. with an understanding of the true potential, limitations, and costs—both financial and environmental—of the various fossil fuel energy panaceas being touted by industry and government proponents. The U.S. cannot drill and frack its way to “energy independence.” At best, shale gas, tight oil, tar sands, and other unconventional resources provide a temporary reprieve from having to deal with the real problems: fossil fuels are finite, and production of new fossil fuel resources tends to be increasingly expensive and environmentally damaging. Fossil fuels are the foundation of our modern global economy, but continued reliance on them creates increasing risks for society that transcend our economic, environmental, and geopolitical challenges. The best responses to this conundrum will entail a rethink of our current energy trajectory.

Unfortunately, the “drill, baby, drill” rhetoric in recent U.S. elections belies any understanding of the real energy problems facing society. The risks of ignoring these energy challenges are immense. Developed nations like the United States consume (on a per capita basis) four times as much energy as China and seventeen times as much as India. Most of the future growth in energy consumption is projected to occur in the developing world. Constraints in energy supply are certain to strain future international relations in unpredictable ways and threaten U.S. and global economic and political stability. The sooner the real problems are recognized by political leaders, the sooner real solutions to our long term energy problem can be implemented.

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INTRODUCTION

Fossil fuels have underpinned an exponential increase in human development and population over the past two centuries. Energy throughput has increased 50-fold since 1850 while population has increased more than five-fold over the same time period. Each human inhabiting this planet now consumes on average nearly nine times as much energy as individuals in 1850 did, and more than 80 percent of this energy is provided by fossil fuels. Given that fossil fuels are non-renewable and hence finite, two critical questions arise: To what extent and on what timeframes can these rates of energy throughput be maintained? And what are the implications if they cannot?

The stakes are very high. The economic paradigm under which governments currently operate requires continuous growth, and growth in gross domestic product (GDP)—particularly since World War II—has been accompanied by growth in consumption of oil and natural gas. But growth also requires relatively affordable energy: 10 of the 11 post-World War II recessions were associated with oil price increases.[1]

Vested interests suggest that even if energy throughput cannot be maintained from conventional sources of oil and gas, unconventional sources such as shale gas, tight oil, oil shale and tar sands offer energy salvation. This rhetoric suggests that energy independence for America is just around the corner, and that if only enough wells can be drilled and enough new areas opened for exploration and development, business-as-usual can continue *ad infinitum*.

How real are these claims? The idea that there are limits to continuous growth is foreign to the economic underpinning of the industrialized world. Politicians are consumed, as are most of those who vote for them, with relighting the fires of economic growth in the wake of the Great Recession. This report endeavors to outline the scale of the problem in maintaining and growing energy throughput and examines some of the realities surrounding unconventional sources of oil and gas. It also examines the implications of what is likely to be the inevitable failure of technology and human ingenuity to continuously expand energy supplies in the face of resource limitations and the collateral environmental damage of attempting to do so. Finally, some thoughts are offered on a strategy to manage some of these issues.

[1] James Hamilton, "Historical Oil Shocks," National Bureau of Economic Research, Working Paper No. 16790, February 2011, http://www.nber.org/papers/w16790.pdf.

THE CONTEXT OF ENERGY PRODUCTION & CONSUMPTION

The Context of Energy Production & Consumption

Public decisions about energy are often muddied by rhetoric, vested interests, and unrealistic expectations. This section endeavors to lay out the realities of the modern world's energy situation so that various prognostications and forecasts can be understood in context.

Key Takeaways

- World energy consumption has tripled in the past 45 years, and has grown 50-fold since the advent of fossil oil a century and a half ago. More than 80 percent of current energy consumption is obtained from fossil fuels.
- Per capita energy consumption is highly inequitably distributed. Developed nations like the United States consume four times the world average. Aspirations of growth in consumption by the nearly 80 percent of the world's population that lives with less than the current per capita world average will cause unprecedented strains on the world's future energy system.
- Oil is of particular concern given the geopolitical implications of the concentration of exporters in the Middle East, Russia and West Africa and the dependency of most of the developed world on imports.
- In the next 24 years world consumption is forecast to grow by a further 44 percent—and U.S. consumption a further 7 percent—with fossil fuels continuing to provide around 80 percent of total demand. Fuelling this growth will require the equivalent of 71 percent of all fossil fuels consumed since 1850— in just 24 years.
- Recent growth notwithstanding, overall U.S. oil and gas production has long been subject to the law of diminishing returns. Since peak oil production in 1970, the number of operating oil wells in the U.S. has stayed roughly the same while the average productivity per well has declined by 42 percent. Since 1990, the number of operating gas wells in the U.S. has increased by 90 percent while the average productivity per well has declined by 38 percent.
- The U.S. is highly unlikely to achieve "energy independence" unless energy consumption declines very substantially. The latest U.S. government forecasts project that the U.S. will still require 36 percent of its petroleum liquid requirements to be met with imports by 2040, even with very aggressive forecasts of growth in the production of shale gas and tight oil with hydraulic-fracturing technology.
- An examination of previous government forecasts reveals that they invariably overestimate production, as do the even more optimistic projections of many pundits. Such unwarranted optimism is not helpful in designing a sustainable energy strategy for the future.
- Given the realities of geology, the mature nature of the exploration and development of U.S. oil and gas resources and projected prices, it is unlikely that government projections of production can be met. Nonetheless these forecasts are widely used as a credible assessment of future U.S. energy prospects.
- Future unconventional resources, some of which are inherently very large, must be evaluated not just in terms of their potential *in situ* size, but also in terms of the rate and full-cycle costs (both environmental and financial) at which they can contribute to supply, as well as their net energy yield.

HISTORY

World

Figure 1 illustrates the big picture of growth in total energy consumption over the last 160 years, along with corresponding growth in human population and per capita energy consumption. During this period, fossil fuel consumption has grown to provide the vast majority of energy throughput. Whereas in 1850 more than 80 percent of energy was provided by renewable biomass (wood and so forth), in 2011 nearly 90 percent was provided by non-renewable sources (oil, gas, coal, and uranium). Total energy consumption is a product of population and per capita energy throughput. Over this period, energy consumption grew 50-fold while world population grew by 5.7 times and per capita consumption grew by 8.8 times. Fully 90 percent of the fossil fuel consumed since 1850 has been burned since 1938, 50 percent of it since 1986. The climatic warming observed since 1970 is highly correlated with this rapid increase in fossil fuel consumption and associated greenhouse gas (GHG) emissions.

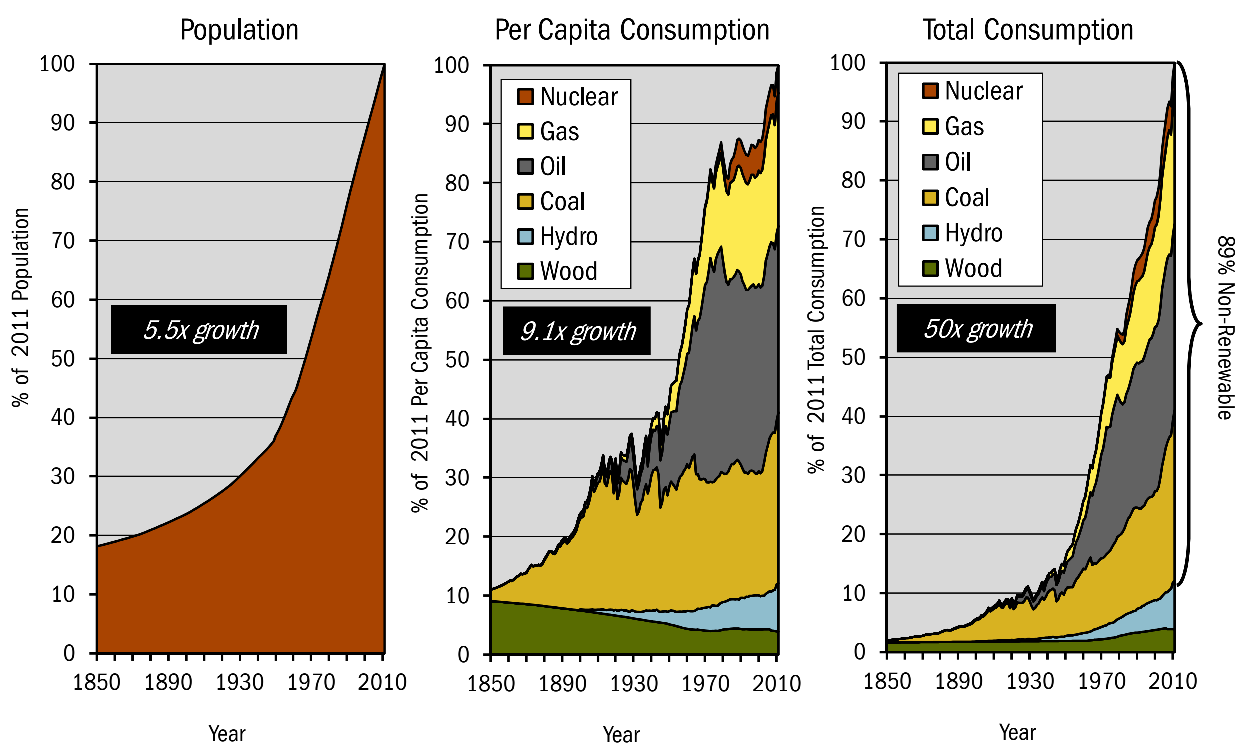
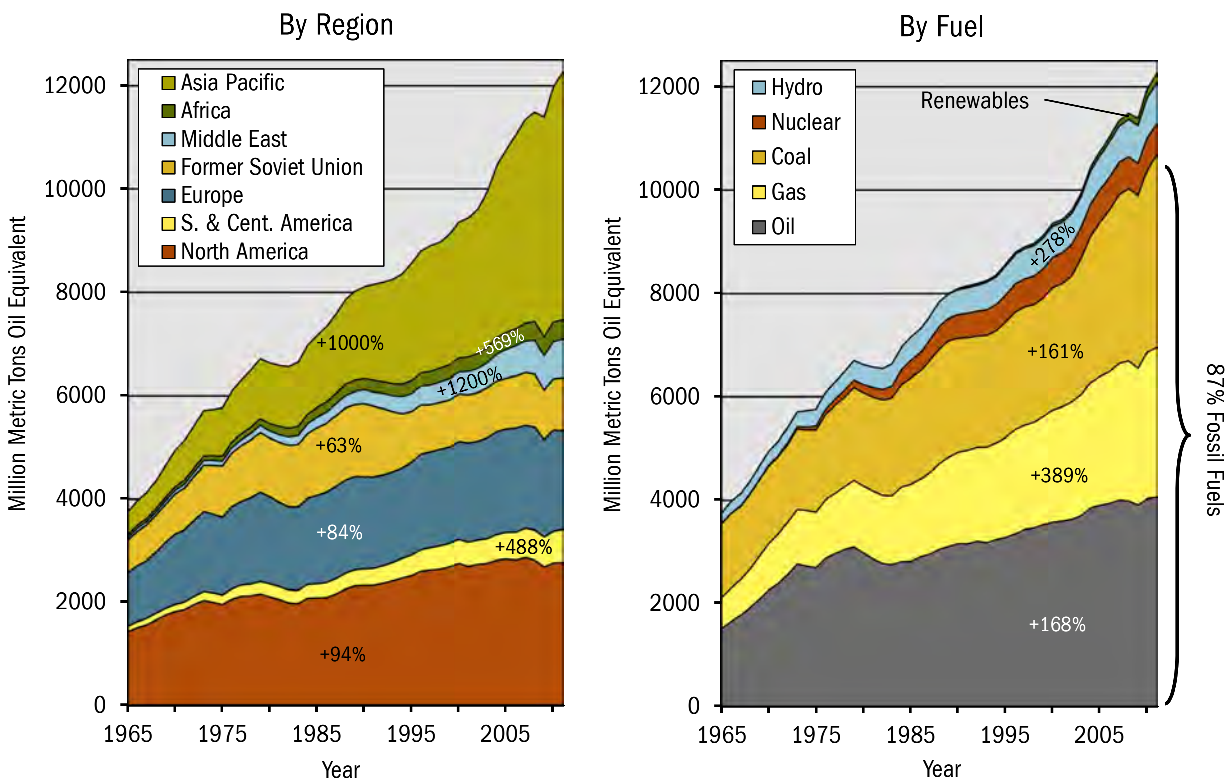


Figure 1. World population, per capita-, and total-energy consumption by fuel as a percentage of 2011 consumption, 1850-2011.[2]

[2] Data from Arnulf Grubler, "Technology and Global Change: Data Appendix," 1998, http://www.iiasa.ac.at/~gruebler/Data/TechnologyAndGlobalChange/; BP, *Statistical Review of World Energy*, 2012, http://www.bp.com/assets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2011/STAGING/local_assets/spreadsheets/statistical_review_of_world_energy_full_report_2012.xlsx; U.S. Census Bureau, 2012, http://www.census.gov/population/international/data/idb/informationGateway.php.

Figure 2 illustrates the growth in world energy consumption by region and fuel since 1965. Global energy consumption has more than tripled over this period and has increased by nearly eight percent in the two years ending in 2011 alone. Oil is the number one source of energy followed by coal and natural gas. On an energy equivalent basis, hydrocarbons comprised 87% of global energy supply in 2011, of which oil and gas comprised 33 and 24 percent, respectively. Non-hydropower renewable energy comprised a mere 1.6 percent of worldwide consumption in 2011 (not including the traditional use of biomass for cooking and heat). The scale of energy consumption and the dependence on hydrocarbons is clearly staggering.



Excludes traditional biomass.

Figure 2. World primary energy consumption by region and fuel, 1965-2011.[3]

Over this period, world energy consumption grew 227%. In 2011 alone, energy consumption grew 2.5%. That year, coal consumption grew the most of the fossil fuels, at 5.4 percent; renewables grew by 17.7 percent but still made up only 1.6 percent of overall consumption.

[3] BP, *Statistical Review of World Energy*, 2012.

On a per capita energy consumption basis, the inequities in levels of consumption between the industrialized and developing world in 2011 are stark as illustrated by Figure 3. For example, in 2011 the United States consumed 4.2 times the world average per capita energy consumption, and 17 times that of India. Nearly 80 percent of the world lives in energy poverty compared to the United States. The major energy conundrum for this century is that the developing world aspires to consume energy at First World rates—and who can blame them? This will fuel growth in energy demand regardless of what the First World does to reduce consumption and, in an era of constrained energy supplies, will also fuel geopolitical tensions and intense competition for resources.

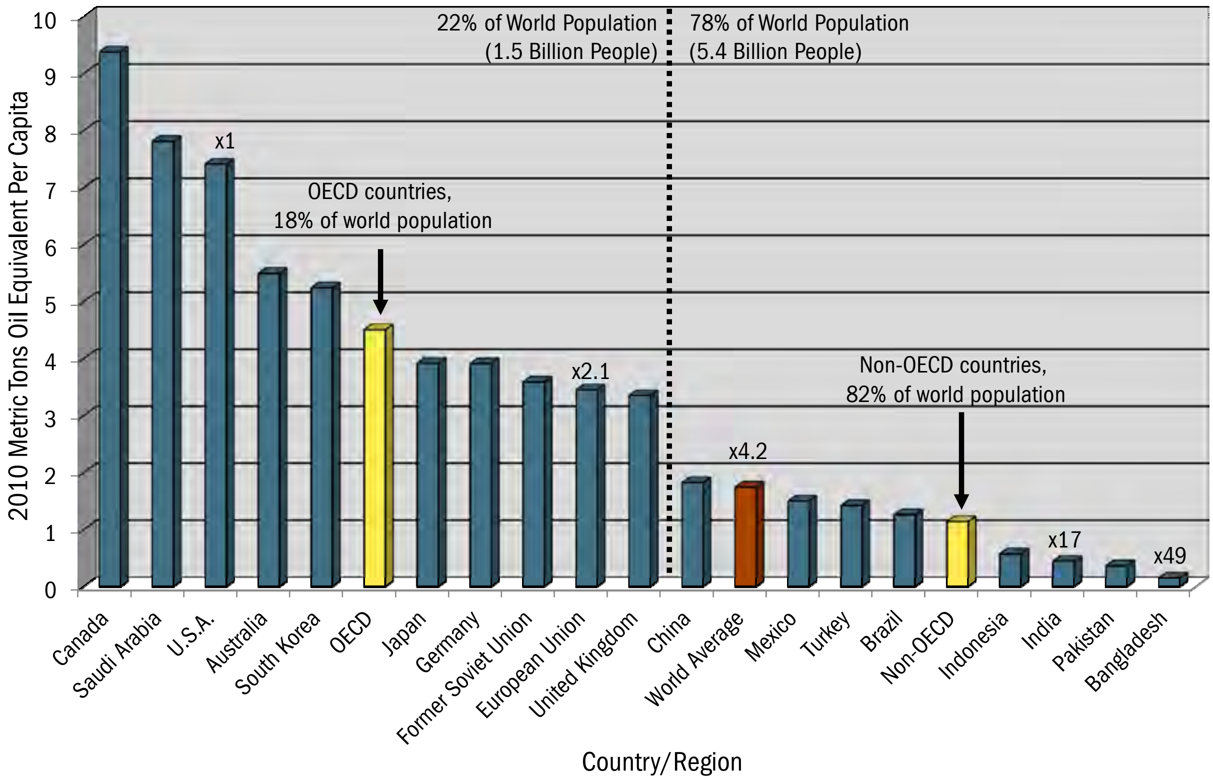


Figure 3. World per capita energy consumption by country and region, 2011.

The comparison of United States consumption to selected countries is indicated by times signs.[4,5]

[4] BP, *Statistical Review of World Energy*, 2011, http://www.bp.com/assets/bp_internet/globalbp/globalbp_uk_english/reports_and_publications/statistical_energy_review_2011/STAGING/local_assets/spreadsheets/statistical_review_of_world_energy_full_report_2011.xlsx.

[5] U.S. Census Bureau, 2011.

Oil

Global oil consumption has nearly tripled since 1965, as illustrated in Figure 4. Consumption has accelerated very rapidly in the developing world, particularly in the Asia Pacific, the Middle East and Africa. Although the Middle East and Africa are very large exporters of oil, the rapid growth in domestic consumption in these regions is providing limits on their ability to increase oil exports.[6] Oil consumption now totals more than 32 billion barrels per year, up from 11 billion barrels per year in 1965. On a cumulative basis since the first oil well was drilled in the late 1850's through 2011, 90 percent of all oil consumed has been burned since 1960 and half since 1988.

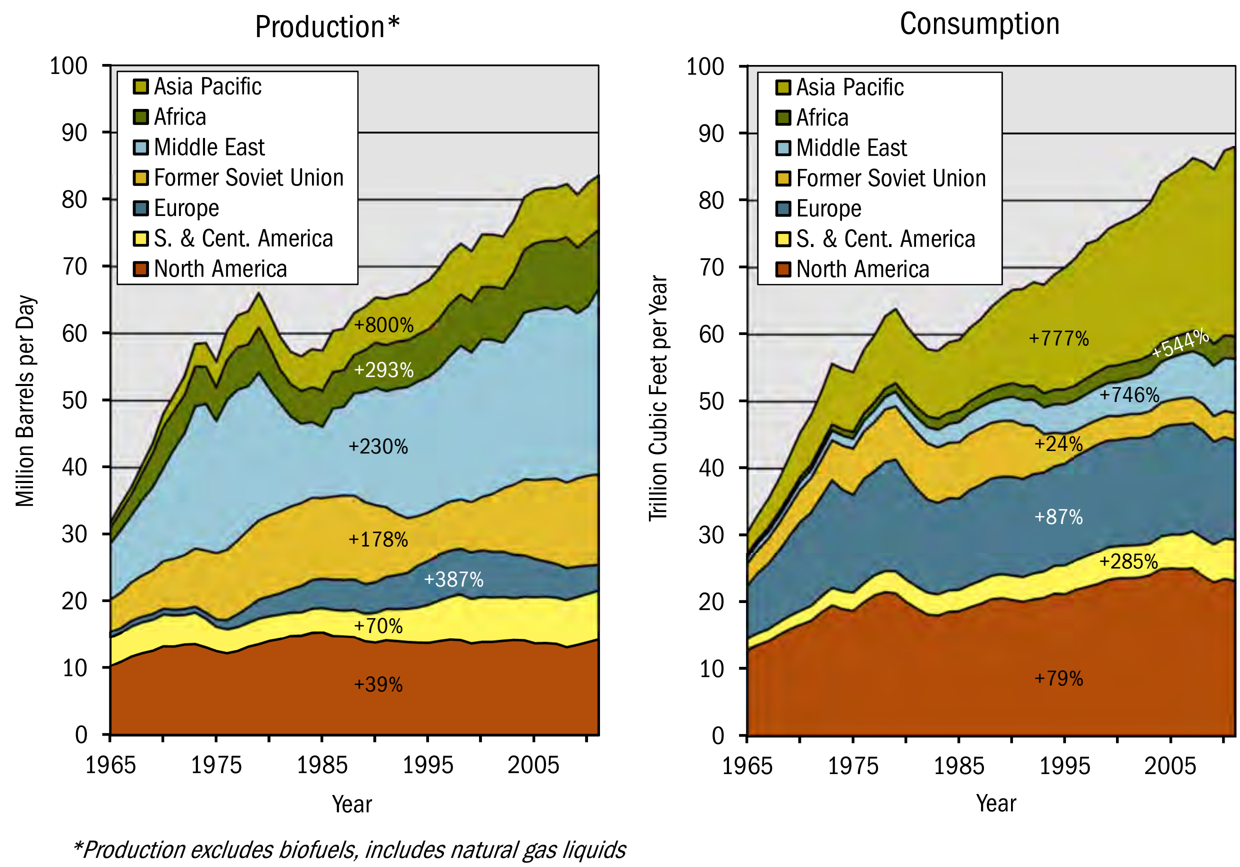


Figure 4. World production and consumption of oil by region, 1965-2011.[7]

Production increased 163% in this period, and 1.3% from 2010 to 2011. Consumption increased 189% in this period, and 0.7% from 2010 to 2011.

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6 Export Land Model developed by Jeffrey Brown http://en.wikipedia.org/wiki/Export_Land_Model.

7 BP, *Statistical Review of World Energy*, 2012.

Oil is the largest source of energy in the world and the premier fuel for transportation. Looking at oil on a per capita consumption basis, the global inequities in consumption are even more stark than with total energy consumption (Figure 5). With the exception of Saudi Arabia, per capita oil consumption is much higher in the industrialized world than in the developing world. The United States, for example, consumes more than 22 barrels of oil per person per year, which is five times the world average and nine times that of China. China, however, now has the largest annual vehicle sales in the world and has become the third largest importer of oil. Interestingly, the European Union has less than half of the United States per capita consumption but is still double the world average. Two-thirds of the world's population uses less than one fifth of United States per capita consumption, and in most cases much less. This sets the stage for geopolitical conflicts if expectations for higher consumption of oil in the developing world cannot be met, even though consumption growth is flat or even slightly declining in the developed world.

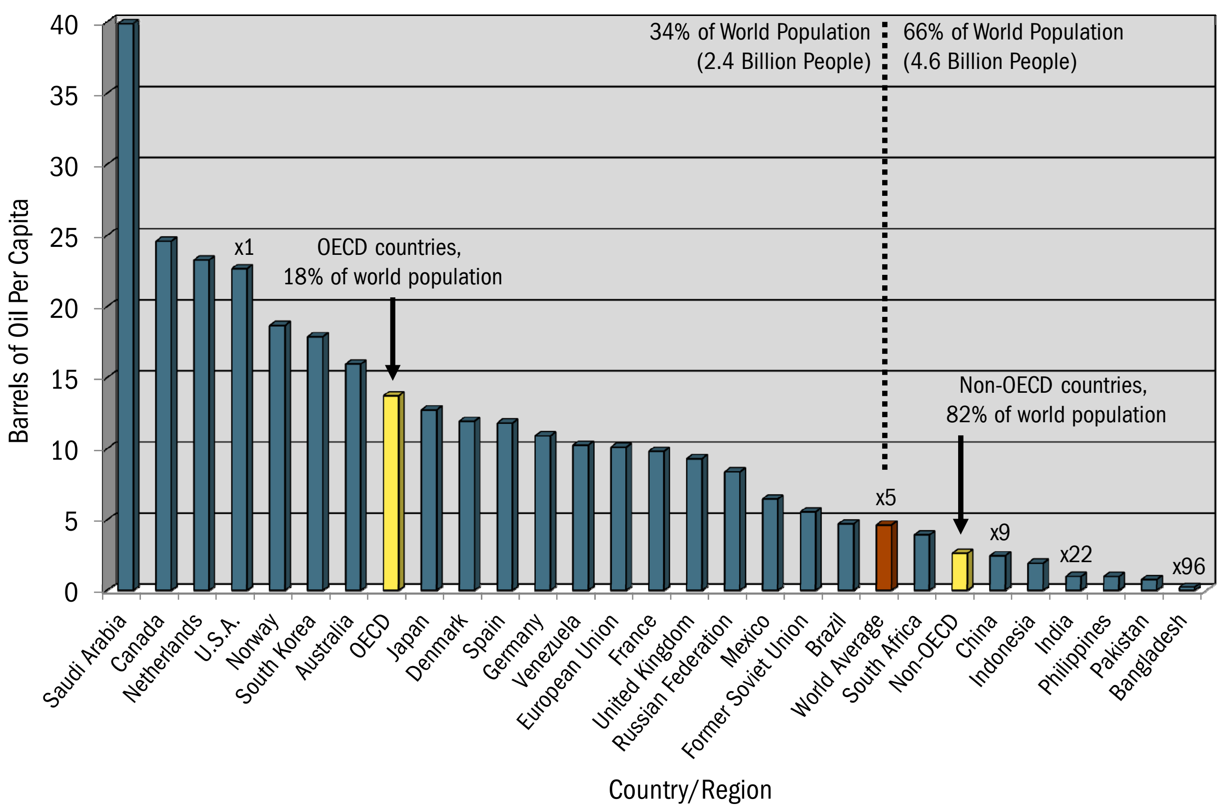

Figure 5. World per capita oil consumption by region, 2010.

The comparison of United States consumption to selected countries is indicated by times signs.[8]

[8] BP, *Statistical Review of World Energy*, 2011; U.S. Census Bureau, 2011.

The rapid growth in oil consumption in the developing world is particularly well illustrated by China (Figure 6). As recently as 1992, China was a net exporter of oil. Total oil consumption has nearly quadrupled since then, and in 2011 China was dependent on imports for 60 percent of its requirements. That year, Chinese oil imports amounted to six million barrels per day, or 7.2% of total global oil production—and in competition with other major oil importers such as Europe, the United States, and Japan. China's growth in oil consumption over the past few years has paralleled its economic growth rates of 5-10% per year.

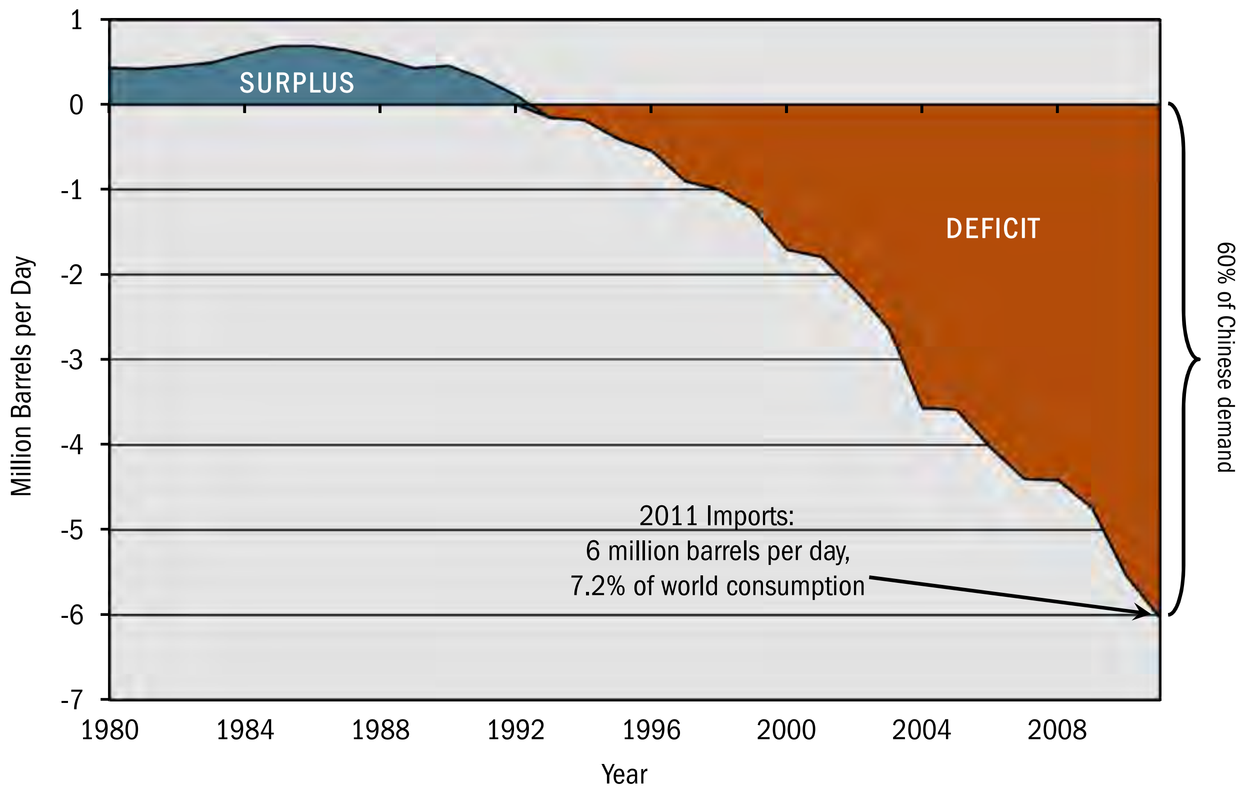

Figure 6. China's oil production surplus and deficit, 1980-2011.[9]

[9] BP, *Statistical Review of World Energy*, 2012.

The stage for geopolitical confrontations on oil supply is set. The dependency of the industrialized world on often unstable regions is illustrated in Figure 7. The top three oil importers—Europe, the United States, and China—are highly dependent on the Middle East, the Former Soviet Union, and West Africa, regions fraught with politically instability. The geopolitical conflicts that could be precipitated with rising oil consumption expectations in the face of restricted supply are obvious.

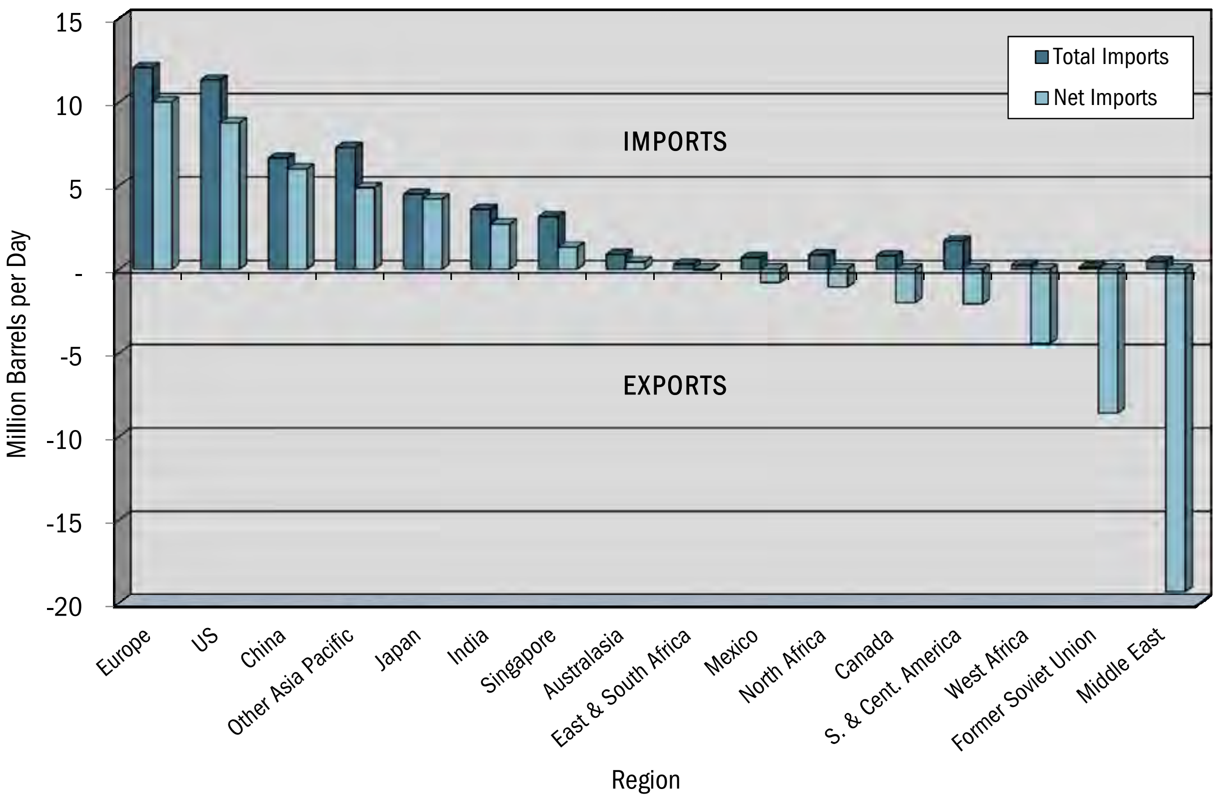

Figure 7. World total and net imports and exports by region, 2011.[10]

The industrialized economies of Europe, the United States, Japan, and Australia/New Zealand, along with the developing economies of China, India, and developing Asia, are highly dependent on the Middle East, the Former Soviet Union, and West Africa for oil imports.

[10] BP, *Statistical Review of World Energy*, 2012.

Natural Gas

Global production and consumption of natural gas by region is illustrated in Figure 8. Consumption has more than tripled since 1970. Unlike oil, which is a fungible commodity traded on a global basis, natural gas has so far largely been priced on a continental basis, owing to the relative difficulty of moving it between continents via liquefied natural gas (LNG) tankers, compared to oil. Only about ten percent of global gas consumption was consumed as LNG in 2011.This has resulted in deep discounts in the price of gas in North America compared to European and Asian markets, and to the aggressive push by North American gas producers to develop LNG infrastructure to export gas to higher-priced markets. As with oil, consumption of gas has increased very rapidly in the Asia Pacific, Africa, and the Middle East.

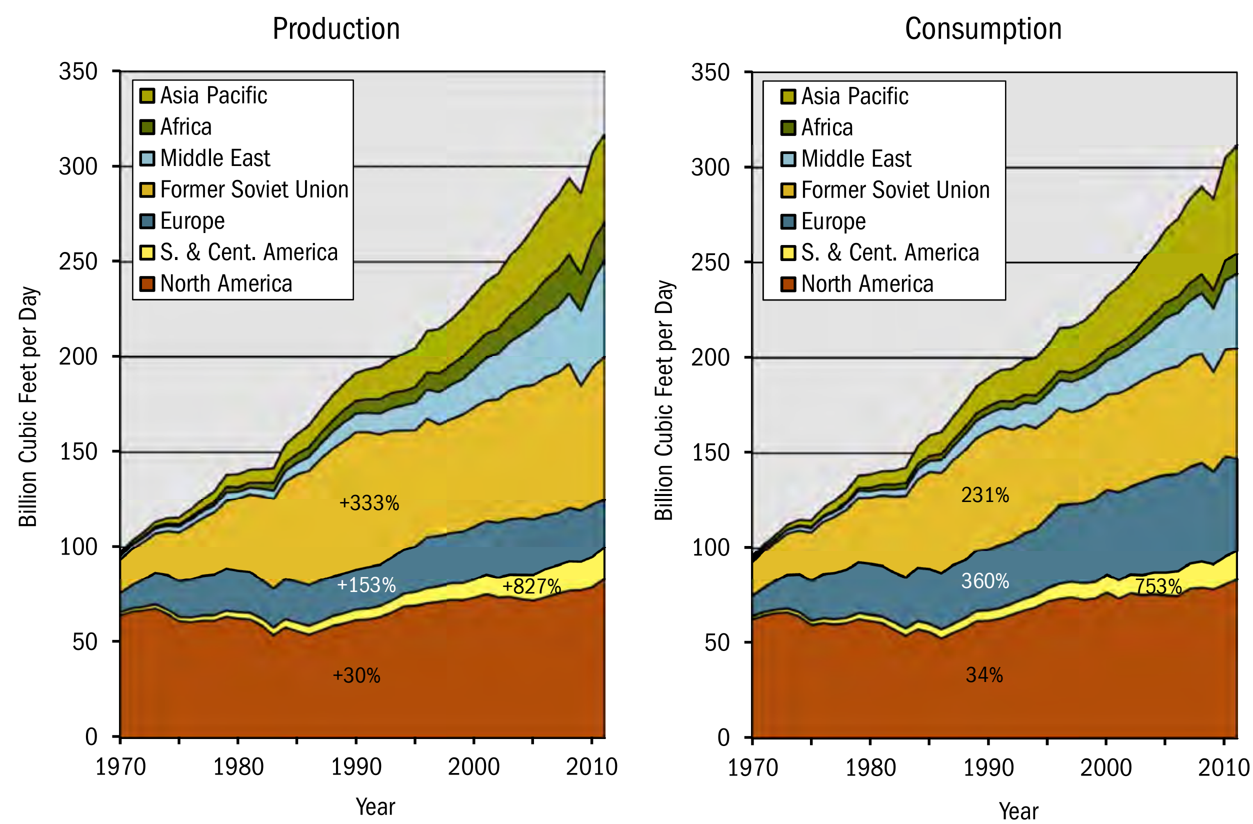

Figure 8. World natural gas production and consumption, 1965-2011.[11]

Production increased 227% in this period, and 3.1% from 2010 to 2011. Consumption increased 227% in this period, and 2.2% from 2010 to 2011.

[11] BP, *Statistical Review of World Energy*, 2012.

United States

Energy consumption and production in the United States over the past three decades is illustrated in Figure 9. Over this period production of energy from all sources increased by 16 percent whereas consumption increased by 29 percent. As a result, 20 percent of U.S. energy consumption was imported in 2011, up from 11 percent in 1981. More than 86 percent of 2011 energy consumption was provided by fossil fuels with the balance by nuclear (8.3%), hydro (3.3%) and renewables (2%).

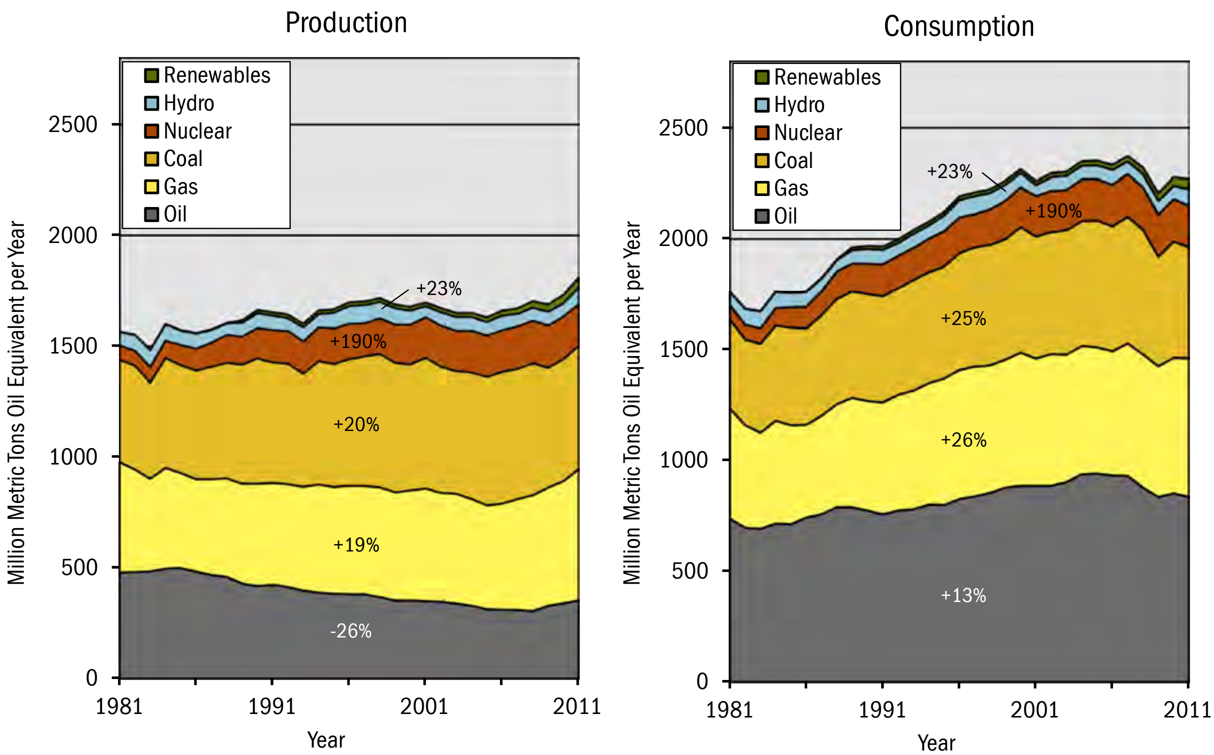

Figure 9. U.S. production and consumption of energy by fuel, 1981-2011.[12]

Production increased 15.6% in this period, and 4.4% from 2010 to 2011. Consumption increased 29% in this period, but decreased 0.4% from 2010 to 2011.

[12] BP, *Statistical Review of World Energy*, 2012.

Oil

The imbalance between production and consumption is most pronounced for oil. Production of oil declined 26 percent over the past three decades whereas consumption increased by 13 percent. Figure 10 illustrates the consumption of oil (defined as all petroleum liquids) by source.

Although there has been a great deal of rhetoric lately about the United States becoming "energy independent" in terms of oil thanks to increased production of tight oil and biofuels, 42 percent of 2012 oil consumption came still from imports. Only 34 percent of 2012 consumption was provided by domestic crude oil production with the balance of liquids from refinery gains, natural gas liquids and biofuels—sources which are lower in energy content than crude oil and, in the case of natural gas liquids, are not fully substitutable for crude oil as has been pointed out by several authors.[13,14]

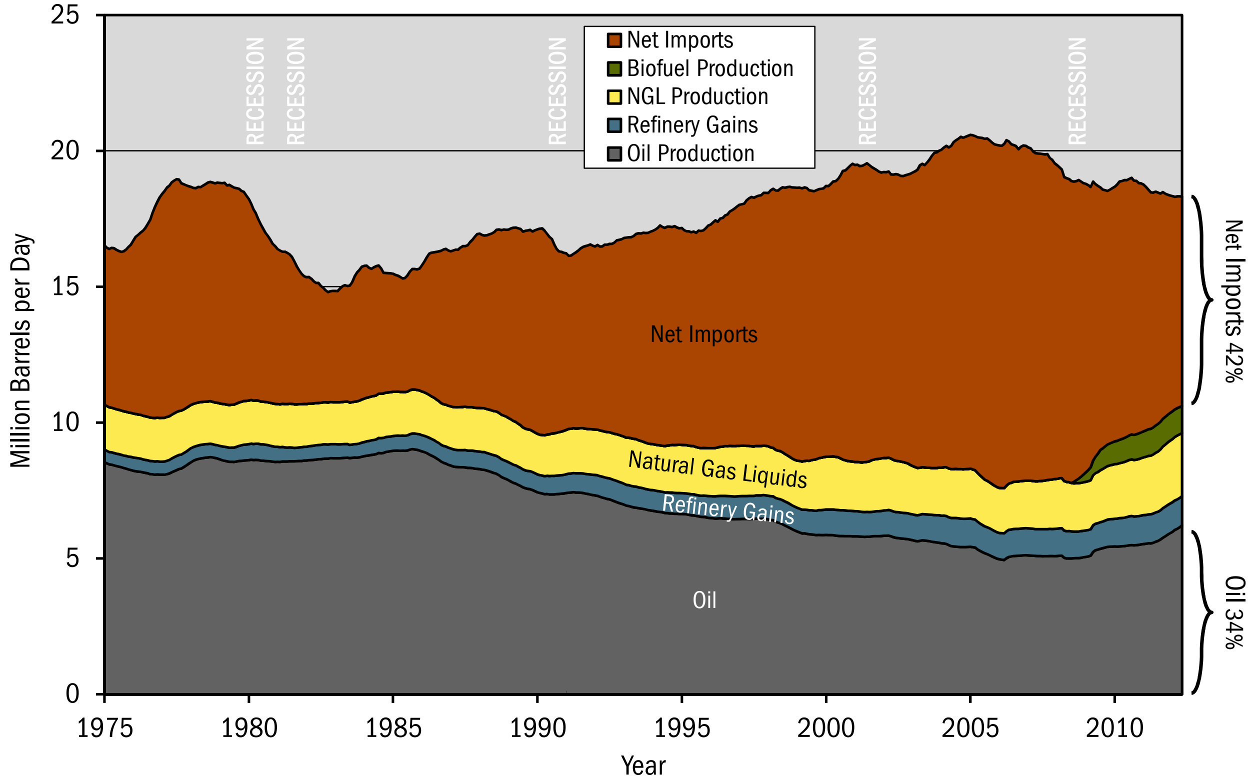

Figure 10. U.S. consumption of petroleum liquids by source, 1975-2012.[15]
Economic recessions are also indicated to illustrate their correlation with reduced consumption.

13 Michael Levi, "Are natural gas liquids as good as oil?", Council on Foreign Relations, July 9, 2012, http://blogs.cfr.org/levi/2012/07/09/are-natural-gas-liquids-as-good-as-oil/.

14 James Hamilton, "Natural Gas Liquids", Econbrowser, 2012, http://www.econbrowser.com/archives/2012/07/natural_gas_liq.html.

15 EIA, December, 2012, 12-month centered moving average, http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T03.01; http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_m.htm.

Economic recessions, as pointed out in Figure 10, generally repress oil consumption, and indeed United States consumption has been reduced by nearly 10 percent since the advent of the "Great Recession" in 2008. Although some of this reduced consumption was undoubtedly caused by increased efficiency in the use of oil, most of it was caused by economic hardship and high levels of unemployment, as well as historically high prices, which impacted transportation as well as the industrial sector. As a result of reduced domestic demand, exports of refined petroleum products increased, which reduced total 2012 oil imports of 10.8 million barrels per day (mbd) to net imports of 7.7 mbd as illustrated in Figure 11.

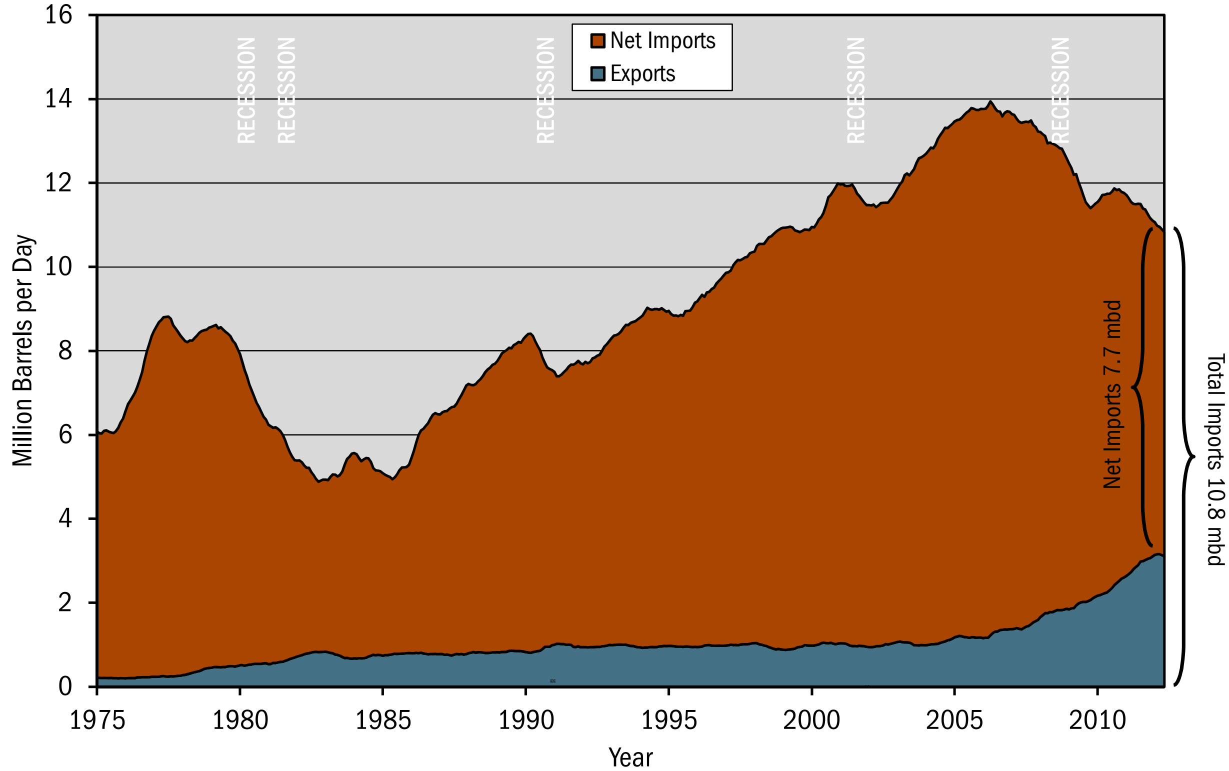

Figure 11. U.S. petroleum liquids imports, exports and net imports, 1975-2012.[16]

Economic recessions are also indicated to illustrate their correlation with reduced consumption and therefore lower requirements for imported oil.

16 EIA, December, 2012, 12-month centered moving average, http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T03.03B.

Seventy percent of United States oil consumption is used in the transportation sector, 23 percent in the industrial sector and the balance in the commercial, residential and electrical sectors (Figure 12). Since the all-time peak of oil consumption in late 2006 at 20.8 mbd, United States consumption has fallen by 2.1 mbd with an 8 percent decline in the transportation sector and a 16 percent decline in the industrial sector.

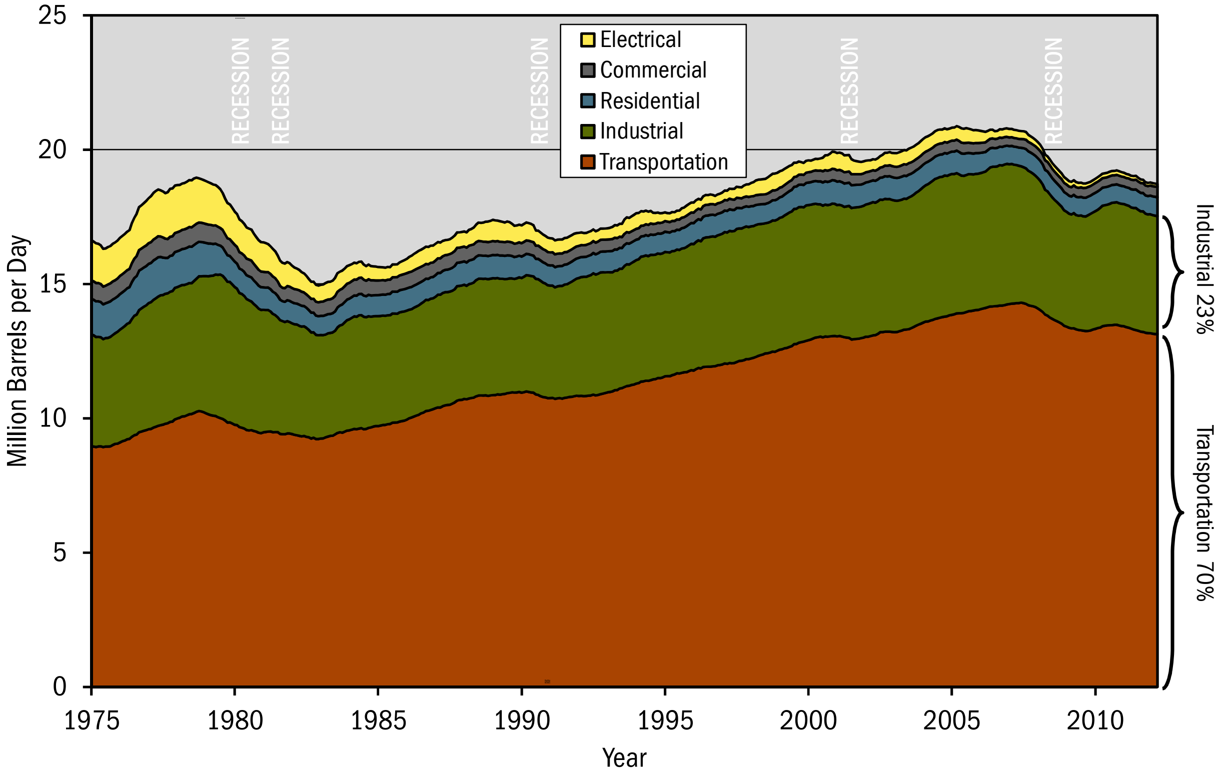

Figure 12. U.S. petroleum liquids consumption by sector, 1975-2012.[17]

Economic recessions are also indicated to illustrate their correlation with reduced consumption. Overall oil consumption has declined by an aggregate of 2.1 mbd since consumption peaked in late 2006.

[17] EIA, December, 2012, 12 centered moving average, http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T03.07A; http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T03.07B; http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T03.07C.

Oil production in the United States rose quickly following the Second World War, reaching a peak of more than 9.6 mbd in 1970. By 2011, however, production had fallen to 5.9 mbd. Production from Prudhoe Bay and other fields on the north slope of Alaska, the largest discoveries in the United States since the 1960's, has fallen 72% since peaking in 1988 and are approaching the minimum operating capacity of the Alyeska pipeline.

Figure 13 illustrates oil production in the United States by region since 1985. With the exception of Texas and North Dakota, home to the Eagle Ford and Bakken tight oil plays, respectively, production in all regions is falling or flat. Much is made of the recent rise in oil production due to the development of tight oil, with some pundits declaring "oil independence" is just around the corner. Yet current total production remains 31% below 1985 levels and 36% below the all-time 1970 peak.

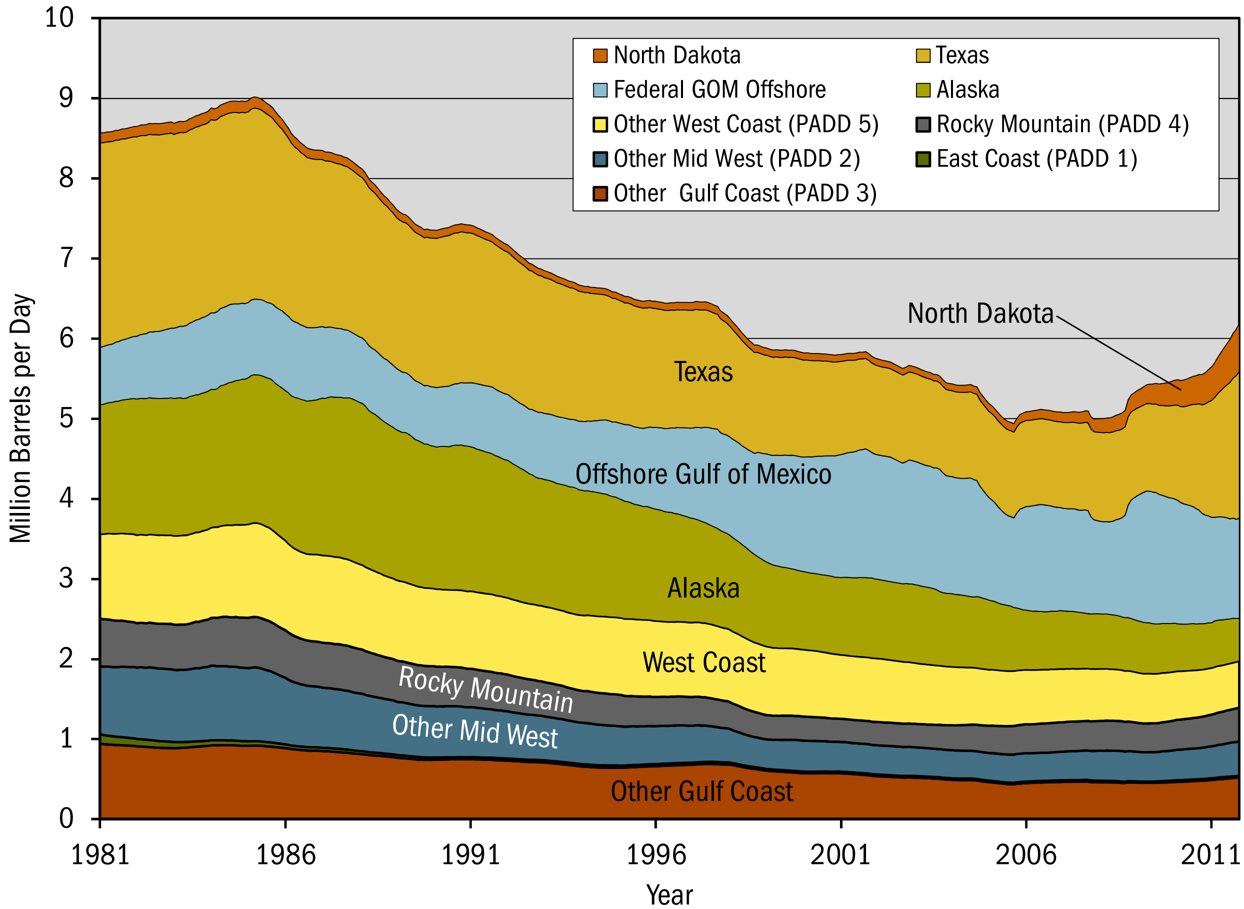

Figure 13. U.S. oil production by region, 1985-2012.[18]
Production has fallen 31 percent over the period.

[18] Data from EIA December, 2012, fitted with 12-month centered moving average, http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_m.htm.

The law of diminishing returns in terms of United States oil production is illustrated in Figure 14. At peak oil production in 1970 the United States had 531,000 operating oil wells averaging a little over 18 barrels per day each. By 2010 the United States had approximately the same number of operating oil wells (530,000), but average productivity had fallen to only 10.4 barrels per day. The question of how many wells and how much production infrastructure the United States would require to achieve independence from foreign oil imports with the new tight oil plays will be dealt with later in this report.

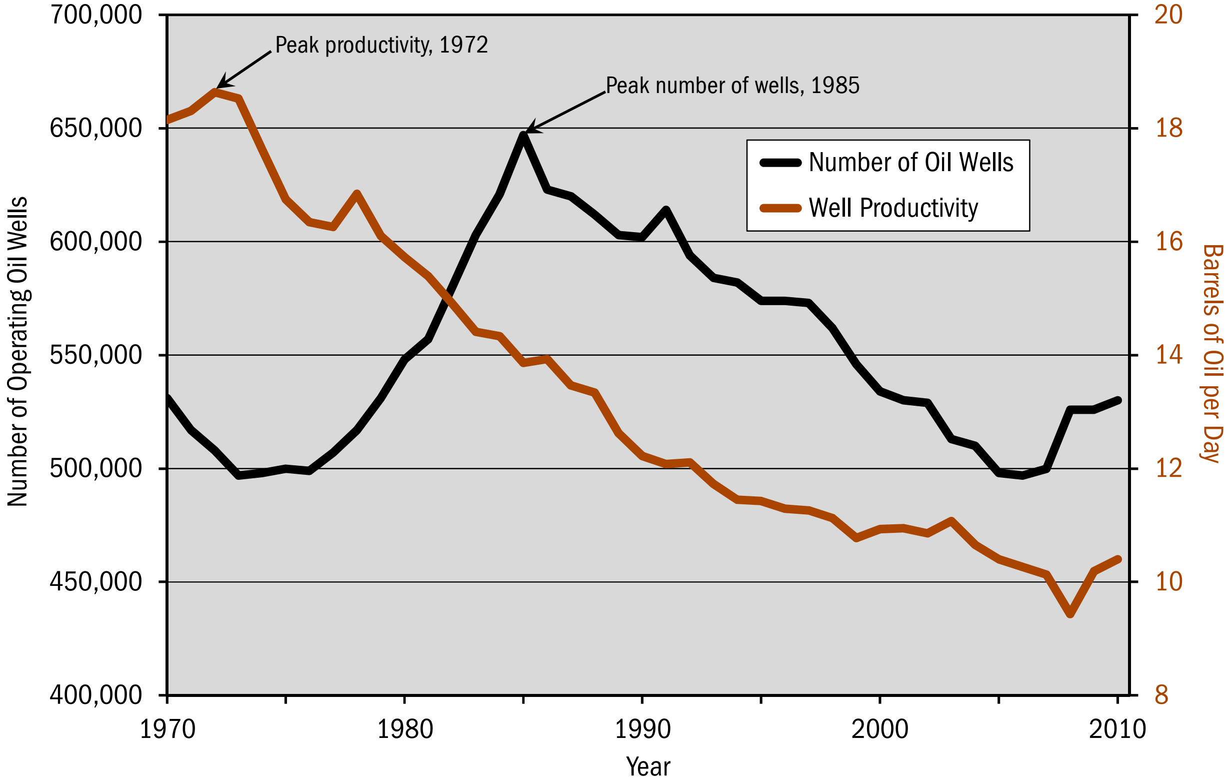

Figure 14. U.S. operating oil wells versus average well productivity, 1970-2010.[19]
Average well productivity has fallen 44 percent over the past four decades.

[19] Data from EIA Annual Energy Review 2011, http://www.eia.gov/totalenergy/data/annual/xls/stb0502.xls.

The exploration and development effort that has been required to raise production by about one mbd from post-1970 lows in 2008 is illustrated in Figure 15. The number of oil wells drilled per year has grown by more than two and a half fold since early 2005, from an average of about 10,000 wells per year in the 1990-2005 period.

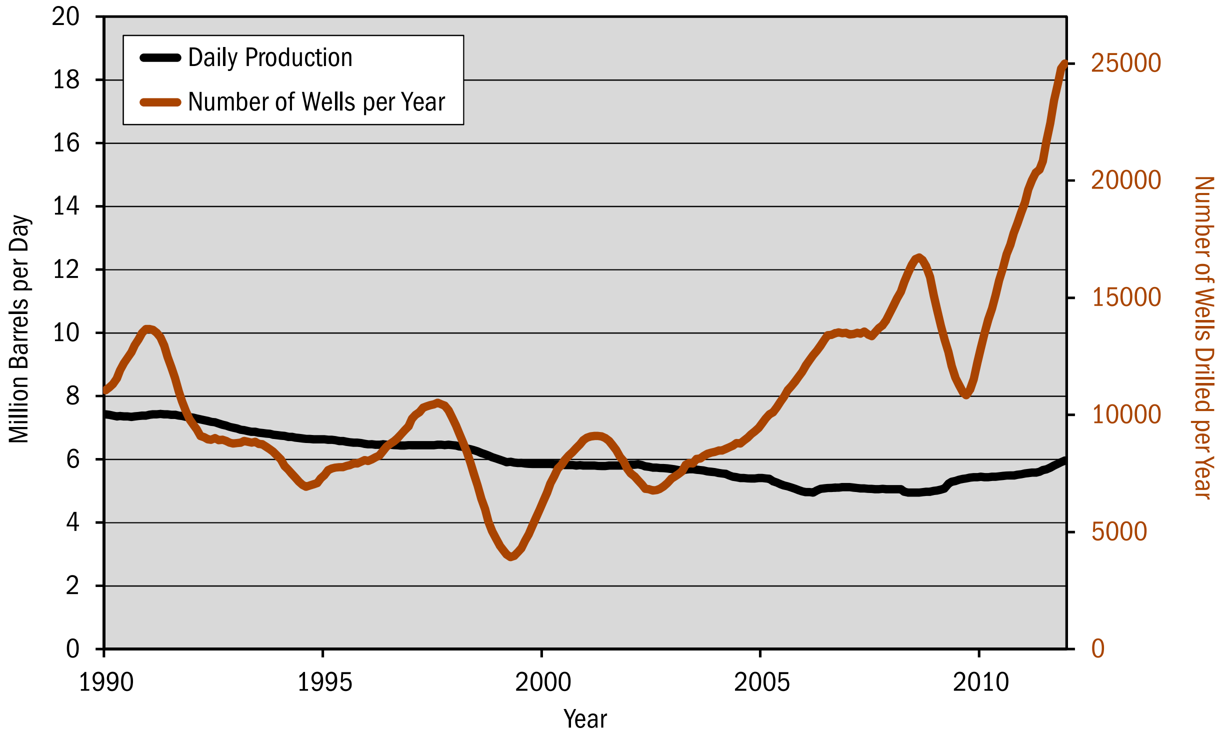

Figure 15. U.S. annual oil well drilling rate and overall oil production, 1990-2012 (12-month centered moving average).[20]

Drilling rates have increased by 159% since early 2005.

[20] Data from EIA July, 2012, 12-month centered moving average, well count from http://www.eia.gov/dnav/ng/ng_enr_wellend_s1_m.htm and oil production from http://www.eia.gov/dnav/pet/xls/pet_crd_crpdn_adc_mbblpd_m.xls.

Natural Gas

Notwithstanding the rise in natural gas production over the past few years due to the development of shale gas, the United States remains a net importer of 8.6 percent of its natural gas requirements as illustrated in Figure 16. Imports are obtained by pipeline from Canada and through liquefied natural gas terminals on the East Coast and in the Gulf of Mexico.

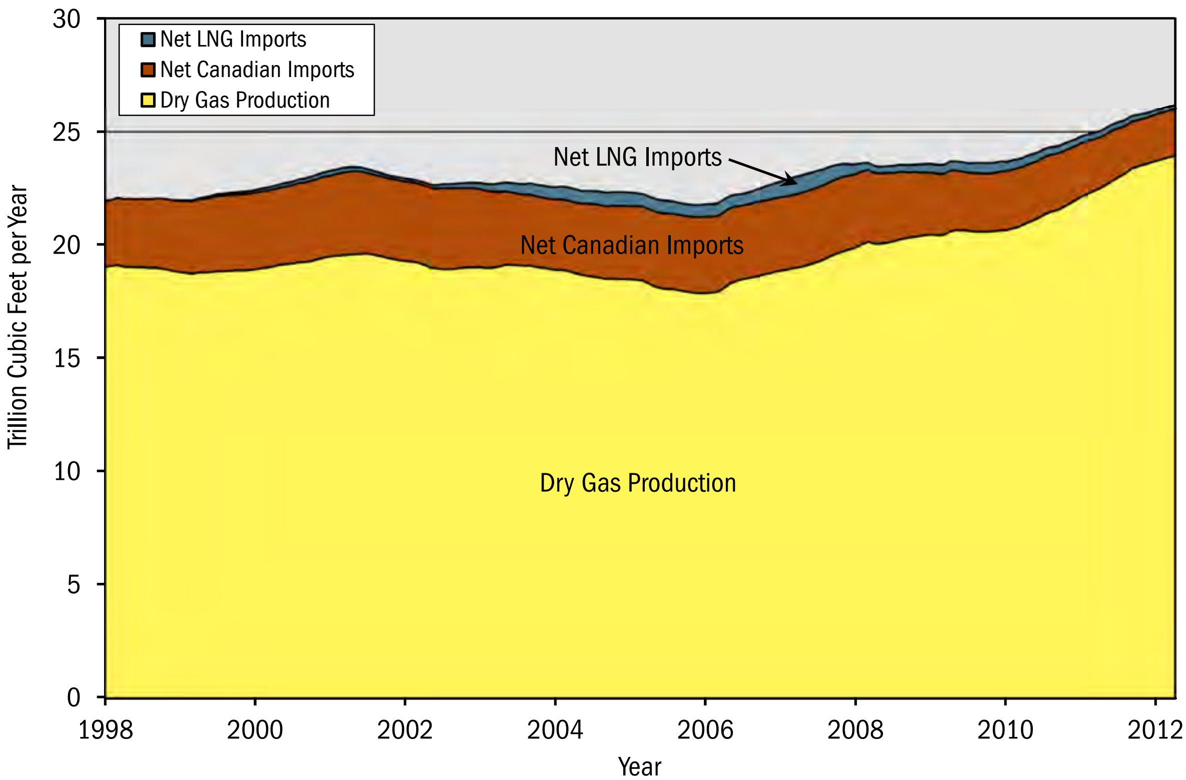

Figure 16. U.S. natural gas supply by source, 1998-2012. [21]

Notwithstanding rising domestic production, imports accounted for 8.6 percent of requirements in mid-2012.

[21] Data from EIA December, 2012, fitted with 12-month centered moving average, http://www.eia.gov/naturalgas/monthly/xls/ngm01vmall.xls; Imports from http://www.eia.gov/naturalgas/monthly/xls/ngm04vmall.xls; Exports from http://www.eia.gov/naturalgas/monthly/xls/ngm05vmall.xls.

Natural gas is a versatile fuel used in a number of sectors as illustrated in Figure 17. Fifty-five percent of consumption is in the industrial, commercial and residential sectors, 8.6 percent is consumed in process of producing and distributing the gas to end users, and the balance is used for electricity generation and transport. At present, electricity generation accounts for 36 percent of consumption and compressed natural gas vehicles a little over a tenth of one percent.

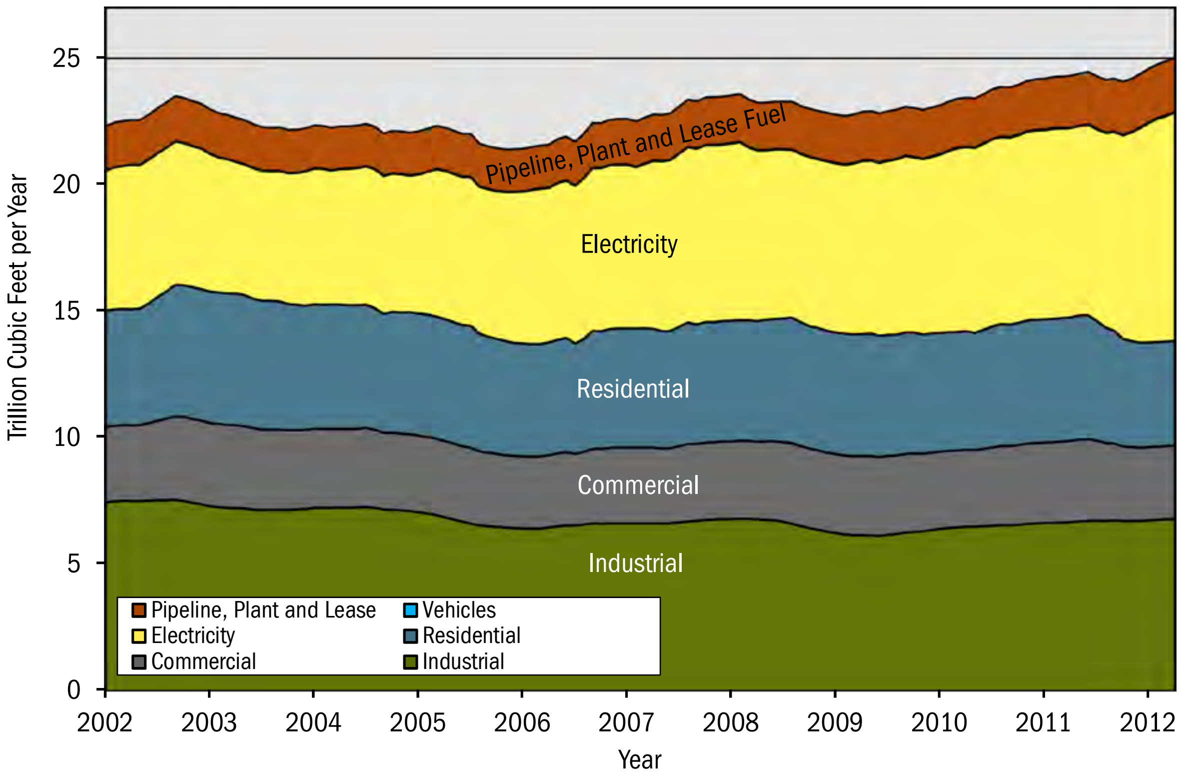

Figure 17. U.S. natural gas consumption by sector, 1998-2012.[22]

[22] Data from EIA December, 2012, fitted with 12-month centered moving average, http://www.eia.gov/naturalgas/monthly/xls/ngm02vmall.xls.

Production of natural gas by region is illustrated in Figure 18. Conventional production from some traditional producing areas is in decline, particularly in the offshore Gulf of Mexico, and is flat in others, including New Mexico, Oklahoma, Alaska and Wyoming. Substantial overall production growth is a result of unconventional shale gas production in Louisiana, Texas, and a host of other states. The growth in production, and the assumption that it will continue to do so, has provoked a great deal of speculation on natural gas making substantial inroads on replacing oil for vehicular transport and coal for electricity generation—this was dealt with in an earlier report.[23] The conclusions of this report are that some substitution of coal by gas will occur as older coal plants are retired as long as gas prices remain low, but wholesale replacement is unlikely. Natural gas fuelled vehicles, particularly for fleet uses, will increase to a million or more over the next two decades from their current levels of about 150,000, but will remain a niche use in terms of replacing the 240-million-strong vehicle fleet currently on the road in the United States.

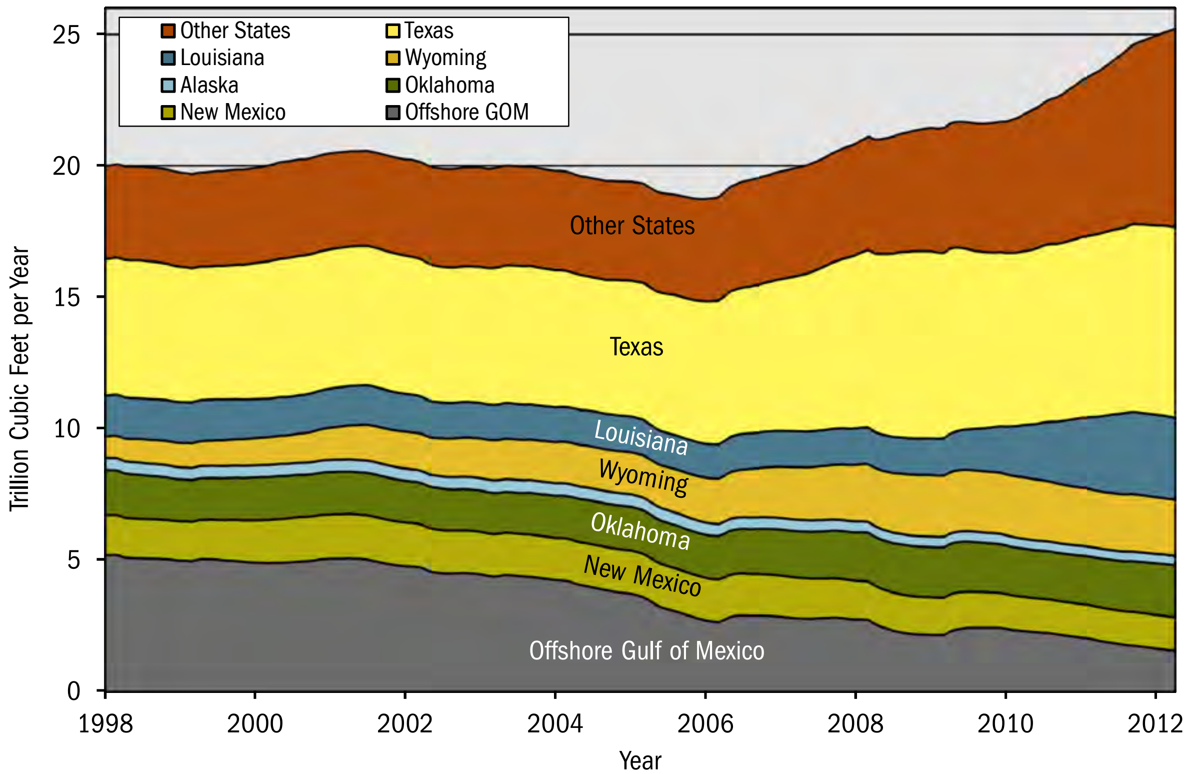

Figure 18. U.S. marketed natural gas production by region, 1998-2012.[24]

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[23] J.D. Hughes, "Will Natural Gas Fuel America in the 21st Century?", Post Carbon Institute, 2011, http://www.postcarbon.org/reports/PCI-report-nat-gas-future-plain.pdf.

[24] Data from EIA December, 2012, fitted with 12-month centered moving average, http://www.eia.gov/naturalgas/monthly/xls/ngm07vmall.xls; Note that marketed production is wet gas and includes gas used for pipeline distribution and at gas plants and leases that is not available to end consumers.

Notwithstanding the fact that the United States is currently a net importer of natural gas to meet its current requirements, enthusiasm over continuing to increase production from shale gas has resulted in several proposals to export natural gas by converting some of the existing liquefied natural gas (LNG) import terminals for export and constructing new export terminals. This would allow producers to capture higher prices on the world market. Currently 29.21 billion cubic feet per day of export capacity, or about 45 percent of current U.S. dry gas production, has been approved or is under consideration by the U.S. Department of Energy.[25] Given issues of geology, engineering, and environmental concerns surrounding shale gas production, which will be dealt with extensively in a later section, the wisdom of exporting this as-yet-nonexistent bounty of natural gas must be questioned.

The law of diminishing returns for United States natural gas production is illustrated in Figure 19. More and more wells must be drilled and operated to maintain production as the average productivity per well is declining. Since 1990, the number of operating gas wells in the United States has increased by 90 percent while the average productivity per well has declined by 38 percent. This is referred to as the "exploration treadmill."

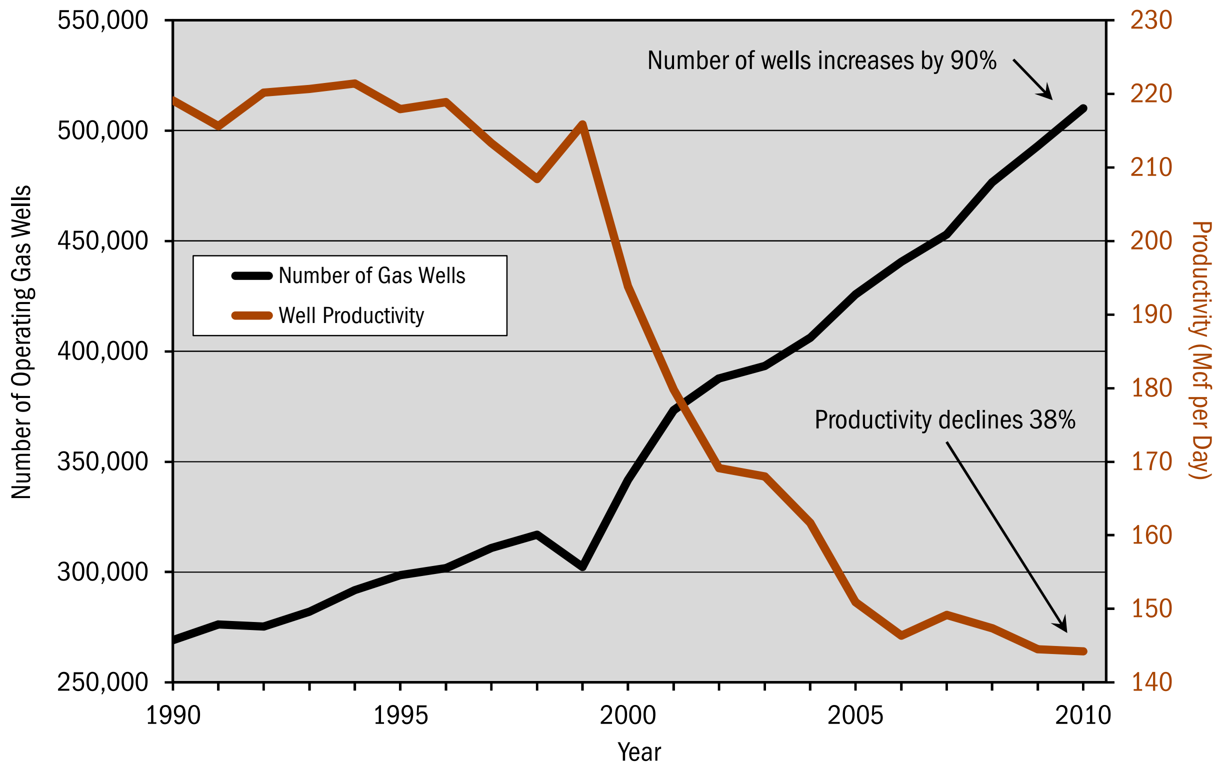

Figure 19. U.S. operating natural gas wells versus average well productivity, 1990-2010.[26]

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[25] U.S. Department of Energy, "Applications Received by DOE/FE to Export Domestically Produced LNG from the Lower-48 States (as of December 19, 2012)", 2012, http://www.fossil.energy.gov/programs/gasregulation/reports/Long%20Term%20LNG%20Export%20Concise%20Summary%20Table%2012-20-12%20nwood.2.pdf.

[26] Data from EIA Annual Energy Review 2011, http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0604.

Figure 20 further illustrates the increased level of drilling required to maintain and grow production. The annual number of natural gas wells drilled has more than tripled from 1990's levels in the 2005 through 2008 timeframe. This massive increase in drilling reversed what appeared to be a terminal decline in production. Production has continued to grow even though the rate of drilling has fallen by more than 50 percent. This is partially a result of the lag time between drilling the wells and connecting them to a pipeline, and partially a result of the generally higher initial productivity of shale gas wells, particularly those from the Haynesville field in Louisiana and eastern Texas (which in terms of productivity, cost and environmental impact, represent several average older gas wells).

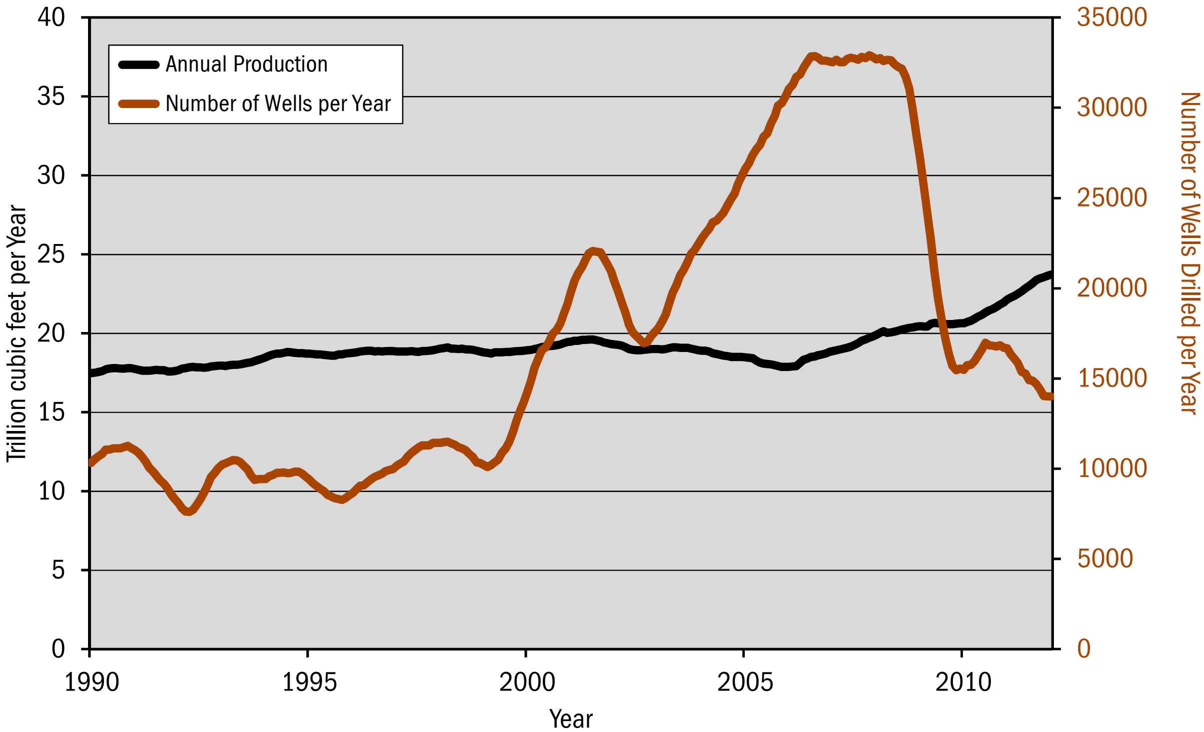

Figure 20. U.S. natural gas production versus annual drilling rate of successful gas wells, 1990-2012.[27]

[27] Data from EIA August, 2012, 12-month centered moving average; data for well count from http://www.eia.gov/dnav/ng/ng_enr_wellend_s1_m.htm and dry gas production from http://www.eia.gov/naturalgas/monthly/xls/ngm01vmall.xls).

FORECASTS

World

The reference case forecast of the U.S. Energy Information Administration (EIA) for growth in world energy consumption through 2035 is illustrated in Figure 21. Overall consumption is projected to grow by 47 percent over 2010 levels by 2035. Although fossil fuels are forecast to decline in market share they still constitute 79 percent of consumption in 2035. Such forecasts assume unfettered access to the resources which will underpin strong economic growth. The question is, how realistic are they given resource limitations, environmental considerations surrounding resource extraction, carbon emissions, and geopolitical issues surrounding the unequal distribution of resources and resource consumption?

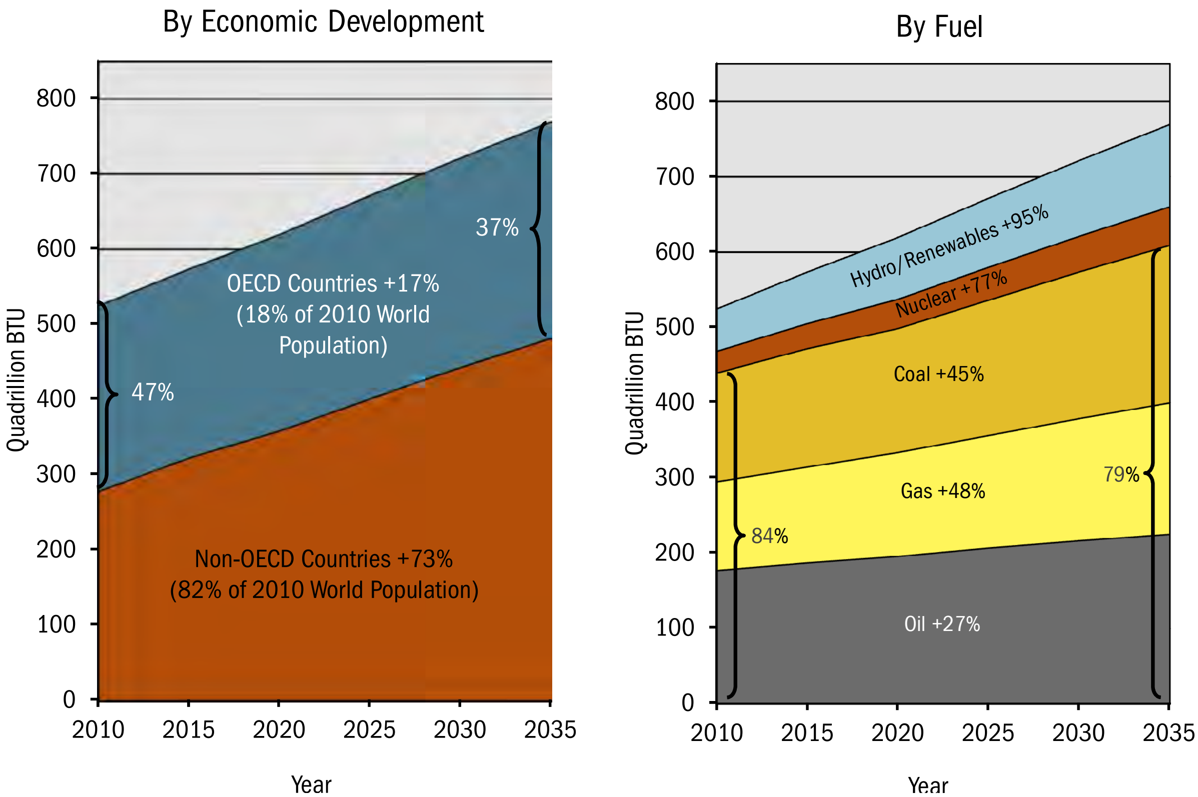

Figure 21. World energy consumption forecast by economic development and fuel, 2010-2035 (EIA Reference Case, 2011).[28]

World energy consumption is forecast to grow 47% from 2010 to 2035, or 1.6% per year. The OECD countries' energy consumption is forecast to grow 17%, although their share of world energy consumption would decline from 47% to 37%. Consumption of fossil fuels is also forecast to grow significantly, although their total share of world energy consumption would decline from 84% to 79%.

As the world's largest energy source and the premier transportation fuel, oil is a case in point. Each year overall oil production will decline without investment in finding and developing new fields and investment in maintenance of existing fields. In 2008, the International Energy Agency (IEA) investigated the decline rates of 800 of the world's largest oil fields. They determined the following:

[28] Data from EIA International Energy Outlook, reference case, September, 2011, http://www.eia.gov/forecasts/ieo/.

> *For this sample, the observed post-peak decline rate averaged across all fields, weighted by their production over their whole lives, was found to be 5.1%. Decline rates are lowest for the biggest fields: they average 3.4% for super-giant fields, 6.5% for giant fields and 10.4% for large fields.*[29]

They further suggested that decline rates will increase going forward. This is a result of the fact that the discovery of super-giant and giant fields is largely behind us, and we will have to rely more and more on smaller, faster depleting fields in the future.

The latest median forecast for world petroleum liquids production of the IEA (termed the "New Policies Scenario") is illustrated in Figure 22, which projects a decline of nearly two-thirds for all fields producing in 2011.[30] This projection suggests that overall crude oil production will decline slightly over the period to 2035, even with the development of 39.4 mbd of new production capacity from discovered and undiscovered fields (the equivalent of four Saudi Arabias' worth of new production). The balance of the projected 18.7 percent increase in world petroleum liquids supply in this projection, to 104.2 mbd in 2035, is provided by natural gas liquids, unconventional oil, biofuels and refinery gains.

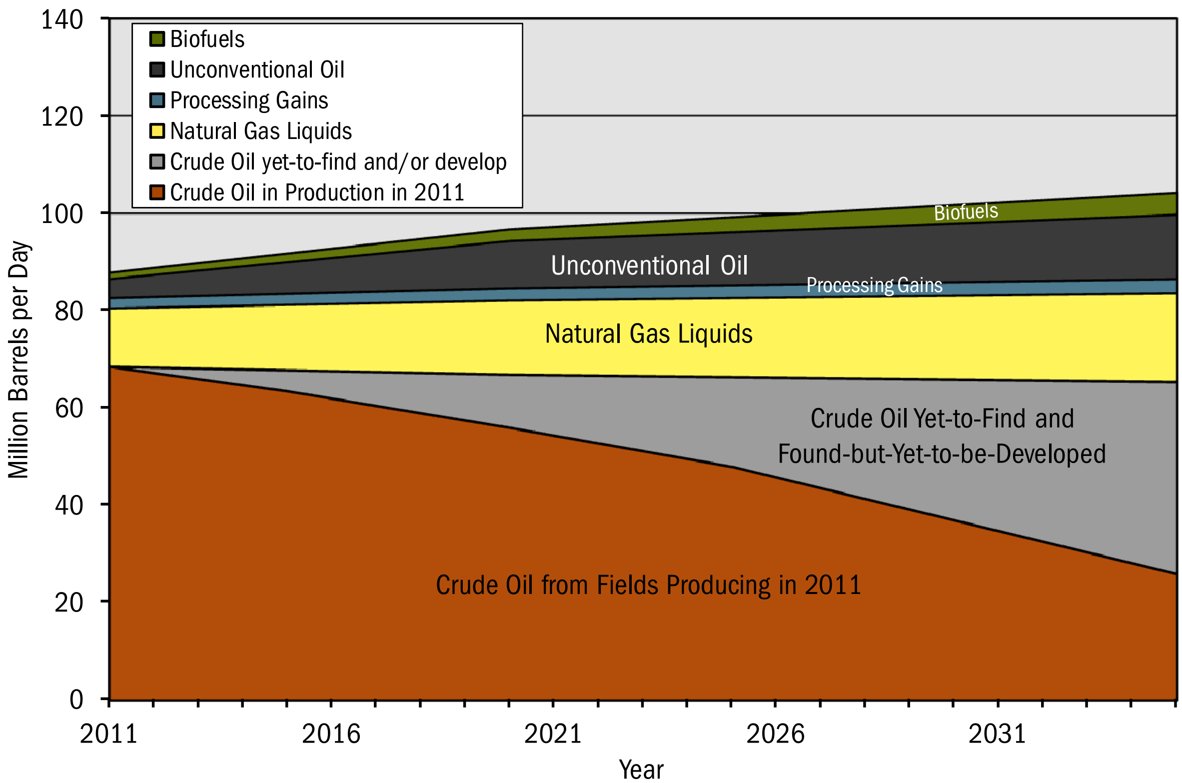

Figure 22. World oil production forecast, 2011-2035 (IEA New Policies Scenario, 2012).[31]

Nearly two-thirds, or 39.4 mbd, of current conventional crude oil production must be replaced with new production by 2035.

[29] IEA, World Energy Outlook 2008, page 43, http://www.iea.org/textbase/nppdf/free/2008/weo2008.pdf.

[30] IEA, World Energy Outlook 2012, Table 3.4, http://www.worldenergyoutlook.org/publications/weo-2012/#d.en.26099.

[31] Data from IEA, World Energy Outlook 2012, Table 3.4 and Figure 3.15, http://www.worldenergyoutlook.org/publications/weo-2011/).

This is a tall order, which the IEA says can be achieved only by spending $8.9 trillion on exploration and development in the upstream oil sector (with an additional $1.1 trillion on transport and refining).[32] Projected 2012 upstream oil and gas expenditures of $614 billion represents a level five times higher than in 2000 (in nominal dollars – in inflation adjusted dollars costs increased two and one half times). The IEA's suggestion that these costs will not escalate further over the next 23 years, as assumed in its $10 trillion upstream oil forecast, seems wishful thinking indeed.

The United States Department of Energy's EIA is more bullish on future oil production than the IEA, as illustrated in Figure 23. The EIA's reference case projection indicates world oil production will rise 31 percent to 112.2 mbd by 2035. Unconventional oil, including tar sands, extra heavy oil, coal-to-liquids, gas-to-liquids, oil shale, and biofuels are projected to provide 12 percent of this total, or 13.1 mbd by 2035.

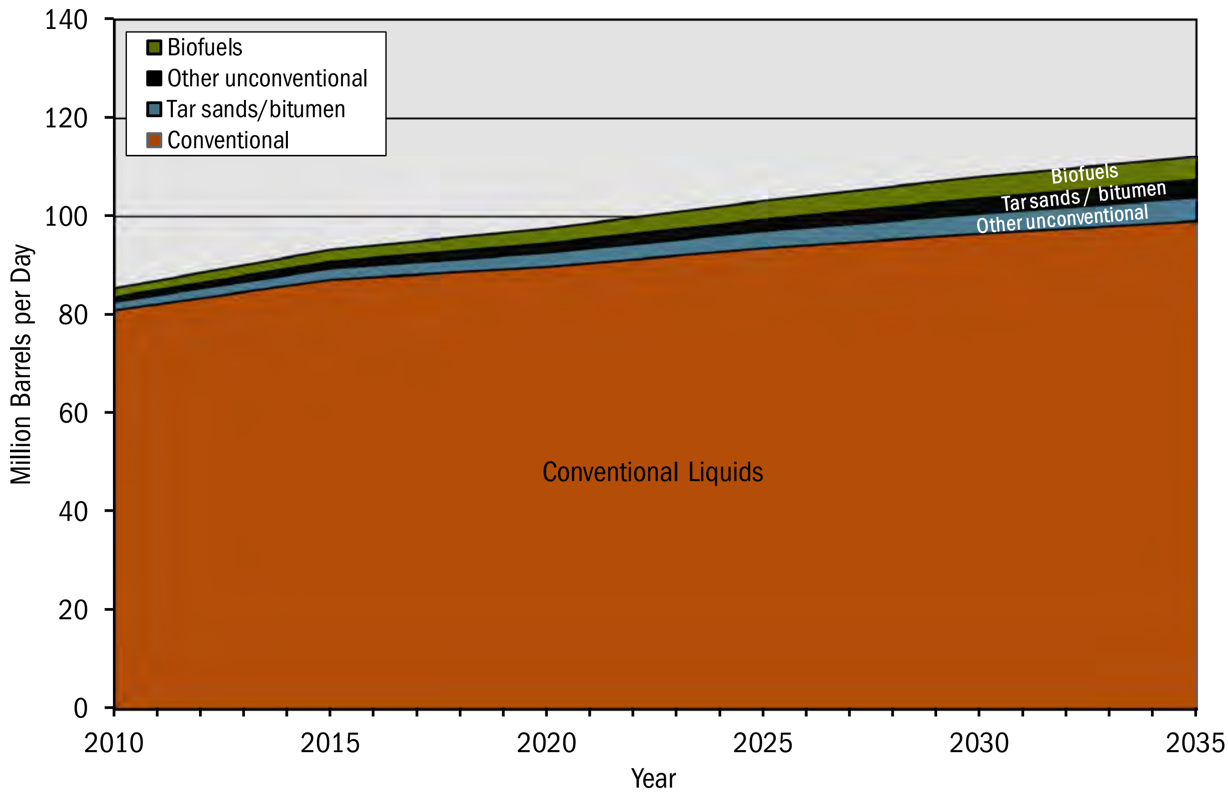

Figure 23. World oil production forecast, 2010-2035 (EIA Reference Case, 2011).[33]
"Conventional" includes refinery gains and natural gas liquids as well as tight oil. "Other unconventional" includes extra heavy oil, coal-to-liquids, gas-to-liquids, and oil shale.

[32] IEA, World Energy Outlook 2012, Table 3.8, http://www.worldenergyoutlook.org/publications/weo-2012/#d.en.26099.
[33] Data from EIA, 2011, Reference Case, http://www.eia.gov/forecasts/ieo/excel/appe_tables.xls.

The EIA hedges its bets by providing five individual projections for world oil production, all of which indicate higher oil production than its reference case except for the "traditional high oil price" case, in which production rises only 26 percent to 107.4 mbd (Figure 24). The most aggressive projection, the "traditional low oil price" case, suggests production could grow by 53 percent to 131.5 mbd by 2035. Unconventional oil is projected to grow to 19.2 mbd and comprise as much as 18 percent of production in the most aggressive "high oil price" cases by 2035.

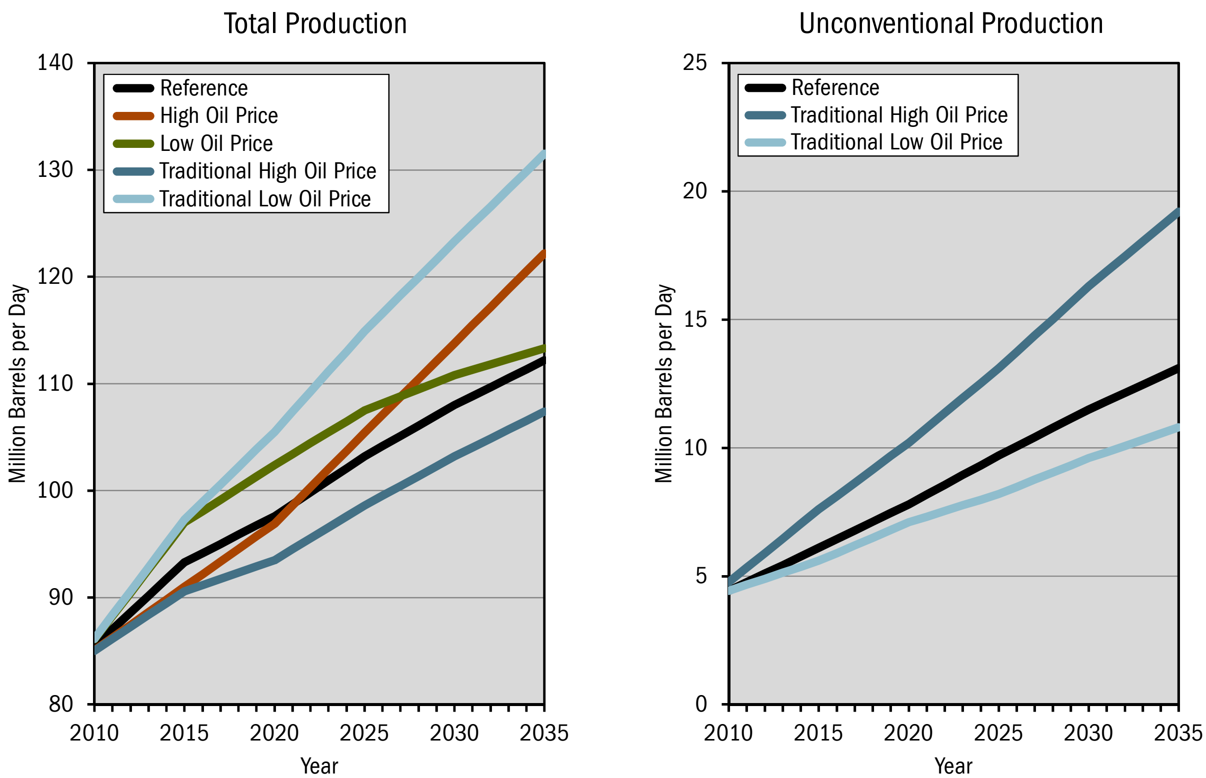

Figure 24. World total and unconventional oil production forecasts in five cases, 2010-2035 (EIA, 2011).[34]

"Unconventional production" includes tar sands, extra heavy oil, coal-to-liquids, gas-to-liquids, and oil shale. In the case of unconventional oil the "high oil price" and "traditional high oil price" cases are identical, as are the low oil price cases.

[34] Data from EIA, 2011, Reference Case.

How accurate are such forecasts, and what is the track record of previous forecasts? Figure 25 illustrates twelve EIA forecasts for world oil production going back to 2000. Compared to actual 2011 production, these projections invariably over estimated world oil production levels. The 2002 projection, for example, overestimated 2011 production by 13 percent, or 11 mbd—and that was only nine years out. In part this is a result of the fact that these are demand-driven projections based on the assumption of continual growth in GDP and the corresponding requirement for energy to fuel that demand growth. The actual geological limits and capital requirements to achieve the projected production growth are less of a consideration. Nonetheless, EIA projections are a fundamental input into energy policy considerations for the United States and many other countries.

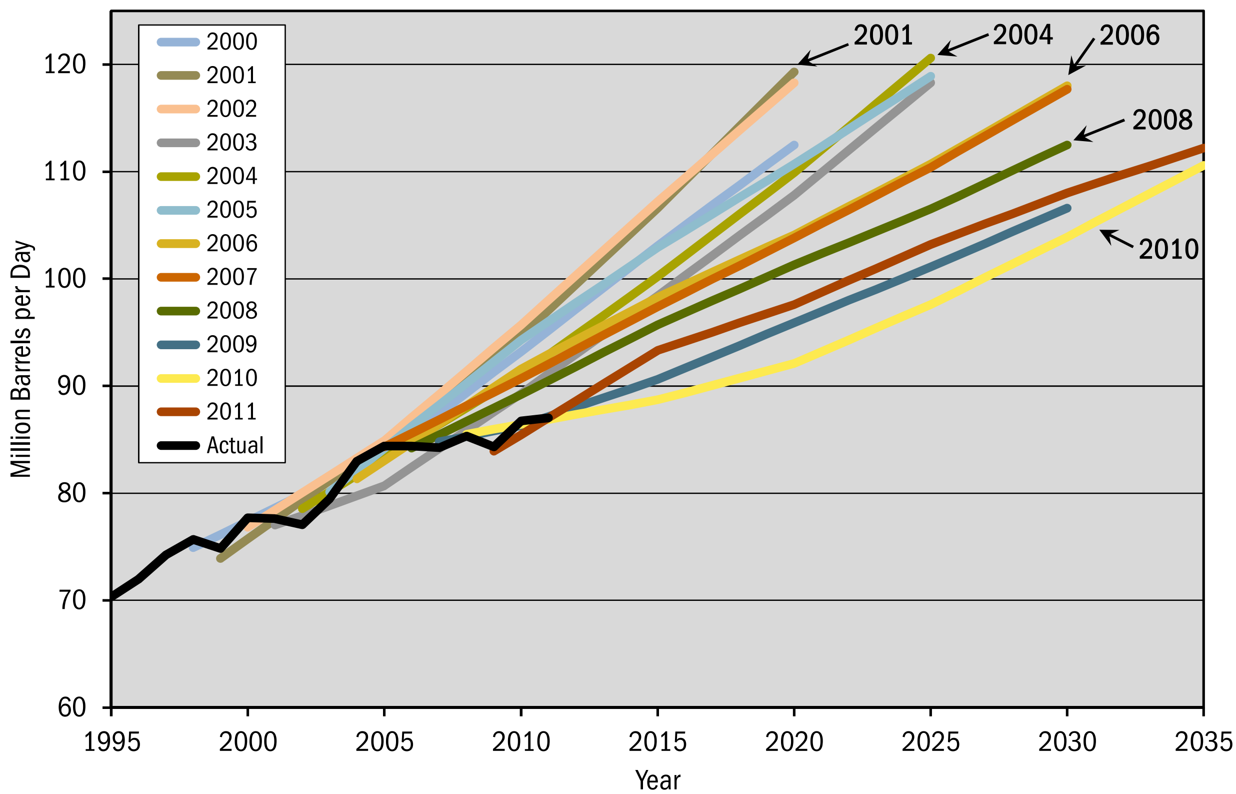

Figure 25. World oil production EIA 2000-2011 forecasts to 2035, compared to actual production, 1995-2011.[35]

Most cases invariably overestimated actual 2011 production.

[35] Data from EIA, 2011, and earlier editions available at http://www.eia.gov/forecasts/ieo/ ; Actual production from EIA.

The IEA, in fact, has indicated in its World Energy Outlook 2012 that conventional crude oil is now past peak production and, even with the development of new production equivalent to two-thirds of current production, will decline slightly through 2035. Future demand growth in the IEA's forecast must be met by unconventional oil, biofuels and natural gas liquids.

Forecasts of future oil production growth tend to be optimistic when made by governments requiring long term GDP growth (or by multinational oil companies and oil producing organizations whose longevity depends on growing oil production). More pessimistic forecasts of a nearer term peak in oil production are generally the realm of independent analysts that have no particular vested interest in one outcome over another.

Indeed, in 2009 the United Kingdom Energy Research Centre (UKERC) released a report on global oil depletion in which they reviewed models of future oil production by many organizations.[36] The main conclusions of this report were:

- On the current evidence, a peak in the global production of conventional oil before 2030 appears very likely and a peak before 2020 appears probable.
- A peak before 2030 is likely also for global "all-oil" production (covering conventional oil, [natural gas liquids], heavy oils, and oil from tar sands).
- Less well understood is the rate that alternative liquid fuels might be brought on-stream, where these include oil from shale, [gas-to-liquids, coal-to-liquids], and biofuels.

Nevertheless, rosy forecasts also do come from independent sources: In June 2012, a highly optimistic forecast for future world oil production published by Leonardo Maugeri of the Harvard Kennedy School Belfer Center for Science and International Affairs suggests that world oil production capacity, exclusive of biofuels, could grow to 110.6 mbd by 2020.[37] This compares to the IEA production forecast of 94.3 mbd by 2020 (New Policies Scenario) and the EIA forecast of 94.6 mbd (reference case). Although Maugeri was forecasting production capacity, not actual production, it is highly unlikely that this much capacity would be developed unless most of it was used (world surplus production capacity was about 2.3 mbd in the first quarter of 2012). The Maugeri forecast has been discredited by several authors, mainly on the grounds that Maugeri underestimated the depletion rate of existing fields and overestimated the contributions of production from countries such as Iraq and tight oil fields in the United States.[38,39,40] Nonetheless, despite its obvious shortfalls, this report has been widely cited and is a foundation of the Republican Party's energy policy.[41]

36 United Kingdom Energy Research Centre Technical Report 7, Comparison of Global Supply Forecasts, http://www.ukerc.ac.uk/support/tiki-download_file.php?fileId=291

37 Leonardo Maugeri, *Oil: The Next Revolution*, June, 2012, http://belfercenter.ksg.harvard.edu/publication/22144/oil.html.

38 Steve Sorrell, "Response to Leonardo Maugeri's Decline Rate Assumptions in *Oil: The Next Revolution*," July 2012, http://www.theoildrum.com/node/9327.

39 James Hamilton, "Maugeri on Peak Oil," July 19, 2012, http://www.resilience.org/stories/2012-07-19/maugeri-peak-oil.

40 Chris Nelder, "Is Peak Oil Dead?," July 24, 2012, http://ftalphaville.ft.com/blog/2012/07/24/1094111/is-peak-oil-dead/.

41 Romney for President, "The Romney Plan for a Stronger Middle Class: Energy Independence," August 22, 2012, http://www.ourenergypolicy.org/wp-content/uploads/2012/08/energy_policy_white_paper.pdf.

The prognosis for growth in global natural gas production has been buoyed by the development of shale gas in the United States and the assumption that shale gas production technology will unlock new reserves worldwide. Figure 26 is the latest forecast of world gas production by the EIA through 2035. Total growth in production over the period ranges from 34 to 59 percent over 2010 levels, with a reference case of 48 percent growth. An extensive analysis of shale gas is presented in a later section.

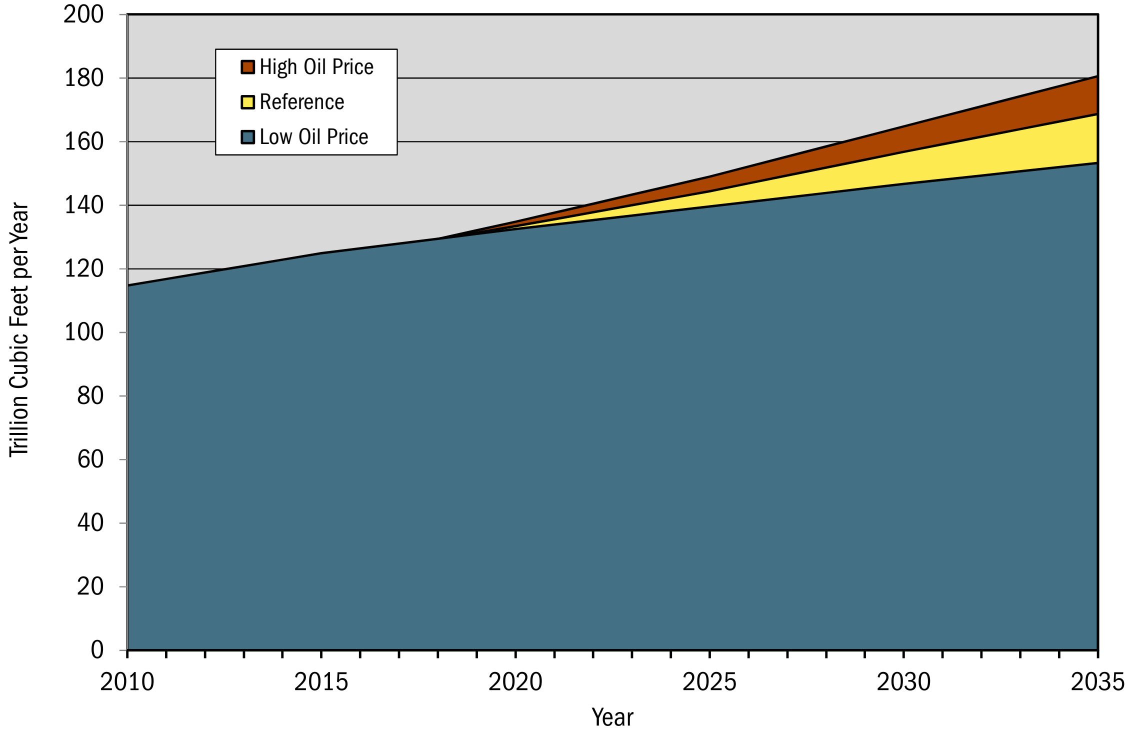

Figure 26. World natural gas production forecast, 2010-2035, in three cases (EIA, 2011).[42]

The reference case indicates 48 percent growth in natural gas production over 2010 levels.

[42] Data from EIA International Energy Outlook 2011.

United States

Growth in energy consumption in the United States is forecast by the EIA to be gradual through 2040 as illustrated in Figure 27. Total consumption is forecast to grow by 9 percent over the period with fossil fuel comprising 80 percent of the 2040 total (down from 84 percent in 2010), of which 61 percent is projected to be provided by oil and gas. Renewable energy, comprising hydropower, biomass, wind, solar, and geothermal, is projected to provide 11 percent of total consumption in 2040.

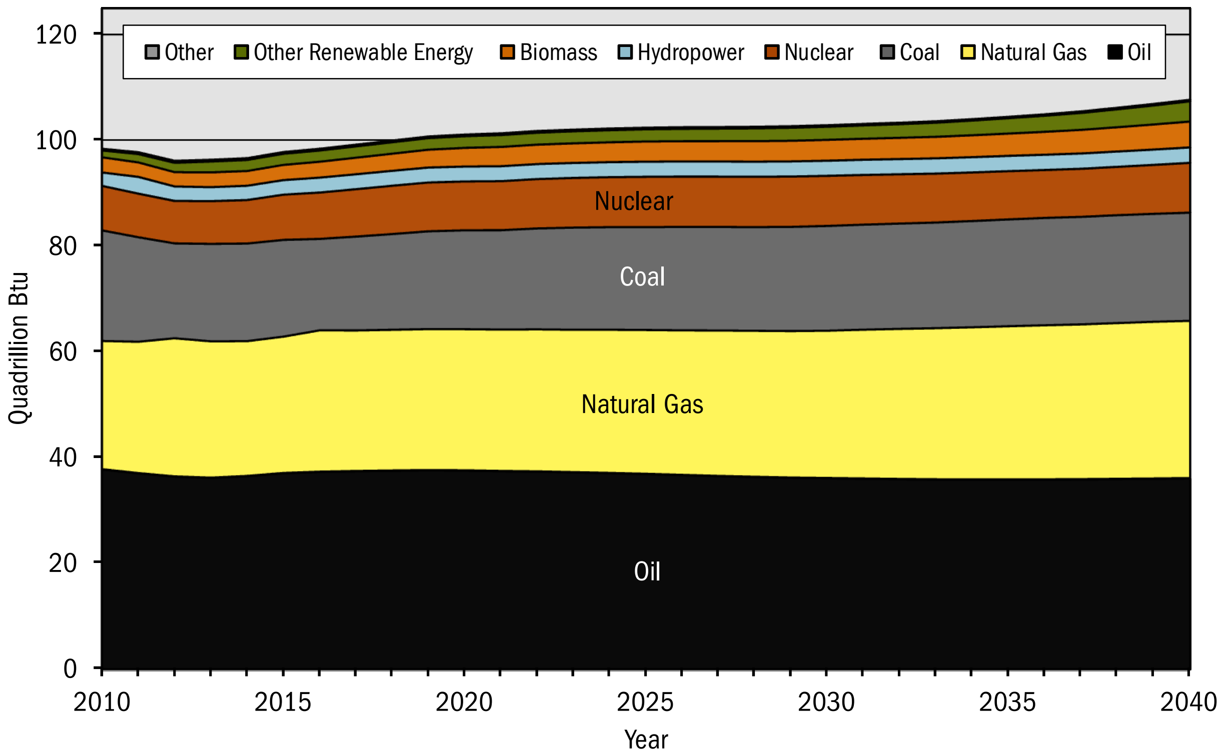

Figure 27. U.S. energy consumption forecasts by source, 2010-2040 (EIA Reference Case, 2013).[43]

Fossil fuels are projected to provide 80 percent of 2040 consumption of which oil and gas comprise 61 percent.

[43] Data from EIA Annual Energy Outlook 2013, Table 1, http://www.eia.gov/forecasts/aeo/er/excel/yearbyyear.xlsx.

Oil

Figure 28 illustrates the EIA's reference case supply forecast for petroleum liquids in the United States through 2040. Total consumption is projected to decline by one percent by 2040, when 64 percent would be provided by domestic sources and the balance by imports. Domestic crude oil production is forecast to grow by twelve percent over the period but reach a peak in production in 2019 and provide only 32 percent of supply in 2040. Growth in domestic crude oil production is largely a result of the assumptions that there will be significant new production from shale/tight oil and that production can be maintained and even grow somewhat in deepwater Gulf of Mexico. Biofuels are forecast to grow by 65 percent to reach 7.5 percent of total supply (a radical reduction from the previous EIA forecast released in mid-2012 of 176 percent growth and 12 percent of total supply by 2035). Natural gas liquids are forecast to grow by 41 percent as a result of rapidly expanded shale gas production, reaching 15 percent of supply. The development of some coal-to-liquids and gas-to-liquids production capacity is also assumed over the period rising to slightly more than one percent of supply by 2040.

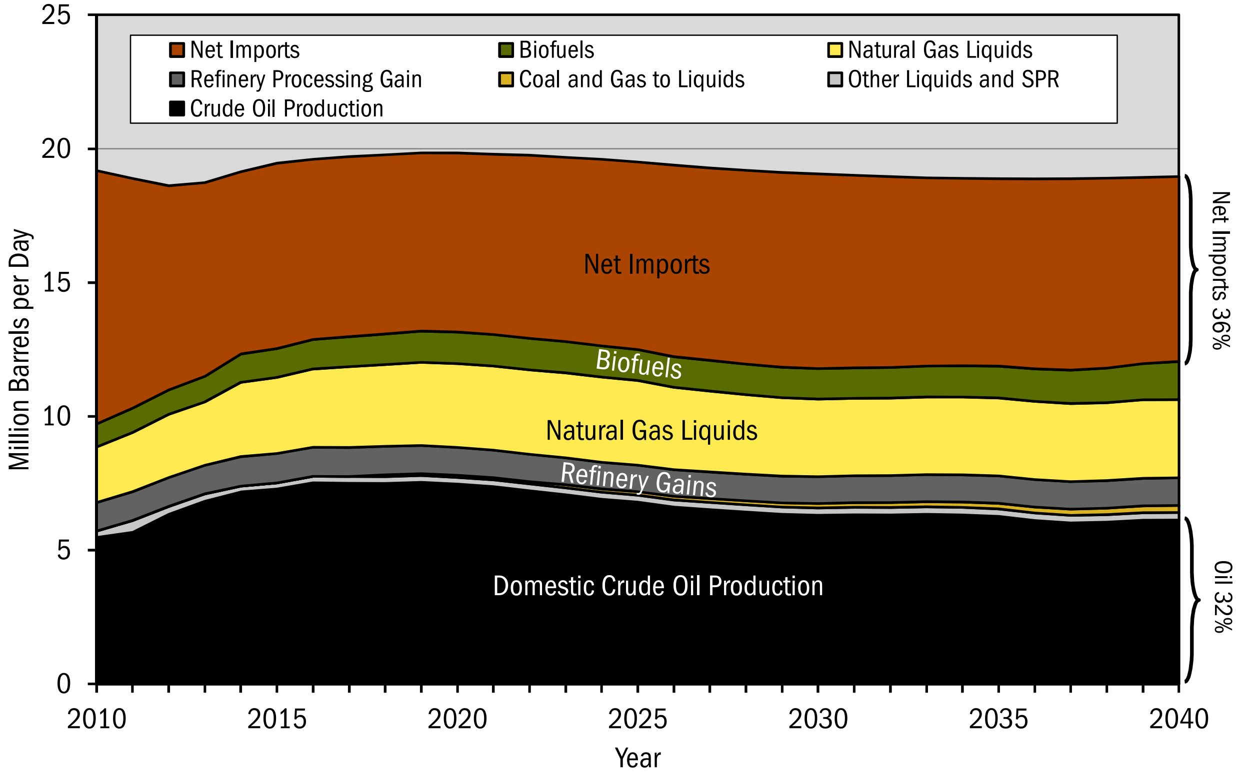

Figure 28. U.S. petroleum liquids supply forecast by source, 2010-2040 (EIA Reference Case, 2013).[44]

Although net imports of oil decrease from 49 percent of supply in 2010 to 36 percent in 2040 in this projection, the United States will remain heavily dependent on oil imports.

[44] Data from EIA Annual Energy Outlook 2013 early release, Table 11, http://www.eia.gov/forecasts/aeo/er/excel/yearbyyear.xlsx.

The fact that imports are projected to meet 36 percent of 2040 supply belies the current rhetoric in some circles of the United States soon becoming "energy independent." Given that the EIA's forecasts have been demonstrated earlier to be optimistic (see Figure 25), the situation with respect to future import requirements is likely understated in this projection (in fact, net imports would be 40 percent of total supply in 2040 if the assumption of ramped up exports of refined petroleum products after 2030 does not occur).

Much of the rhetoric on future oil production growth in the United States and "energy independence" has been focused on the recent growth of shale/tight oil production in the Bakken/Three Forks play of North Dakota and Montana, and the Eagle Ford play of southern Texas. Figure 29 illustrates the EIA's reference case for United States crude oil production by source. This assumes rapid growth in production from shale/tight oil, from enhanced oil recovery in older fields through injection of carbon dioxide, through some growth and maintenance of production levels in the deepwater Gulf of Mexico, and through growth in production off the West Coast. Despite these assumptions, the United States is still forecast to reach peak production quite soon, by the end of this decade (this does, however, represent a dramatic turnaround from the terminal decline trajectory United States oil production was on as recently as 2008).

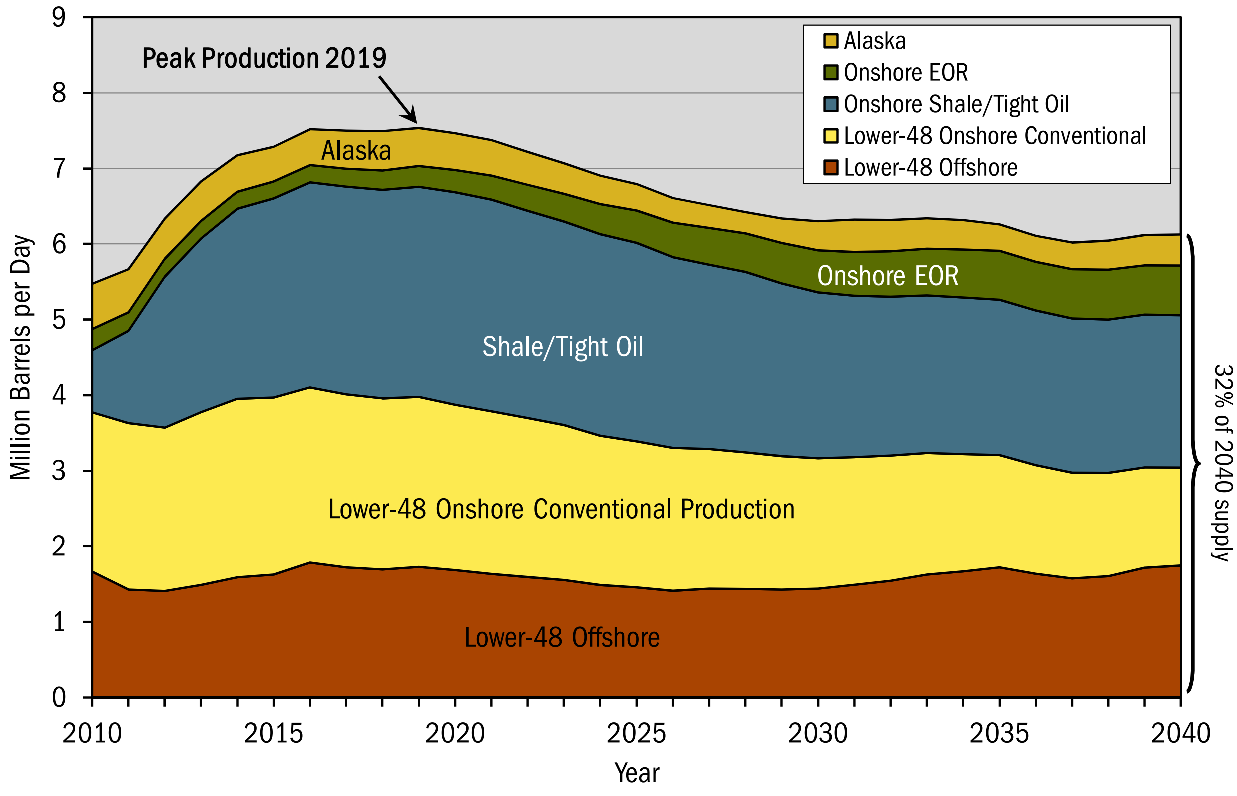

Figure 29. U.S. crude oil production forecast by source, 2010-2040 (EIA Reference Case 2013).[45]

Shale/tight oil production and enhanced oil recovery in old fields through CO_2 injection are the main sources of growth. Even with these assumptions, peak production is reached in 2019, and total U.S. oil production makes up only 32% of the total U.S. oil supply by 2040.

[45] Data from EIA Annual Energy Outlook 2013 early release, Table 14.

The growth in shale/tight oil production in this projection is very aggressive, requiring the consumption of 26 billion barrels, or 78 percent, of the EIA's estimated unproved technically recoverable shale/tight oil resource by 2040.[46] The likelihood of this happening is remote, as discussed in the subsequent section on shale/tight oil. Overall, this projection requires the recovery of 75 billion barrels by 2040, which is three times the proved crude oil reserves of the U.S. at year-end 2010.[47]

As with its world oil production projections noted earlier, the EIA maintains several additional cases of economic growth and oil prices for its forecasts. The 2012 EIA estimates are illustrated in Figure 30 along with projections for shale/tight oil for each of the cases. These are compared to the recently released 2013 EIA reference case forecast. In all of the 2012 cases, except the "Low Oil Price" case, peak United States production occurs in 2020. In the "Low Oil Price" case peak production occurs in 2016, and in the 2013 EIA reference case projection peak production occurs in 2019. In no instance is the United States close to becoming independent from imported oil in the foreseeable future.

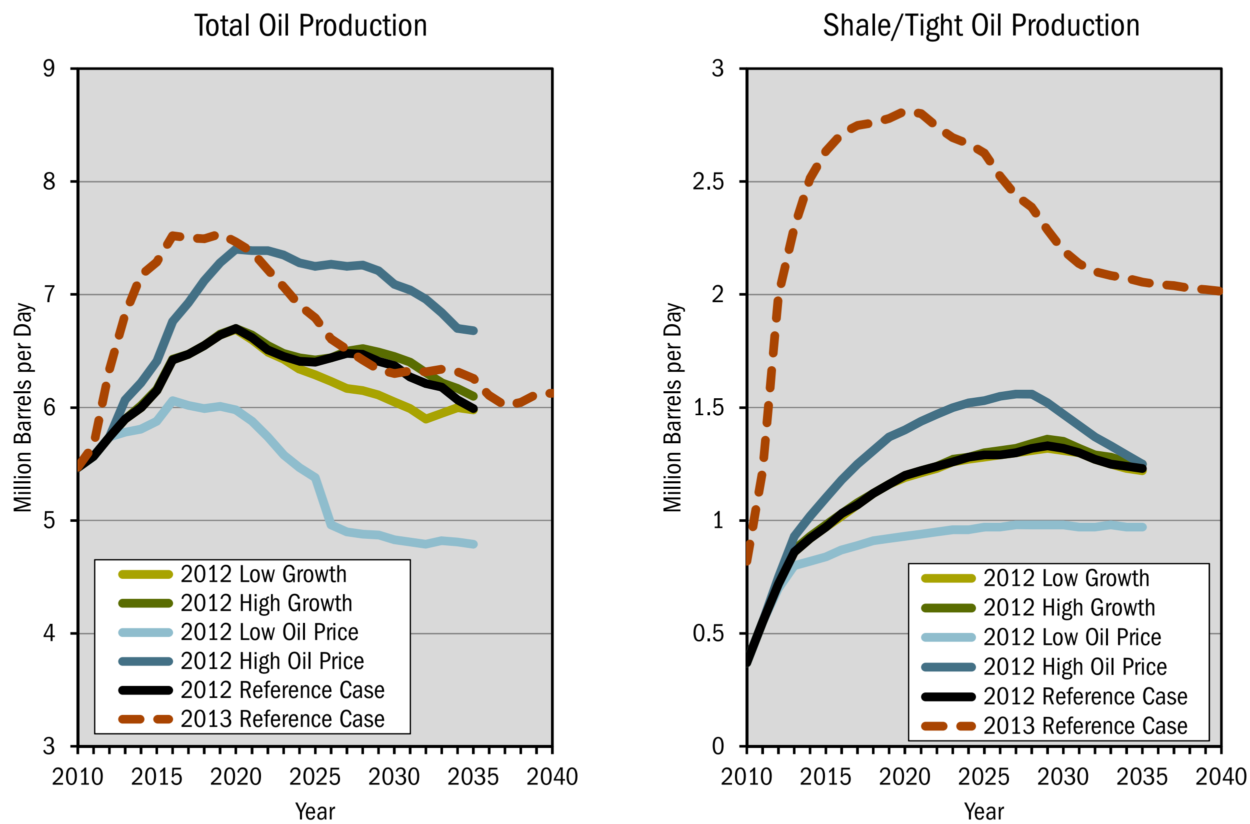

Figure 30. U.S. total oil and tight oil production EIA 2012 forecasts in five cases versus the EIA 2013 forecast, 2010-2040.

At left are the 2012 and 2013 EIA Annual Energy Outlook projections of total oil production in six economic cases from 2010 through 2040.[48] At right are tight oil (shale oil) production projections for the same forecasts.

[46] EIA, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/archive/aeo12/pdf/0383(2012).pdf.

[47] EIA, 2012, U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves, http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_4.xls.

[48] Data from EIA, Annual Energy Outlook 2012, Table 14 from each of 5 cases, http://www.eia.gov/forecasts/aeo/data_side_cases.cfm and EIA Annual Energy Outlook 2013 early release, Table 14.

The oil price assumptions in these forecasts range from a low of $58.53/barrel in 2020 and $55.36/barrel in 2035 to a high of $181.55/barrel in 2020 and $188.44/barrel in 2035 (in 2010 dollars). The reference case 2012 projection calls for an oil price of $124.44/barrel in 2020 and $137.55/barrel in 2035. The reference case 2013 projection calls for an oil price of $105.57/barrel in 2020 and $145.41/barrel in 2035 (in 2011 dollars). These price projections belie any peak in global oil production in the near term, as forecast by the aforementioned review of many organizations by the United Kingdom Energy Research Centre, and the price volatility such a peak would represent (for example, oil hit $147/barrel in 2008 after global oil production essentially stalled for two years at 84-85 mbd).

The rising trend and recent volatility of oil prices coupled with the forecasts of oil prices and U.S. production in the EIA's 2013 reference case is illustrated in Figure 31.

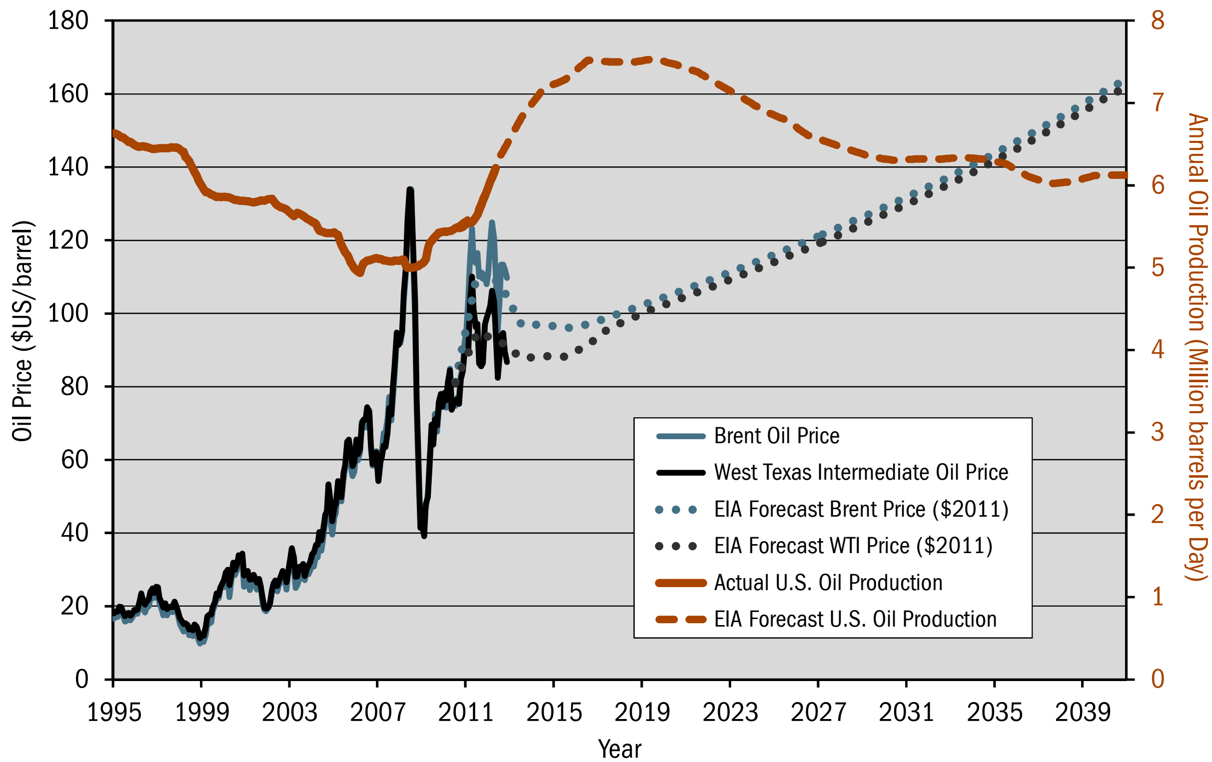

Figure 31. U.S. oil prices and production, 1995-2012, versus EIA 2013 forecasts to 2040.[49]

The large variability even in near term projections of crude oil supply from EIA forecasts only six months apart points to their lack of veracity. They are generally optimistic, as pointed out for its world oil production forecasts in Figure 25, and assume continual replacement of produced reserves notwithstanding the generally mature and highly explored nature of U.S. sedimentary basins. The projected production growth trend illustrated in Figure 31 is counterintuitive, as oil prices are projected to fall as U.S. oil production rises over the next four years and production falls thereafter as oil prices

[49] Forecast data from EIA, Annual Energy Outlook 2013 early release; oil production from http://www.eia.gov/dnav/pet/xls/pet_crd_crpdn_adc_mbblpd_m.xls ; oil prices from http://www.indexmundi.com/commodities.

rise. Nonetheless, compared to some private sector forecasts from the financial community and elsewhere, the EIA forecasts are conservative.

Several recent reports have been much more bullish on American oil production prospects than the EIA. One, by Maugeri (2012), has been discussed earlier with respect to world oil production.[50] Maugeri projects production growth to 4.17 mbd from shale/tight oil plays by 2020, versus 2.81 mbd in the EIA 2013 reference case, and an overall net increase in United States production of 3.5 mbd by 2020 (versus 2 mbd for the EIA 2013 reference case). The optimistic assumptions in this report have been discredited by Sorrell[51], Hamilton[52] and Nelder[53], among others.

Citigroup also published a very bullish report in 2012[54] suggesting United States liquids production (crude oil, natural gas liquids, and biofuels) could grow by 73 percent to 15.6 mbd by 2020. Compared to the EIA's 2013 reference case projections, the Citigroup report projects shale /tight oil to grow to 3 mbd by 2020, versus 2.81 mbd for the EIA, deepwater oil to grow to 3.8 mbd versus 1.69 mbd for the EIA, Alaska to grow to 1.1 mbd versus 0.49 mbd for the EIA, natural gas liquids to grow to 3.8 mbd versus 3.13 mbd for the EIA, and biofuels to grow to 1.5 mbd versus 1.18 mbd for the EIA. The overly optimistic assumptions of this report have been reviewed in depth and discredited by Summers.[55]

Perhaps the most egregious report is by Raymond James[56], who suggested that crude production will rise by 75 percent by 2020 (exclusive of natural gas liquids and biofuels), and that coupled with falling demand the United States will become "oil import free" by 2020. The authors offer little evidence other than "trust us."

The wholesale adoption of these very rosy views, which are not backed up by much more than wishful thinking and are wildly more bullish than even the historically rosy views of the EIA, mark a dangerous course for United States energy policy (notwithstanding this, all three of these reports were endorsed by the 2012 Republican presidential campaign.[57]

Most recently, the IEA in its recent World Energy Outlook 2012 attracted widespread media attention with its claim that the U.S. would soon be producing more oil than Saudi Arabia.[58] This assumed that shale/tight oil production in the U.S. would grow to 3.1 mbd by 2020 and included rapidly growing natural gas liquids production as "oil", which makes it an "apples to oranges" comparison. Even if the U.S. meets the EIA 2013 reference case crude oil production forecast it will still be significantly below Saudi Arabia's production over the period to 2040.[59] And even assuming these projections can be met, the U.S. will still be importing 36 percent of its petroleum liquids needs in 2040 (Figure 28).

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50 Leonardo Maugeri, *Oil: The Next Revolution*, June, 2012, http://belfercenter.ksg.harvard.edu/publication/22144/oil.html.

51 Steve Sorrell, "Response to Leonardo Maugeri's Decline Rate Assumptions in *Oil: The Next Revolution*," July 2012, http://www.theoildrum.com/node/9327.

52 James Hamilton, "Maugeri on Peak Oil," July 19, 2012, http://www.resilience.org/stories/2012-07-19/maugeri-peak-oil.

53 Chris Nelder, "Is Peak Oil Dead?," July 24, 2012, http://ftalphaville.ft.com/blog/2012/07/24/1094111/is-peak-oil-dead/.

54 Morse et al., *Energy 2020: North America the new Middle East?*, 2012, http://fa.smithbarney.com/public/projectfiles/ce1d2d99-c133-4343-8ad0-43aa1da63cc2.pdf.

55 David Summers, "A review of the Citigroup prediction on U.S. energy," April 1, 2012, http://www.theoildrum.com/node/9079.

56 J.M. Adkins and Pavel Molchanov, "Yes, Mr. President, We Believe We Can Drill Our Way Out of This Problem," Raymond James, April 2, 2012, http://www.raymondjames.com/AdvisorSitesFiles/PublicSites/silentKthoughts/files/Yes_Mr_President.pdf.

57 Romney for President, "The Romney Plan for a Stronger Middle Class: Energy Independence," August 22, 2012.

58 IEA, World Energy Outlook 2012, http://www.worldenergyoutlook.org/.

59 EIA, Annual Energy Outlook 2013 early release.

Natural Gas

Figure 32 illustrates the EIA's reference case forecast for United States natural gas supply through 2035 by source. This is a very aggressive forecast even compared to the EIA's most recent earlier projection released in June, 2012. Overall U.S. gas production is projected to grow by 47 percent through 2035, up from 29 percent in its forecast just six months earlier, and by 55 percent through 2040. Fifty percent of 2040 production is projected to come from shale gas, with a further 23 percent from tight gas, both of which rely on controversial hydraulic-fracturing technology for production. The Alaska gas pipeline is projected to be built and online by 2024 despite estimates of historically low gas prices (the EIA's earlier forecast did not foresee the Alaska gas pipeline before 2035). Although conventional sources of onshore gas are projected to decline, with only slight growth in offshore production, projections of rapid growth in unconventional gas production dominates the forecast. The U.S. is projected to become a net exporter of gas by 2020 and to export 11 percent of production by 2040.

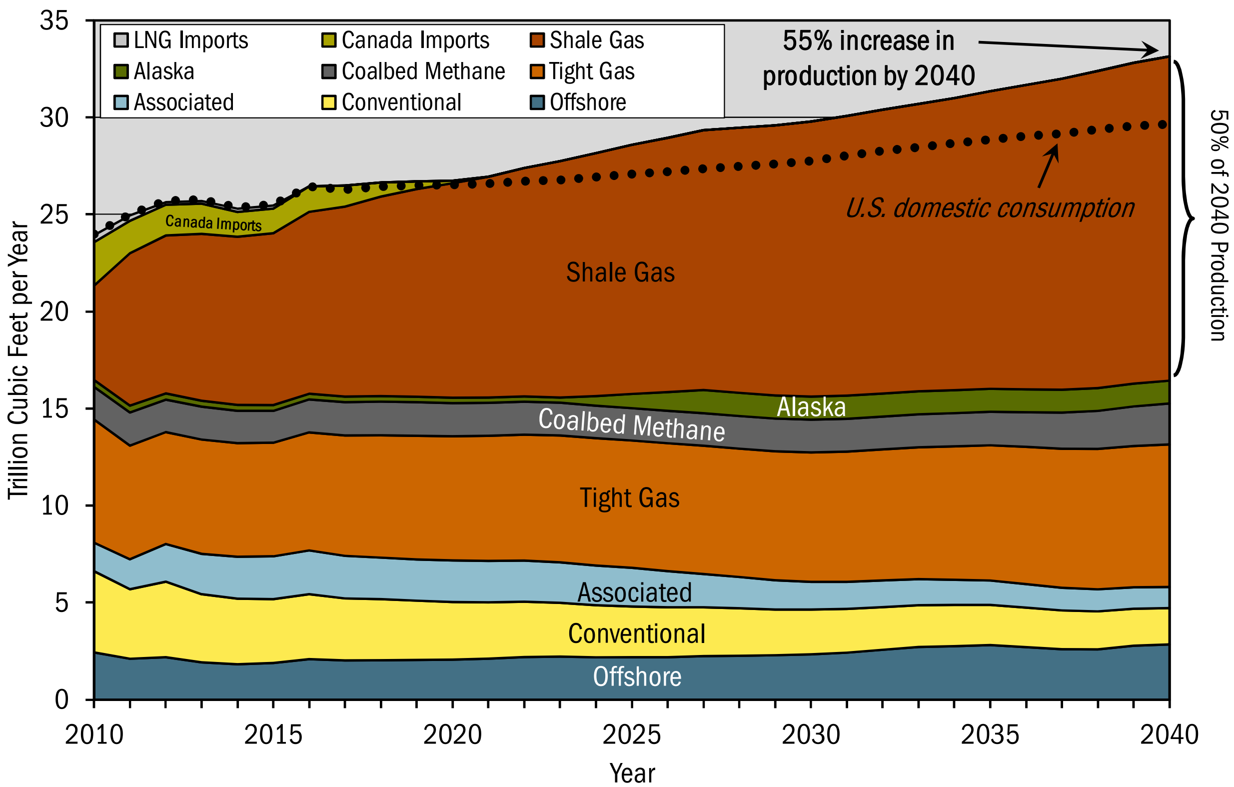

Figure 32. U.S. natural gas supply by source, 2010-2040 (EIA Reference Case, 2013).[60]
Shale gas accounts for 50 percent of production in 2040.

[60] Data from EIA Annual Energy Outlook 2013 early release, Tables 13 and 14.

There is much controversy associated with shale gas production, over both its environmental impacts and its economic viability. The ability of shale gas to fill the production gap left by declining production from other sources is questionable. An analysis of shale gas production and its prospects for offsetting declines in other sources of natural gas is provided in a later section.

The EIA offers several scenarios based on different economic growth and oil price cases in its projections of natural gas production in the United States. These are illustrated for both total production and shale gas in Figure 33. In all cases the future of United States gas supply growth is projected to lie predominantly with shale gas.

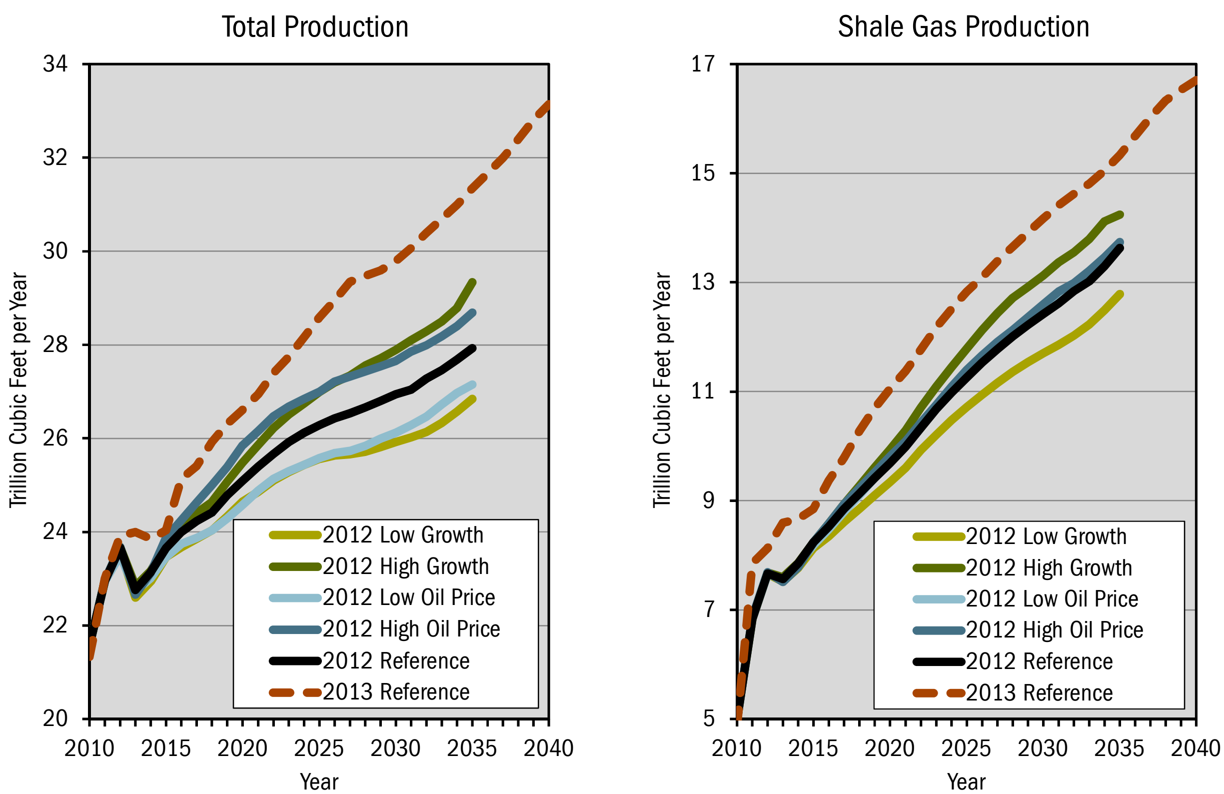

Figure 33. U.S. total gas and shale gas production EIA 2012 forecasts in five cases versus the EIA 2013 forecast, 2010-2040.

At left are the 2012 and 2013 EIA Annual Energy Outlook projections of total natural gas production in six economic cases from 2010 through 2040.[61] At right are shale gas production projections for the same forecasts.[62]

[61] Data from EIA, Annual Energy Outlook 2012, Table 14 from each of 5 cases, http://www.eia.gov/forecasts/aeo/data_side_cases.cfm.

[62] Data from EIA Annual Energy Outlook 2013, Table 14.

The natural gas price assumptions in these forecasts range from a low of $4.23/MMbtu in 2020 and $6.60/MMbtu in 2035 to a high of $4.89/MMbtu in 2020 and $7.58/MMbtu in 2035 (in 2010 dollars). The EIA 2013 reference case projection calls for a natural gas price of $4.13/MMbtu in 2020 and $6.32/MMbtu in 2035 (in 2011 dollars). This projection is a disaster scenario for the profitability of shale gas producers according to a detailed study by geologist Arthur Berman[63], who projects current average full cycle breakeven shale gas prices of $8.31/MMbtu to $8.78/MMbtu. The cash crunch with shale gas producers is already becoming evident.[64]

Figure 34 illustrates historical gas prices in the U.S., Europe and southeast Asia, and the EIA 2013 reference case price projections through 2040. Also shown are actual and projected U.S. gas production. Gas prices in the past have been volatile and reached $13/mcf as recently as June, 2008. Notwithstanding this historical volatility, the EIA projects gas prices below $6/mcf for the next two decades.

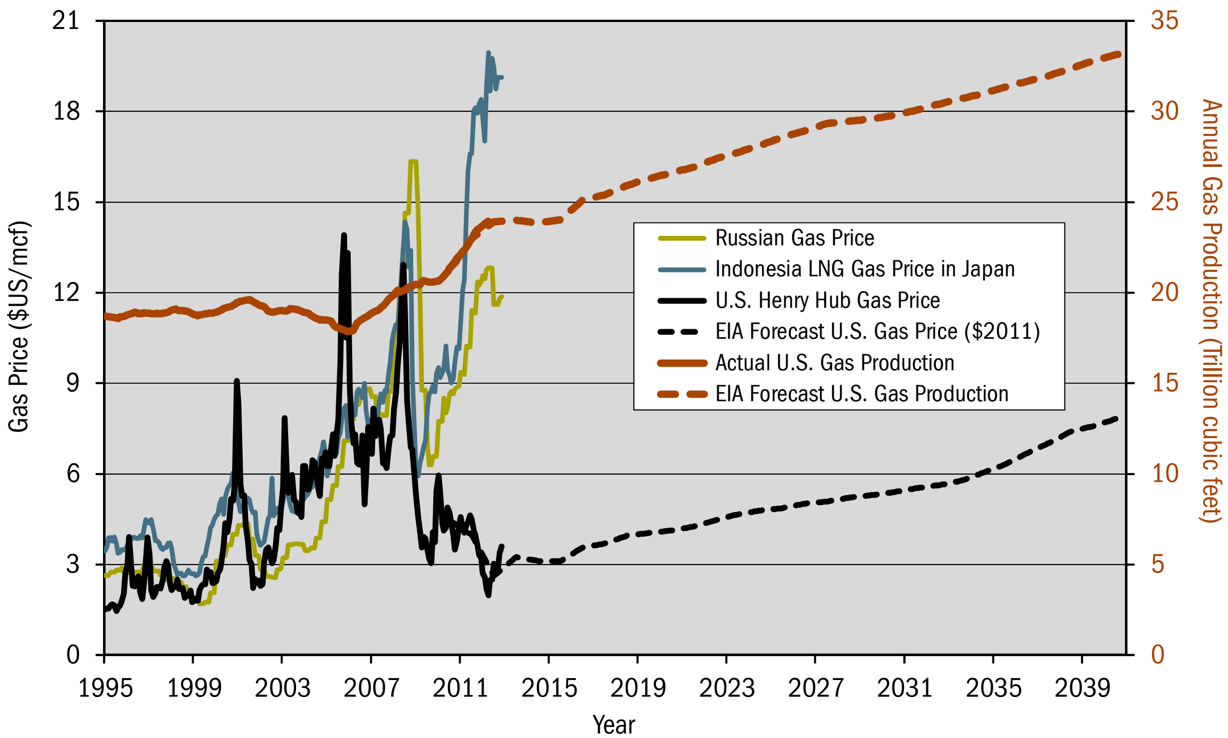

Figure 34. U.S. gas prices and production, 1995-2012, versus EIA 2013 forecasts to 2040.[65]

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63 Arthur Berman and Lynn Pittinger, "U.S. Shale Gas: Less Abundance, Higher Cost," The Oil Drum, August 5, 2011, http://www.theoildrum.com/node/8212.

64 Antoine Gara, "Shale Boom Cash Hole Goes Much Deeper Than Chesapeake Energy," September 7, 2012, Minyanville, http://www.minyanville.com/sectors/energy/articles/thestreet-HAL-chk-bhi-cam-rig/9/7/2012/id/43823.

65 Forecast data from EIA, Annual Energy Outlook 2013 early release; gas production from http://www.eia.gov/dnav/pet/xls/pet_crd_crpdn_adc_mbblpd_m.xls ; gas prices from http://www.indexmundi.com/commodities/.

The sheer volumes of gas required to meet the latest EIA production forecast when compared to current U.S. gas reserves strains credibility (Figure 32). These projections are based on a continual conversion of unproved technically recoverable resources to production at gas prices that are below the current marginal cost of production. Specifically, between 2010 and 2040, the EIA 2013 projections require:

- the overall production of 871 tcf,[66] which includes all of the current 317.6 tcf of proved gas reserves[67] plus an additional 553.4 tcf of unproved technically recoverable resources.
- the production of 382 tcf of shale gas, which is all of the current 97.4 tcf of "proved reserves" and 59 percent of the EIA's estimate of unproved technically recoverable resources.[68]
- the production of 54 tcf of coalbed methane, which is three times the current proved reserves of 17.5 tcf.
- the production of 72 tcf from the lower-48 offshore, which is five times the current proved reserves of 12.1 tcf.
- the production of 23 tcf from Alaska, which is more than double its current proved reserves of 8.9 tcf.
- the production of 340 tcf from conventional gas of the lower 48 onshore, which is nearly double the current proved reserves of 181.7 tcf.
- the export of 45 tcf of gas by 2040 at which point the U.S. would be exporting 11 percent of production.
- the drilling of 1.7 million new oil and gas wells.

This amounts to a projection of an unrestrained liquidation of U.S. gas reserves and resources which is likely to be very difficult to achieve given the mature state of exploration and development of U.S. oil and gas resources and the Law of Diminishing Returns.

[66] Data from EIA Annual Energy Outlook 2013 early release, Table 14.

[67] EIA 2012, "U.S. Crude Oil, Natural Gas, and NG Liquids Proved Reserves," http://www.eia.gov/naturalgas/crudeoilreserves/.

[68] EIA Annual Energy Outlook 2012, p58, http://www.eia.gov/forecasts/archive/aeo12/pdf/0383(2012).pdf.

The Law of Diminishing Returns is, in fact, well-illustrated in these EIA forecasts. Figure 35 illustrates the projected level of drilling required to meet the oil and gas production targets. To increase the energy provided from U.S. crude oil, natural gas liquids, and natural gas production by 41 percent through 2040, the EIA's reference case projects that the number of wells drilled annually must increase by 77 percent . This means an annual drilling rate of 76,650 wells per year in 2040 is required, a large proportion of them horizontal, multi-stage, hydraulically fractured wells.[69]

A closer look at the data reveals that the diminishing returns in the longer term are really much worse than this: the EIA projects that with only a 4 percent increase in drilling between now and 2016, production can increase 28 percent; in contrast, after 2016 drilling must increase by 71 percent by 2040 in order to increase production by only 10 percent.

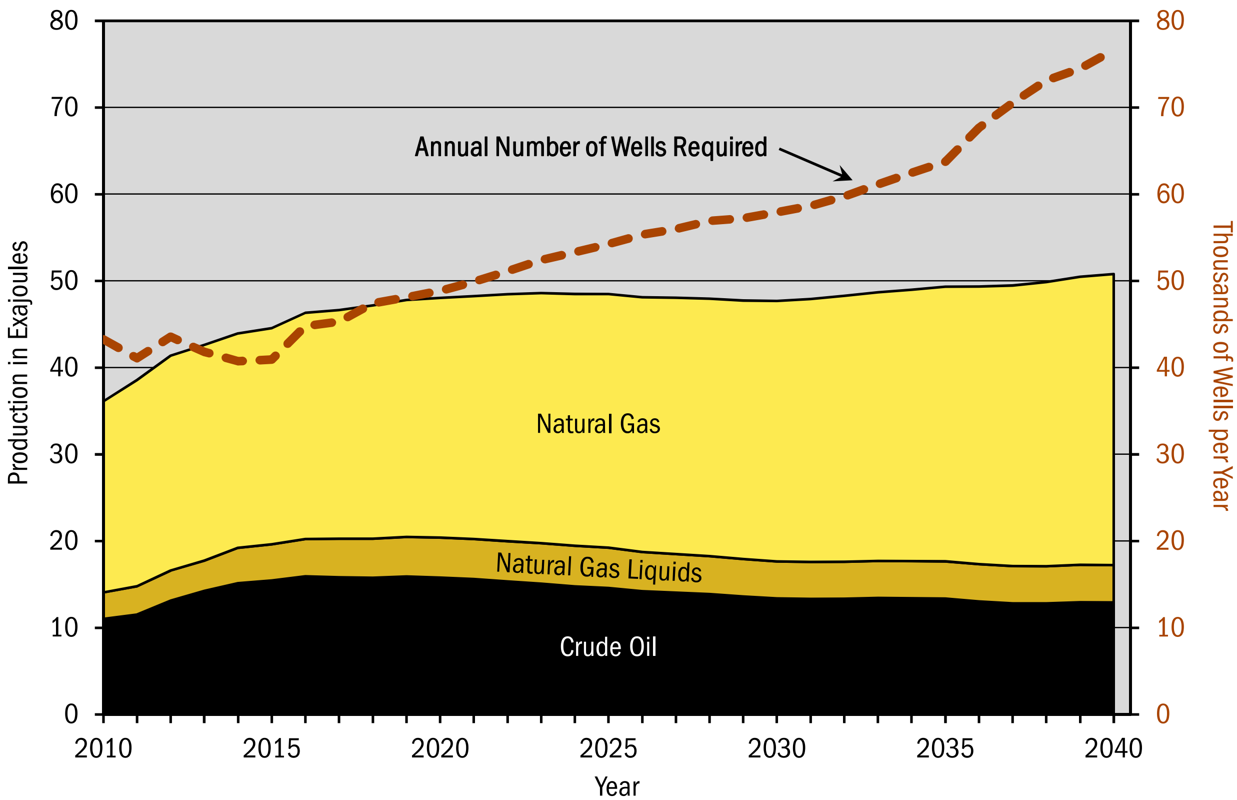

Figure 35. U.S. oil and natural gas production forecast versus drilling requirements, 2010-2040 (EIA Reference Case, 2013).[70]

Drilling must increase by 77 percent over 2010 levels by 2040 in order to grow energy production by 40 percent.

Given the realities of geology, the mature nature of the exploration and development of U.S. oil and gas resources and projected prices, it is unlikely that the EIA projections of production can be met. Nonetheless these projections are widely used as a credible assessment of future U.S. energy prospects.

[69] Data from EIA Annual Energy Outlook 2013 early release, Table 14.

[70] Natural Gas Liquids converted to crude oil equivalent energy using a 35% discount of energy content per volume unit. Data from EIA Annual Energy Outlook 2013 early release, Tables 11 and 14.

UNDERSTANDING RESERVES AND SUPPLIES

Much has been made of huge estimates of unconventional resources as a virtually limitless source of oil and gas. Diagrams such as those presented in Figure 36 have been touted by many as evidence that resource limitations are the least of our worries. They promise trillions of barrels of supply at prices less than today's price of oil. To put these estimates in perspective, current conventional reserves are listed in the BP Statistical Review of World Energy as 1,263 billion barrels[71], or about the amount of oil that has been consumed since 1858. In 2012, BP included for the first time 389 billion barrels of unconventional oil in the Canadian tar sands and the Venezuela extra-heavy oil Orinoco Belt in its main estimates, for a total of 1,652 billion barrels.

In reality, there is compelling evidence to show that even the widely-cited estimates of global oil reserves provided by BP are inflated. This includes the rapid escalation of reported reserves by OPEC countries in the late 1980's, when the basis for setting production quotas changed to reported reserves—which resulted in reported reserves suddenly increasing by more than 300 billion barrels despite there being no significant new discoveries. Saudi Arabia's reserves reported by BP, for example, have not materially changed since 1989 despite producing nearly 100 billion barrels since then. BP is careful to note in the following disclaimer that its reported estimates of remaining world oil "reserves" do not comply with the accepted definition of reserves, nor even with its own definition of reserves:

> ***Disclaimer*** *The data series for proved oil and gas reserves in BP Statistical Review of World Energy June 2012 does not necessarily meet the definitions, guidelines and practices used for determining proved reserves at company level, for instance, under UK accounting rules contained in the Statement of Recommended Practice, 'Accounting for Oil and Gas Exploration, Development, Production and Decommissioning Activities' (UK SORP) or as published by the US Securities and Exchange Commission, nor does it necessarily represent BP's view of proved reserves by country. Rather, the data series has been compiled using a combination of primary official sources and third-party data.*

The estimates of unconventional resource volumes and production costs illustrated in Figure 36 are highly speculative and as such are totally unproven. Although there is little doubt that *in situ* resources of unconventional hydrocarbons are vast, the proportion that can be recovered economically and at a net energy profit is much smaller and in some cases nonexistent. Further considerations are the rate at which these resources can be produced and the collateral environmental damage entailed in their production.

Another way of looking at oil and gas resources is illustrated by the resource pyramid of Figure 37. The highest quality resources in the most concentrated accumulations which can be recovered at the lowest cost are at the top of the pyramid. These are supergiant and giant conventional oil fields, as well as very large gas fields, which are typically discovered and developed early in the exploration cycle. Although there are approximately 70,000 active oil fields in the world, 60 percent of production comes from 374 fields and 20 percent from only 10 fields, with one field—Ghawar in Saudi Arabia—accounting for 7 percent alone.[72]

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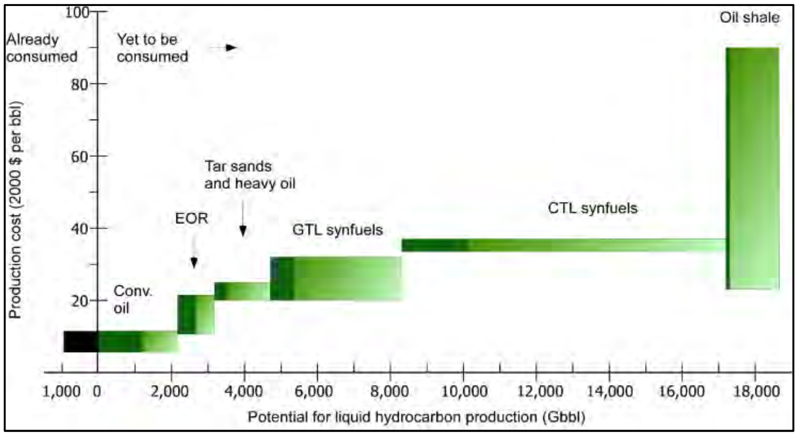
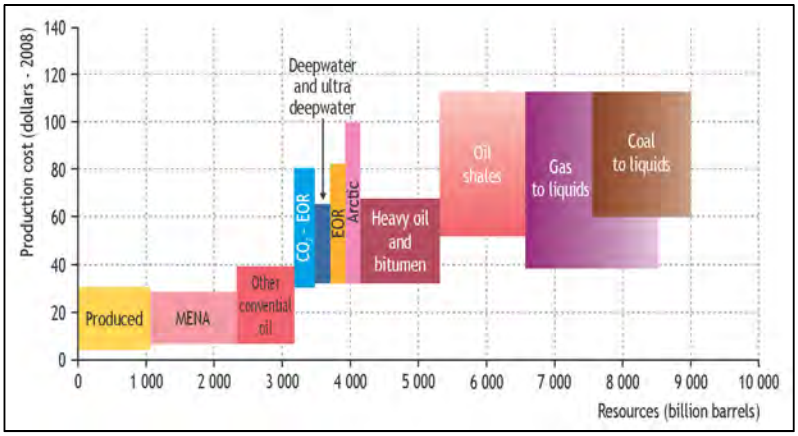
[71] BP, *Statistical Review of World Energy*, 2012.

[72] UK Energy Research Centre, "Global Oil Depletion," 2009, page 45, http://www.ukerc.ac.uk/support/tiki-download_file.php?fileId=283.

A. "Global supply of liquid hydrocarbons," (Farrell and Brandt, 2006)



B. "Long-term oil-supply cost curve," (IEA, 2008)



C. "IEA oil production cost curve," (IEA, 2011)

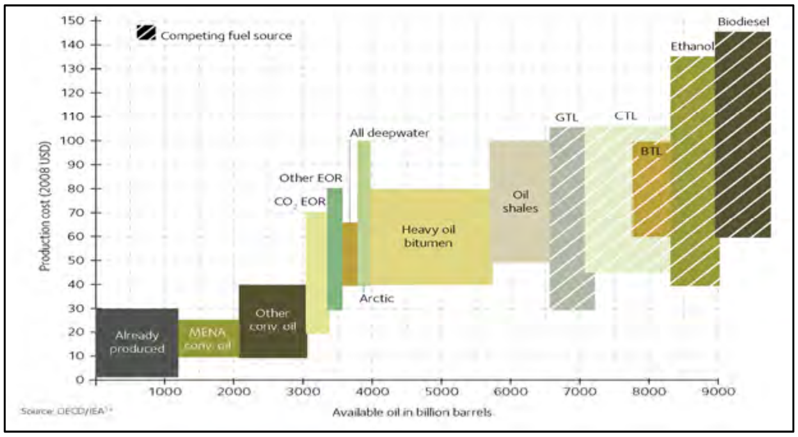


Figure 36. Three estimates of the production costs and available volume of conventional and unconventional petroleum liquid resources.

Estimates published by Farrell and Brandt, 2006; IEA, 2008; IEA, 2011.[73] The wide variance in cost estimates and volumes indicate their highly speculative nature.

[73] Top from A. Farrell and A. Brandt, "Risks of the Oil Transition," *Environ. Res. Lett.* 2006, 1 014004; Center from IEA *World Energy Outlook*, 2008; Bottom from IEA Flyer for Resources to Reserves 2010 (forthcoming publication) as reproduced in Oil Change International, *Reserves Replacement Ratio in a Marginal Oil World: Adequate Indicator or Subprime Statistic?*, January 2011.

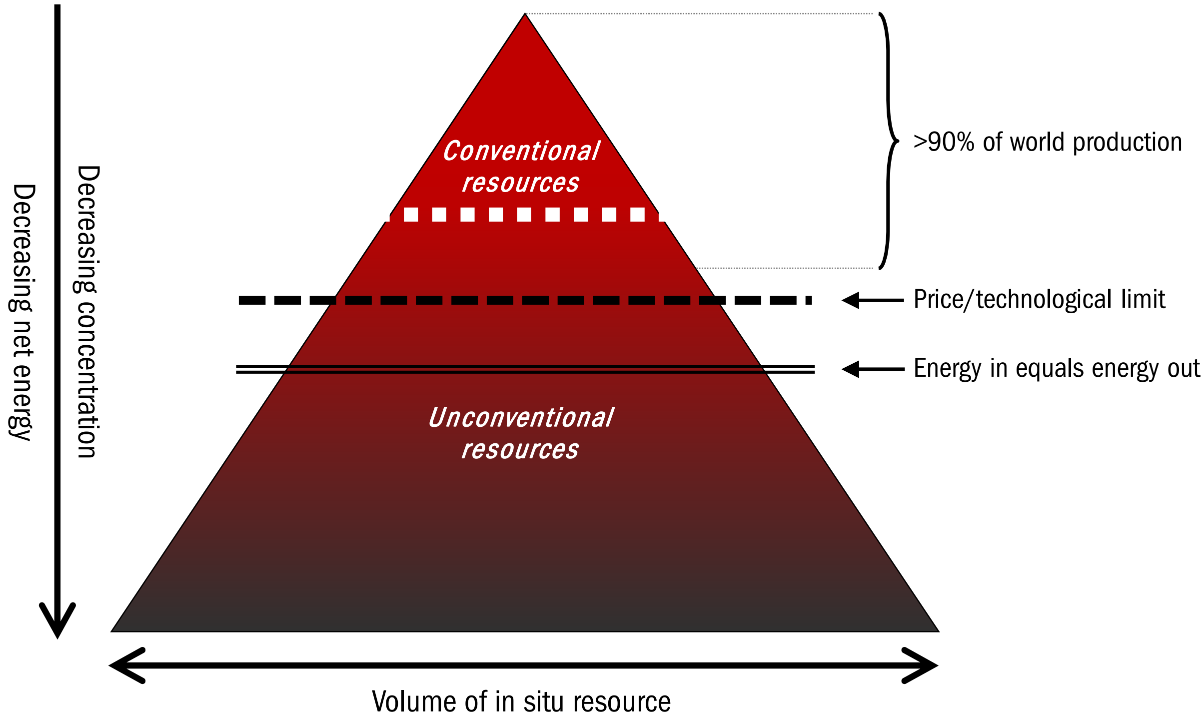


Figure 37. The pyramid of oil and gas resource volume versus resource quality.

This graphic illustrates the relationship of in situ resource volumes to the distribution of conventional and unconventional accumulations and the generally declining net energy and increasing difficulty of extraction as volumes increase lower in the pyramid.

As one moves lower in the pyramid resource volumes increase, resource quality decreases, hydrocarbons become more dispersed, and the energy required to extract them increases. A dashed line represents the transition from high quality, low cost, conventional resources and lower quality, higher cost, unconventional resources. The hydrocarbon resources at the base of the pyramid are extraordinarily plentiful, but totally inaccessible.

Two other lines on this pyramid determine the proportion of the resources that are accessible to humans. The price/technology line reflects the fact that as prices go higher, higher cost (but lower quality) resources become accessible. Also technological innovations, such as we have seen recently with the development of multi-stage hydraulic fracturing, make previously inaccessible resources available. The ultimate barrier is the second line, which is the point when the amount of energy in the resources that are recovered is less than or equal to the energy that must be invested to recover them. All resources below this line represent an energy sink, not an energy source.

Politicians and pundits often do not see the importance of these differences in resource quality which ultimately impact the *rate* at which hydrocarbons can be produced and the *net energy* they will provide to do useful work. They instead look only at purported resource volumes and trumpet *"one hundred years of natural gas"* or *"U.S. energy independence is just around the corner."* Given the importance of the concepts of *net energy* and *rate of supply* in evaluating unconventional hydrocarbon resources they are explored in more detail below.

NET ENERGY AND ENERGY RETURNED ON ENERGY INVESTED

Net energy is the energy provided to do useful work after subtracting all energy inputs in acquiring the resource. It is expressed by a ratio termed "energy returned on energy invested" (EROEI). Murphy and Hall provide a good review of the concept, as well as estimates of EROEI for various energy sources.[74]

Figure 38 illustrates the concept for various petroleum liquids sources. So, for example, acquiring a net barrel of oil from conventional sources requires burning only one twenty-fourth of a barrel in the acquisition process, whereas acquiring a net barrel of upgraded synthetic oil from in situ tar sands requires burning nearly half a barrel. Gagnon et al. estimated the EROEI of global oil and gas production at the wellhead at 18:1, (although they did not separate oil from gas).[75] Acquiring a net barrel from corn ethanol production requires burning four barrels in the acquisition process.

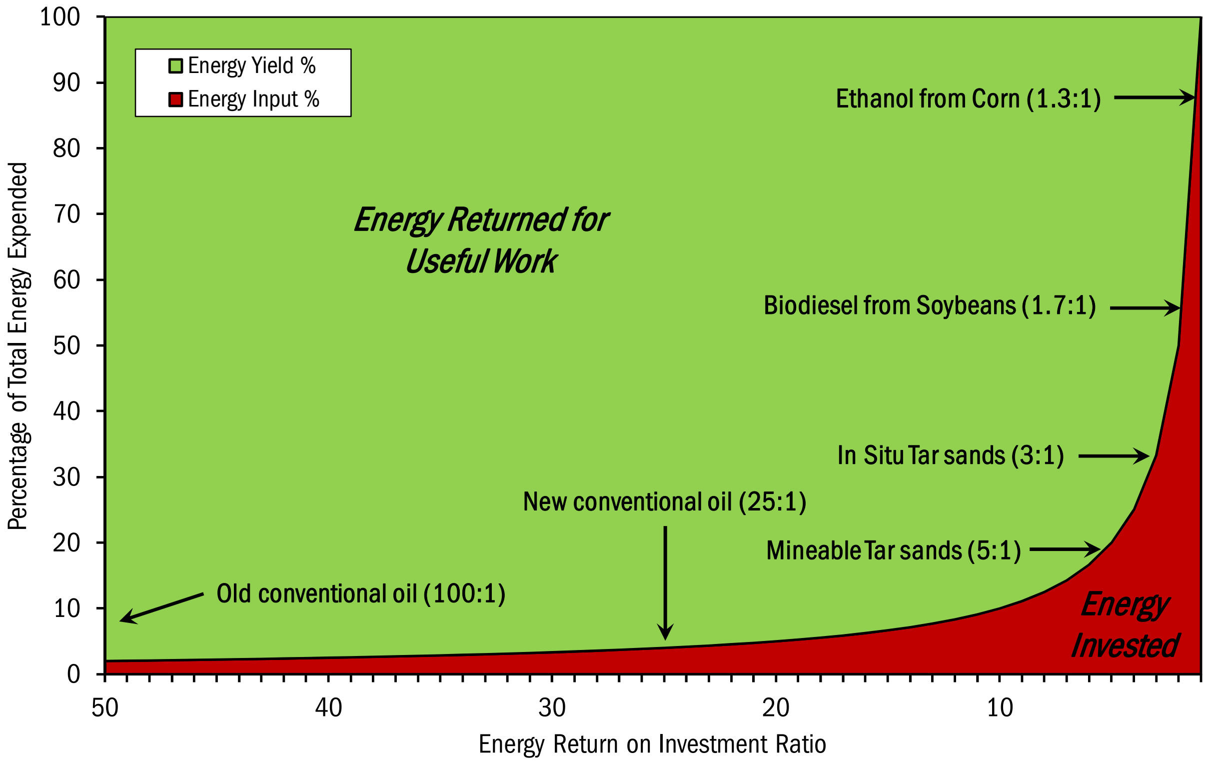


Figure 38. Energy available to do useful work as a proportion of total energy expended.

From a net energy point of view, moving to progressively lower-quality energy resources diverts more and more resources to the act of acquisition as opposed to doing useful work. This is critical for a society that requires a certain level of energy supply; all the barrels burned in producing corn ethanol, for example, serve only to deplete non-renewable hydrocarbons more rapidly while contributing minimally to useful work. The environmental impact of extracting resources also generally increases as net energy yield declines, both from the physical impact on the landscape and in terms of greenhouse gas and other emissions.

[74] David J. Murphy and Charles A.S. Hall, "Year in Review – EROI or energy return on (energy) invested", *Annals of the New York Academy of Sciences* 1185, 2010, pages 102-118, http://www.soest.hawaii.edu/GG/FACULTY/ITO/GG410/EROI_Future_Energy_Sources/Murphy_EROI_AnNYAcSci10.pdf.
[75] Nathan Gagnon et al., "A preliminary Investigation of Energy Return on Energy Investment for Global Oil and Gas Production", *Energies* 2009, 2(3), 490-503; doi:10.3390/en20300490, http://www.mdpi.com/1996-1073/2/3/490.

Although the net energy returned is critical in evaluating the energy options available for the future, the precise calculation of EROEI is subject to differences of opinion. Charles Hall and Douglas Hansen offer an excellent compendium of papers on various aspects of EROEI analysis,[76] including a paper by Hall et al. which dissects differences in the calculation of EROEI for various biofuels.[77].

RATE OF SUPPLY AND SCALABILITY

Perhaps the most crucial parameter for evaluating the viability of future energy resources is the rate at which they can be converted to useful energy supplies. This parameter is mostly ignored by the proponents of various alternative energy schemes and politicians seeking to paint rosy energy futures.

For example, although the oil shale resources in Colorado, Utah, and Wyoming are vast, purported to exceed all the remaining conventional oil resources in the world, no one has succeeded in converting them to useful supply at commercial rates despite many decades of trying. Tight oil resources, heralded by some as the answer to United States energy independence, require dense clusters of rapidly depleting wells and continuous new investment to maintain production, unlike the large conventional fields of yesteryear which had high flow rates and more modest well-decline rates. Similarly, although the sunlight that falls on the United States could in theory supply all its energy needs, the conversion of sunlight to electricity using solar panels remains at less than half a percent of electricity generation, and much less of total energy consumption, despite a many-fold ramp up in recent years.

Generally the lower the quality of a resource in terms of net energy yield and the amount of infrastructure and capital that must be applied to recover it, the lower its usefulness in providing energy to society. This can be simply portrayed with the concept of a “tank” and a “tap”. The “tank” refers to the ultimate size of the resource whereas the “tap” refers to the rate at which the resource can be converted into useful energy supply for society.

As illustrated in the first part of this report, the global and United States energy taps are open very widely, whereas the tank of traditional conventional fuels is depleting rapidly. In the case of oil, for example, the world is now consuming 32 billion barrels per year. Notwithstanding the issues with world conventional resource estimates discussed earlier, the tank will last just 39 years at current consumption rates if these estimates are correct, and a further 12 years if unconventional resources from Canadian tar sands and Venezuela extra-heavy oil are included. The lifespan of this oil tank will be much less, however, if the tap is opened yet further as forecasts of consumption growth suggest it will.

The question is, to what extent will new discoveries of conventional resources and the development of unconventional resources allow the tap to remain open at current and forecast rates of energy consumption? Pundits and politicians who wax on about “100 years of natural gas” are probably right that there is one hundred years’ worth of recoverable oil and gas at current production rates—it’s just that it may take 800 or more years to recover it. In other words, as our reliance on unconventional oil and gas grows, production rates are increasingly difficult to maintain because tomorrow’s resources are so much more technically challenging to produce than today’s. Falling rates of supply are a much more critical problem in the current economic growth paradigm than “running out”, which is unlikely to ever happen.

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[76] Charles A.S. Hall and Doug Hansen, “New Studies in EROI (Energy Return on Investment”, *Sustainability* 2011, 3(12), 2496-2499; doi:10.3390/su3122496.

[77] Charles A.S. Hall, Bruce E. Dale and David Pimentel, 2011, “Seeking to Understand the Reasons for Different Energy Return on Investment (EROI) Estimates for Biofuels”, *Sustainability* 2011, 3, 2413-2432; doi:10.3390/su3122413.

UNCONVENTIONAL FUELS AND THEIR POTENTIAL

This section reviews the potential and constraints of widely celebrated unconventional fossil fuels as a source of "energy independence" and "limitless growth." It begins with a detailed analysis of shale gas and tight oil (shale oil), which are at the top of the list in the new enthusiasm of "energy independence" for the United States. It then reviews other unconventional sources of oil and gas.

THE SHALE "REVOLUTION"

The advent of new technology involving horizontal drilling coupled with multi-stage hydraulic-fracturing has released a flood of new gas production onto the United States market. This technology has also been successfully applied to tight oil (also known as "shale" oil), resulting in a reversal of the long standing decline in domestic United States crude oil production. It marks a watershed in the production of oil and gas. Formerly production was from reservoirs filled with hydrocarbons that had migrated from shale source rocks over millions of years. Now production is from the source rocks themselves.

In order to understand what is really happening with these shale plays, drilling and production data from across the United States were analyzed in depth. Figure 39 illustrates some of the plays that were examined.

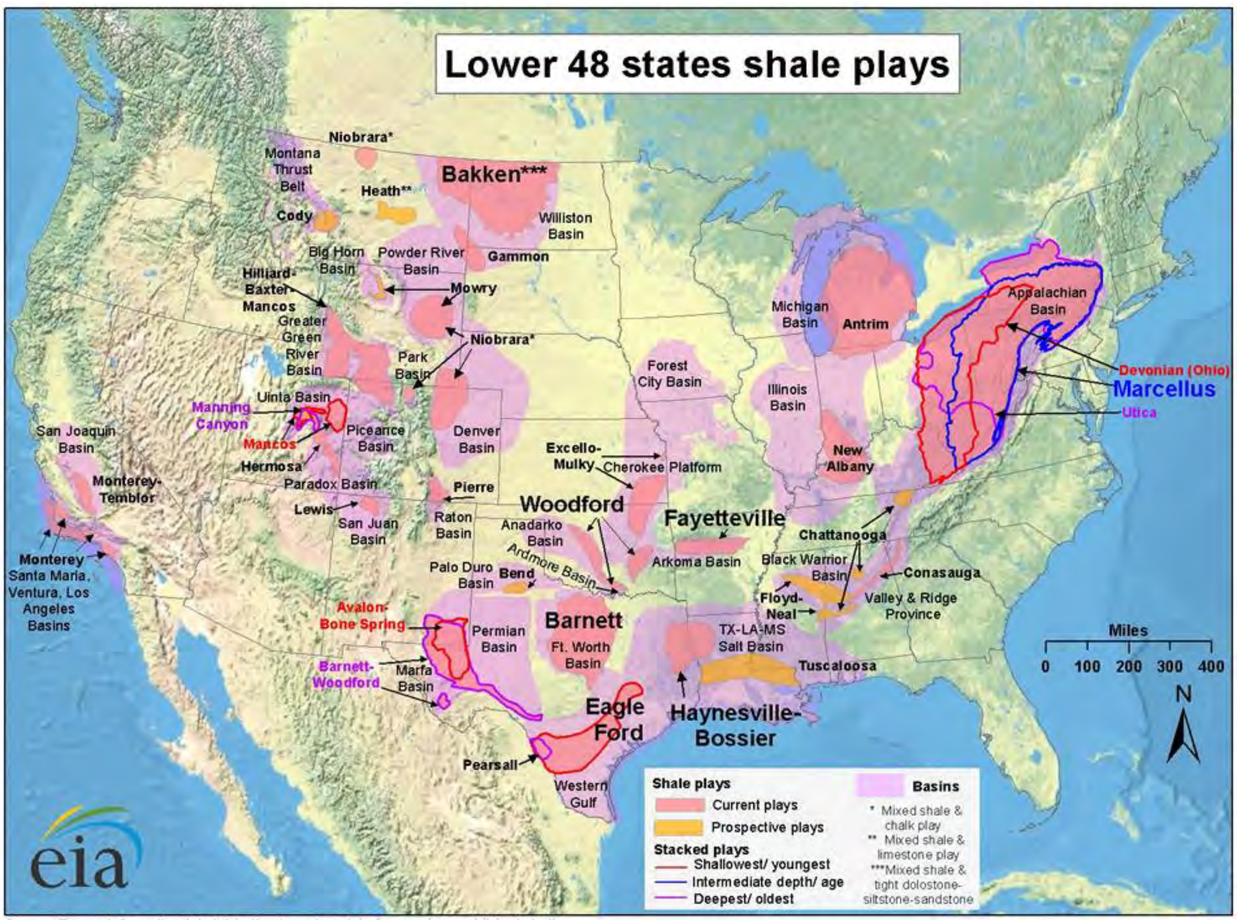

Figure 39. Shale plays of the Lower 48 United States.[78]

[78] Data from EIA updated to September, 2011, http://www.eia.gov/oil_gas/rpd/shale_gas.jpg.

The map in Figure 39 suggests that shale plays are found in many regions of the United States. Industry at one time declared that shale plays were "manufacturing" operations, where wells could be drilled with uniform production across broad stretches of geography without regard to local variations in reservoir parameters. In fact, it has since been found that shale plays are highly variable, with a few highly productive plays, and sweet spots within plays, and much larger regions with marginal or uneconomic production. Even wells drilled from the same pad may have widely varying production characteristics.

Commercial production from shale plays is possible only due to the advent of large-scale multi-stage hydraulic fracturing of horizontal wells. Although production is predominantly from shale, it is also obtained from associated tight carbonates and siltstones in some tight oil plays. Fractures must be induced in the reservoir owing to its very low permeability (in the micro- or nano-darcy range). Natural fracture systems which can be connected through the hydraulic fracturing process aid in production, and the "brittleness" of the rock, which is a function of silica content, determines the effectiveness of propagating fractures. Fractures are held open by proppant – a mix of sand and other additives – so that gas and oil can migrate to well bores. The highly impermeable nature of shale and other tight oil rocks is responsible for the rapid declines in production, given the limited amount of rock that can be drained adjacent to induced and natural fractures.

Shale Gas

KEY TAKEAWAYS

- Shale gas has grown very rapidly to account for nearly 40 percent of U.S. natural gas production, although production has plateaued since early 2012. This has more than made up for declines in conventional gas production and has allowed an increase in overall gas production to record levels.
- The drilling boom which resulted in this glut of shale gas was in part motivated by "held-by-production" arrangements in three to five year lease agreements, by requirements of joint venture arrangements and by the need to book reserves to support share valuation on the stock market.
- High productivity shale plays are not ubiquitous, and relatively small sweet spots within plays offer the most potential. Six of thirty shale plays provide 88 percent of production.
- Individual well decline rates are high, ranging from 79 to 95 percent after 36 months. Although some wells can be extremely productive, they are typically a small percentage of the total and are concentrated in sweet spots.
- Overall field declines require from 30 to 50 percent of production to be replaced annually with more drilling. This translates to $42 billion of annual capital investment to maintain current production. By comparison, shale gas produced in 2012 was worth about $32.5 billion at a gas price of $3.40/mcf (which is higher than actual well head prices for most of 2012).
- Capital inputs to offset field decline will increase going forward as the sweet spots within plays are drilled off and drilling moves to lower quality areas. Average well quality (as measured by initial productivity) has fallen nearly 20 percent in the Haynesville, which is the most productive shale gas play in the U.S., and is falling or flat in eight of the top ten plays. Overall well quality is declining for 36 percent of U.S. shale gas production and is flat for 34 percent.
- Dry shale gas plays are not economic at current gas prices, hence drilling has shifted to tight oil and wet gas plays which have better economics. Once the inventory of drilled-but-not-yet-on-production wells is worked off, shale gas production will decline. This will facilitate considerably higher gas prices going forward. The idea that gas prices will remain below $5/mcf until 2026, as projected by the EIA (Figure 34), is wishful thinking.
- The EIA recently revised its estimate of unproved technically recoverable shale gas resources downward by 42 percent to 482 trillion cubic feet (tcf). Coupled with shale gas reserves this yields a total of 579 tcf, or 24 years of supply at current production rates. The EIA projects that 382 tcf, or 66 percent of this will be consumed by 2040 (Figure 32). This is an extremely aggressive forecast, considering that most of this production is from unproved resources, and would entail a drilling boom that would make the environmental concerns with hydraulic-fracturing experienced to date pale by comparison.

Shale gas production has grown from about two percent of United States production in 2000 to nearly forty percent today. The majority of wells drilled are now horizontal, usually deploying multi-stage hydraulic fracturing. Notwithstanding the assertions of industry that this technology is benign, the public pushback against the practice is very extensive. As illustrated in Figure 40, shale gas production appears to be plateauing as of late 2011.

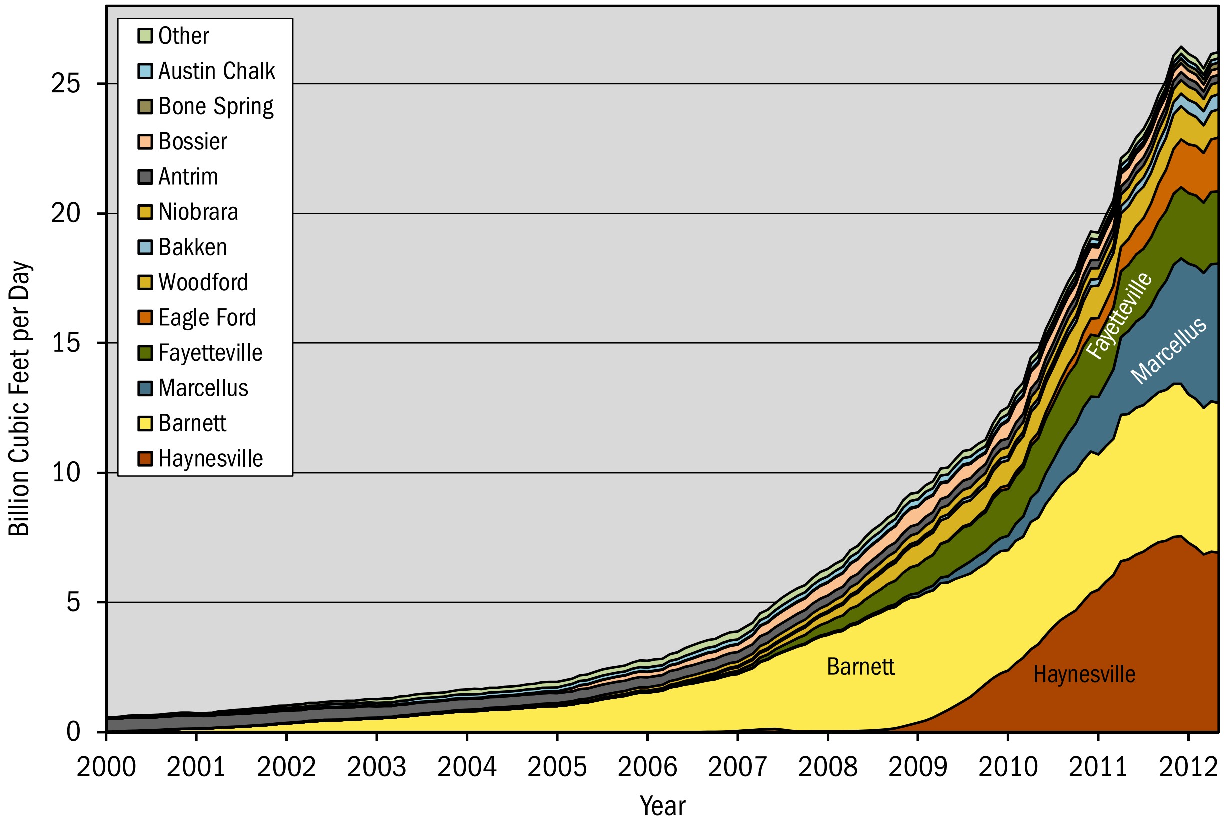

Figure 40. Shale gas production by play, 2000 through May 2012[79].

Shale gas now constitutes nearly forty percent of United States production.

Shale gas production began in a big way in the Barnett play of eastern Texas in the early part of the last decade. As of May 2012, 14,871 wells were producing 5.85 billion cubic feet of gas per day, making the Barnett the second largest shale gas field in the United States. It was here that the technology of multi-stage hydraulic-fracturing of shale was developed and refined. The Haynesville play of eastern Texas and western Louisiana went from nothing in 2007 to become the number-one producer in the United States. Similarly, the Marcellus play of Pennsylvania and West Virginia went from nothing to become the third largest producer over a similar timeframe. Together, these three plays constitute two-thirds of United States shale gas production.

[79] Data from DI Desktop/HPDI current through May, 2012, fitted with three month moving average.

Figure 41 illustrates the production of 30 shale plays as of May 2012. As can be seen, the majority of production is concentrated in the top three plays with the top six constituting 88 percent of production. The bottom seventeen plays collectively contribute just over one percent of production.

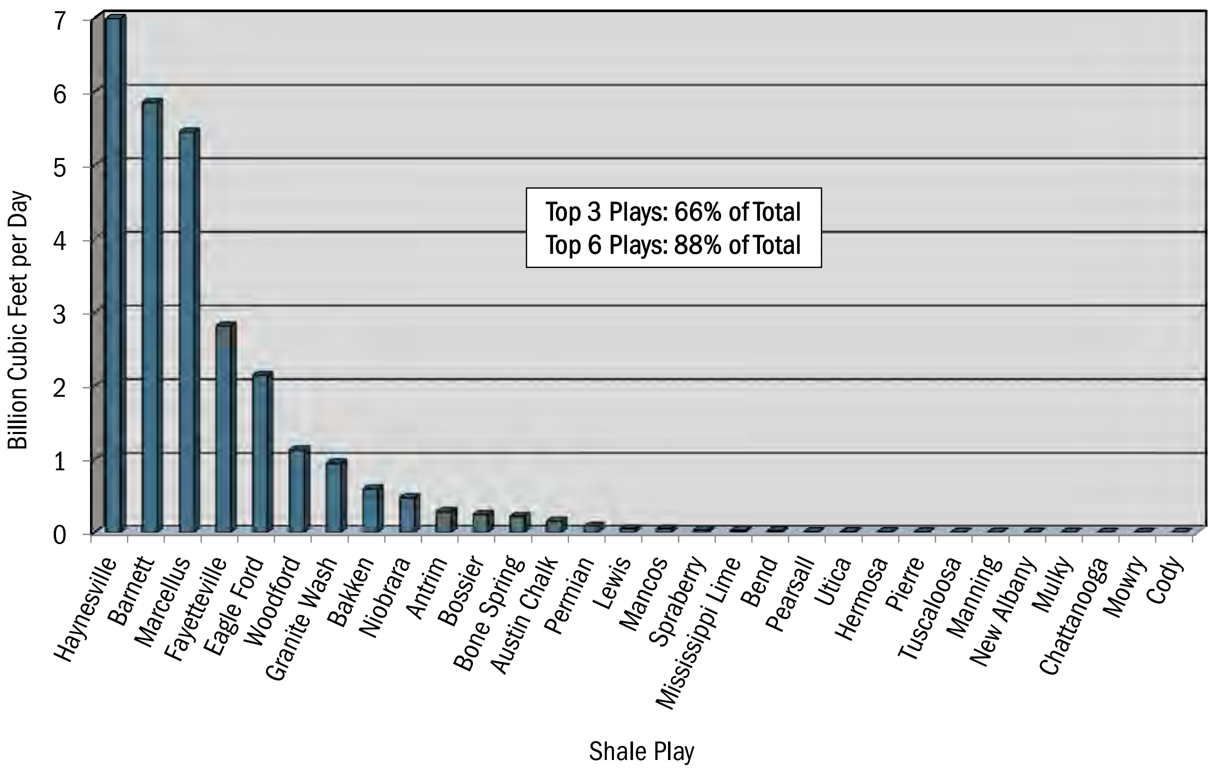

Figure 41. Shale gas production by play, May 2012.[80]

Note that the Granite Wash is technically tight sand, not shale, but is included for information.

Figure 41 illustrates that shale gas plays with high productivity characteristics are not ubiquitous, and that the best of them are relative rarities. All shale plays are not created equal, and there is considerable variation in productivity even within the best plays. Furthermore, due to their high decline rates, these plays require high levels of capital input for drilling and infrastructure development to maintain current production levels. In order to illustrate these points, a more detailed analysis of the top three shale gas plays is offered below.

[80] Data from DI Desktop/HPDI current through May-June, 2012.

Haynesville Shale Gas Play

The Haynesville Shale is unique among shale plays in terms of its high individual well productivity and overall production, making it the most productive shale gas field in the United States as of May 2012. Figure 42 illustrates the growth in both production and the number of producing wells since 2008. Production appears to have peaked in December 2011, however, despite the continued growth in the number of producing wells.

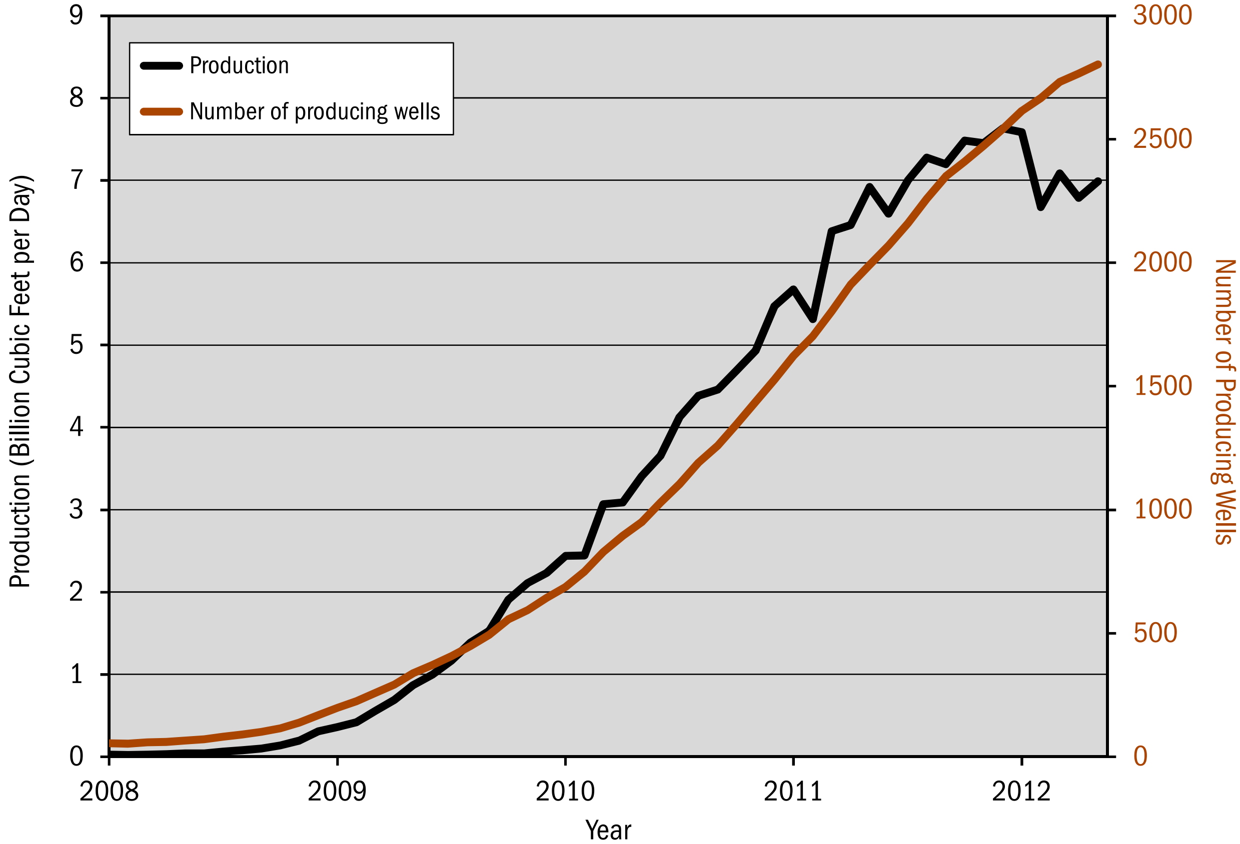

Figure 42. Shale gas production and number of producing wells for the Hayesville play, 2008 through May 2012.[81]

Production peaked in December 2012, despite continued growth in the number of operating wells.

[81] Data from DI Desktop/HPDI current through May, 2012.

Haynesville wells exhibit steep production declines over time. Figure 43 illustrates a "type" well decline curve" (an average of all wells in a play) compiled from the four years of data available since the field has been in production. The first-year decline of 68 percent is comparable with other shale plays, however the second and subsequent years' declines are atypically high. This suggests the Haynesville may not have the 30- to 40-year well-lifetime implied by the typical hyperbolic decline curves fit to such data that industry uses to determine estimated ultimate recovery (EUR). The long-term performance of Haynesville wells is uncertain at this point owing to its short production history. The mean EUR estimated recently for the Haynesville by the United States Geological Survey (USGS) is 2.617 billion cubic feet (bcf)[82], which is broadly comparable to a detailed study by Kaiser and Yu from Louisiana State University.[83] This is far lower than the typical EURs reported by industry which are generally in the 5-10 bcf range. The economics of the Haynesville are thus highly questionable at current natural gas prices ($3.30/mcf) which is reflected in a rig count that dropped from a high of 180 in mid-2010 to only 20 in October 2012.

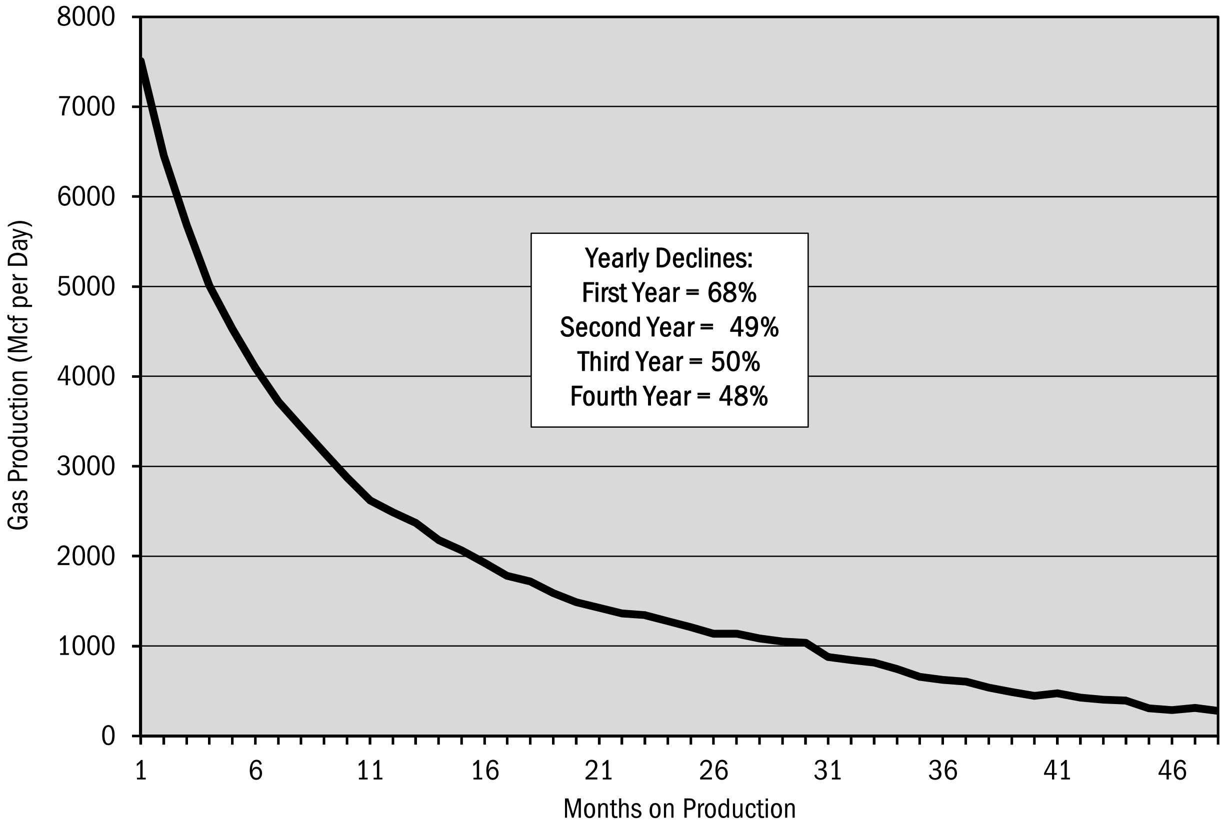

Figure 43. Type decline curve for Haynesville shale gas wells.[84]
Based on data from the four years this shale play has been in production.

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82 United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.
83 Mark J. Kaiser and Yunke Yu, "LOUISIANA HAYNESVILLE SHALE—1: Characteristics, production potential of Haynesville shale wells described," Oil and Gas Journal, December 5, 2011.
84 Data from DI Desktop/HPDI current through May, 2012.

Kaiser and Yu go on to state, "The majority of Haynesville wells fail to break even on a full-cycle basis at prevailing gas prices [<$4.00/mcf]. This harsh economic reality will control future activity after new entrants fulfill their drilling requirements."[85]

The initial productivity (IP) of a well when it is first drilled is one measure of well quality and typically bears some correlation to EUR. Figure 44 illustrates the highest one-month production recorded for wells in the Haynesville play. The distribution of IPs observed in Figure 44 is typical of shale plays, with a few very high quality wells (in this case two percent with IPs of over 20 million cubic feet per day) and the majority with much lower IPs (in this case averaging 8.2 million cubic feet per day). The highest-quality wells often receive a disproportionate amount of media coverage, however, giving a false impression of the overall characteristics of a play. Average well production in the Haynesville is much less than mean IP, at 2.5 million cubic feet per day, because of the effect of steep well declines and the fact that overall field production is from a mix of old and new wells.

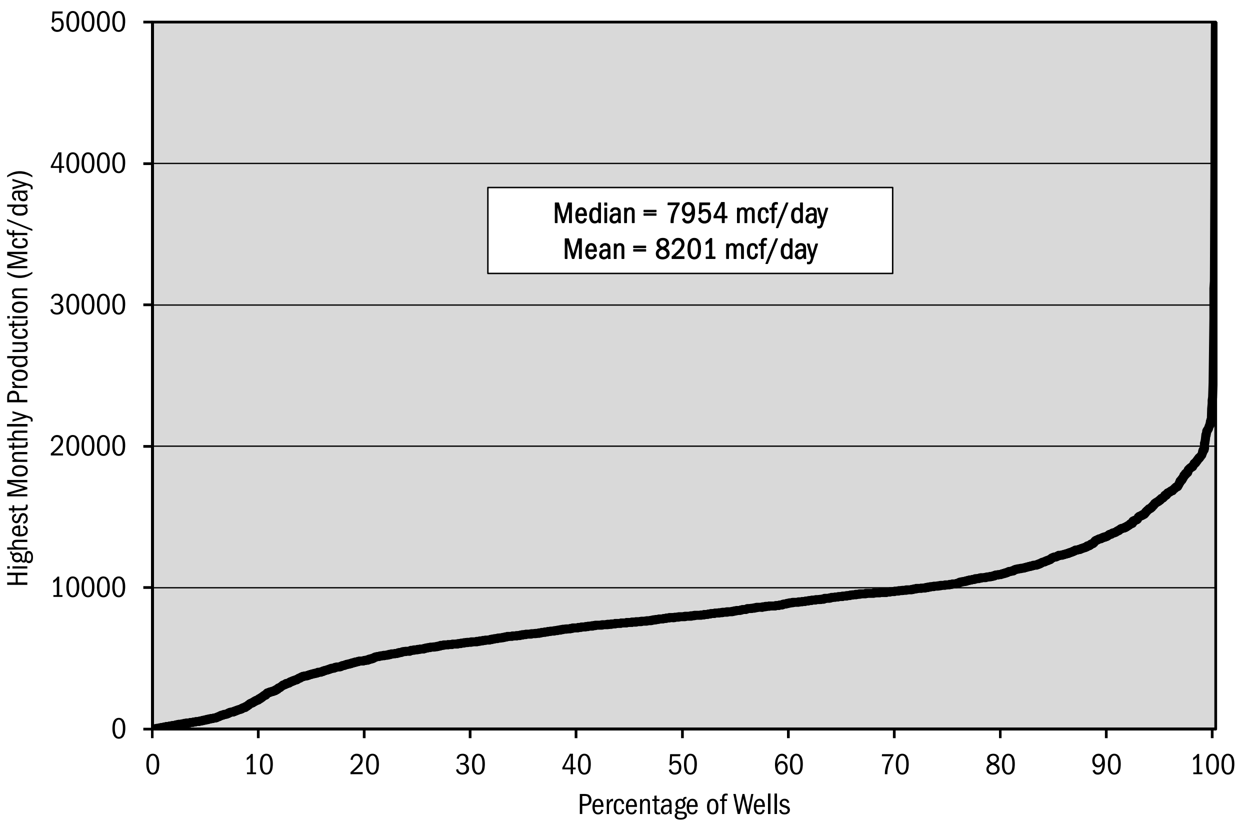

Figure 44. Distribution of well quality in the Haynesville play, as defined by the highest one-month rate of production over well life.[86]

The highest one-month rate of production is typically achieved in the first or second month after well completion.

[85] Mark J. Kaiser and Yunke Yu, 2012, "LOUISIANA HAYNESVILLE SHALE—2: Economic operating envelopes characterized for Haynesville shale," Oil and Gas Journal, January 9, 2012.

[86] Data from DI Desktop/HPDI current through May, 2012.

The overall decline rate of the Haynesville play can be estimated from the production from all wells drilled prior to 2011, as illustrated in Figure 45. The yearly overall field decline rate for those wells is about 52 percent. Assuming new wells will produce for their first year at the first-year rates observed for wells drilled in 2011, 774 new wells would be required to offset field decline each year from current production levels. At an average cost of $9 million per well, this would represent a capital input of about $7 billion per year, exclusive of leasing and other infrastructure costs, just to keep production flat at today's level. The current rig count in the Haynesville is sufficient to offset less than a third of the overall field decline. There are still a lot of drilled wells being completed in the Haynesville: 810 new producing wells were added in the twelve months ending May 2012, far more than the available rigs could drill. Once the current backlog of wells drilled but not yet completed is worked off, Haynesville production will fall dramatically unless drilling rates are ramped up—but much higher gas prices would be required to make that economically worthwhile.

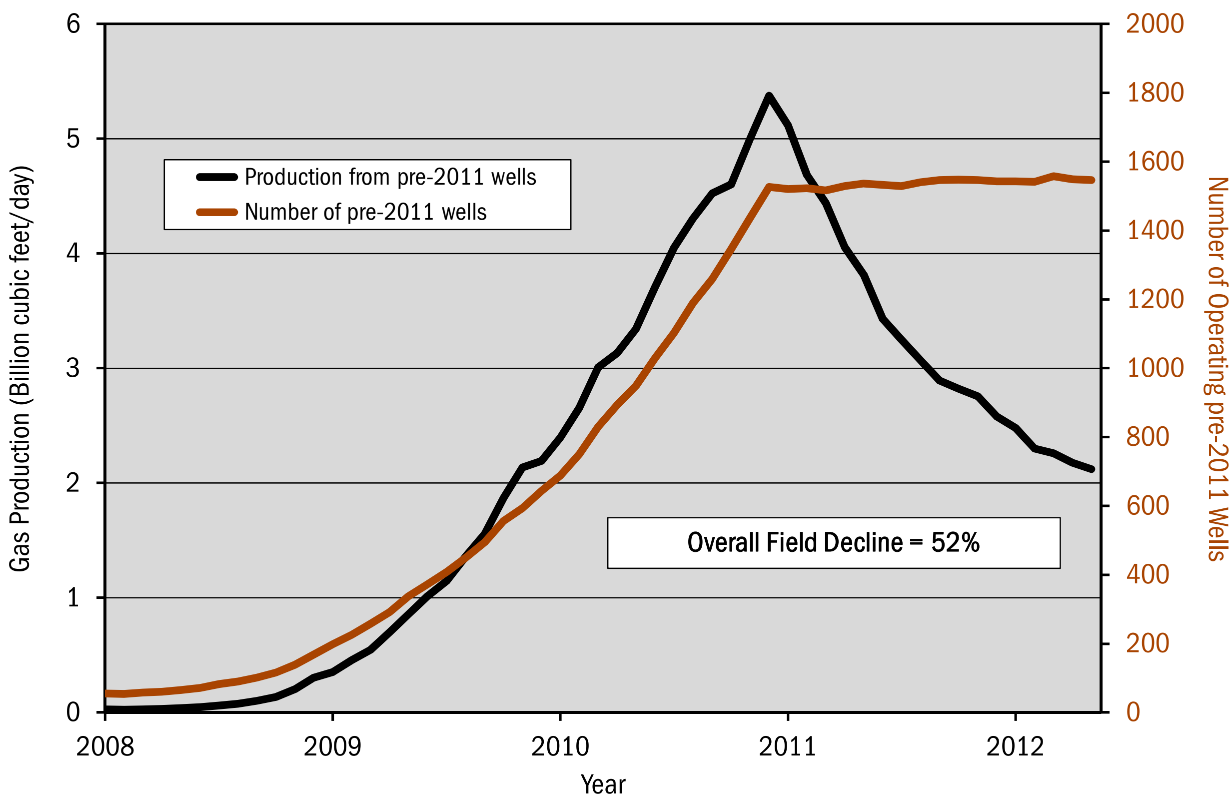

Figure 45. Overall field decline for the Haynesville play, based on production from wells drilled prior to 2011.[87]

In order to offset the 52 percent decline rate for the field, 774 new wells producing at 2011 rates are required.

[87] Data from DI Desktop/HPDI current through May, 2012.

In fact, this estimate of the number of wells required to offset overall field decline is likely optimistic, as the average initial productivity (IP) of new wells is declining. The average IP of new wells in the Haynesville peaked in 2010 at 8.3 million cubic feet per day (MMcf/d) and has declined to 6.75 MMcf/d in 2012. This trend is to be expected as a field matures. Operators target the highest-quality areas first, and then focus on lesser-quality areas once the best regions are drilled off. This means that increasing numbers of wells will be required to offset overall field decline, as new wells become less productive. As illustrated in Figure 46, the areas of highest productivity constitute only a small portion of the total field.

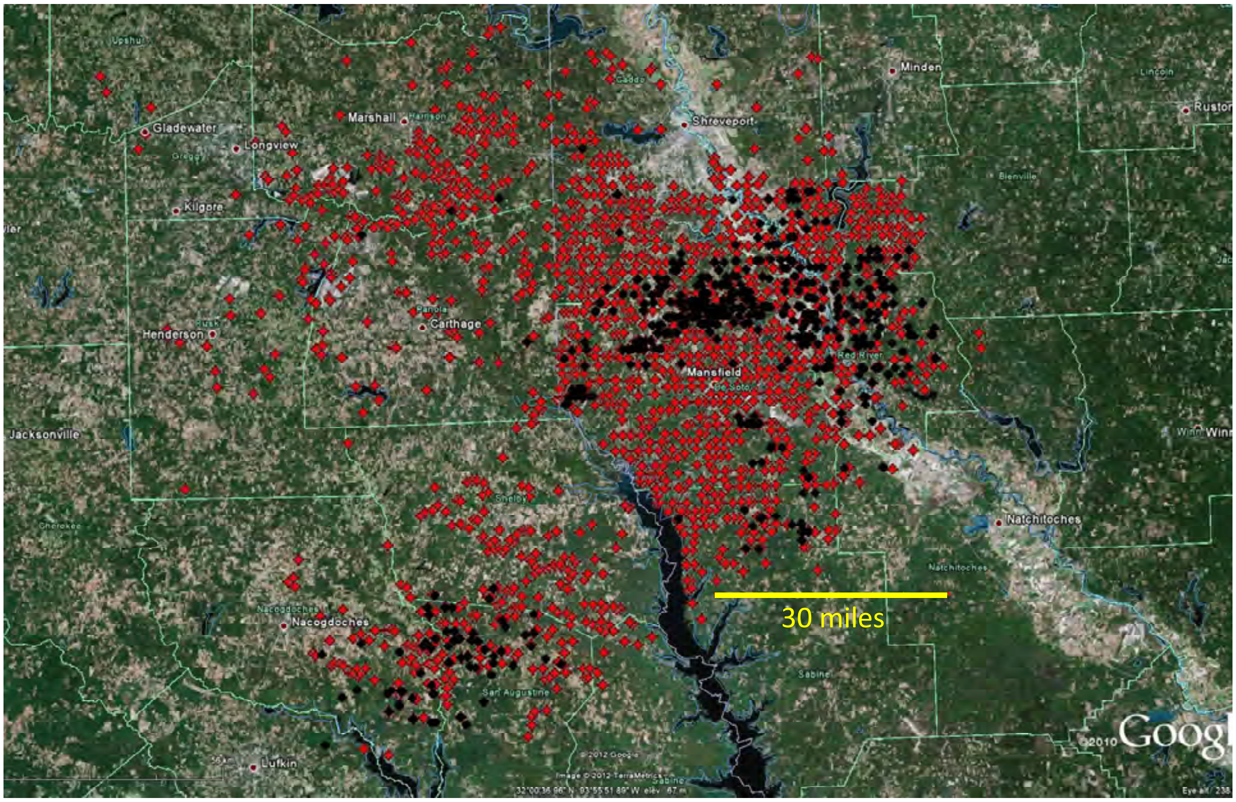

Figure 46. Distribution of wells in the Haynesville play.[88]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells. The highest-productivity wells tend to be concentrated in "sweet spots."

The final prognosis for the Haynesville play is that production will begin to fall precipitously unless gas prices rise substantially to warrant drilling enough new wells to offset field decline and grow production, as most wells are uneconomic at current gas prices. The average productivity of new wells is likely to continue to decline as high productivity core areas are drilled off and activity moves of necessity to more marginal areas. An investment of at least $7 billion per year in new wells is required to offset field decline and keep production flat. This investment requirement will increase in future years as well productivity declines.

[88] Data from DI Desktop/HPDI current through May, 2012.

Barnett Shale Gas Play

The Barnett shale play is where the application of the technology of multi-stage hydraulic fracturing of horizontal wells to liberate previously inaccessible gas from shale source rocks was first demonstrated. It is the second largest producer of shale gas in the United States with 14,871 operating wells producing 5.85 bcf/d as of May 2012. Production has plateaued beginning in December 2011 as illustrated in Figure 47, despite the continued growth in the number of operating wells.

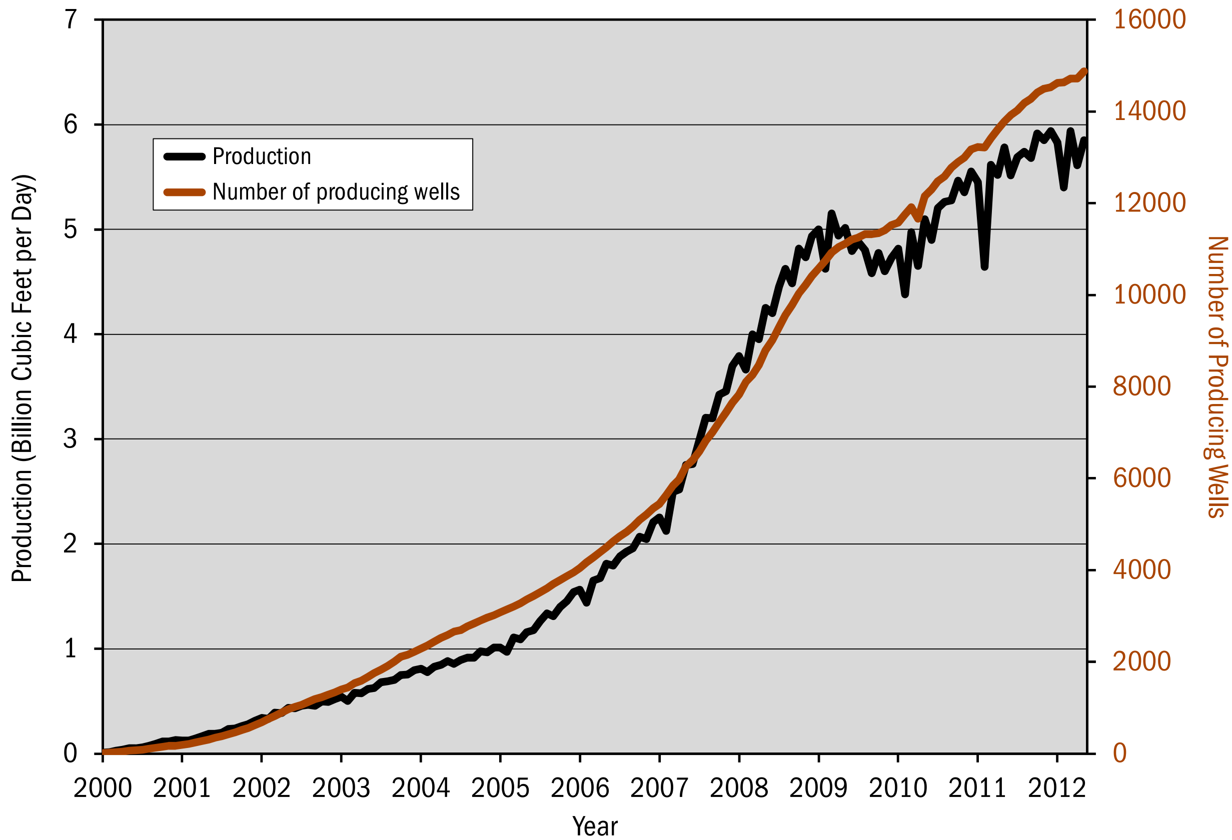

Figure 47. Shale gas production and number of producing wells for the Barnett shale play, 2000 through May 2012.[89]

Production plateaued in December 2012, despite continued growth in the number of operating wells.

[89] Data from DI Desktop/HPDI current through May, 2012.

A type well decline curve for the Barnett play is illustrated in Figure 48, based on the last five years of production data. Declines are lower than for the Haynesville in the first year and much lower in the second and subsequent years. Average EURs for the Barnett are 1.42 bcf according to the EIA's Intek consulting report[90], and 1.0 bcf according to the USGS.[91] This is corroborated by Berman et al. who suggest a mean EUR for the Barnett of 1.3 bcf and offer an extensive analysis and discussion of declines and profitability[92]. They suggest that gas prices of $8.75/MMbtu for full cycle costs and $5.63/MMbtu for well-only costs are required in the Barnett to break even. This means that the average Barnett well is uneconomic at current gas prices of $3.30/MMbtu. As Berman et al. point out, industry claims of EURs for the Barnett are much higher, at 2-2.65 bcf, and an EUR of 3.0 bcf is claimed by Skone et al. of the National Energy Technology Laboratory (NETL) without any backup analysis.[93] Clearly the claims by industry about the profitability of the Barnett are exaggerated when subjected to rigorous analysis; much of this stems from the short lifespan of shale wells and the uncertainty of projecting long term production.

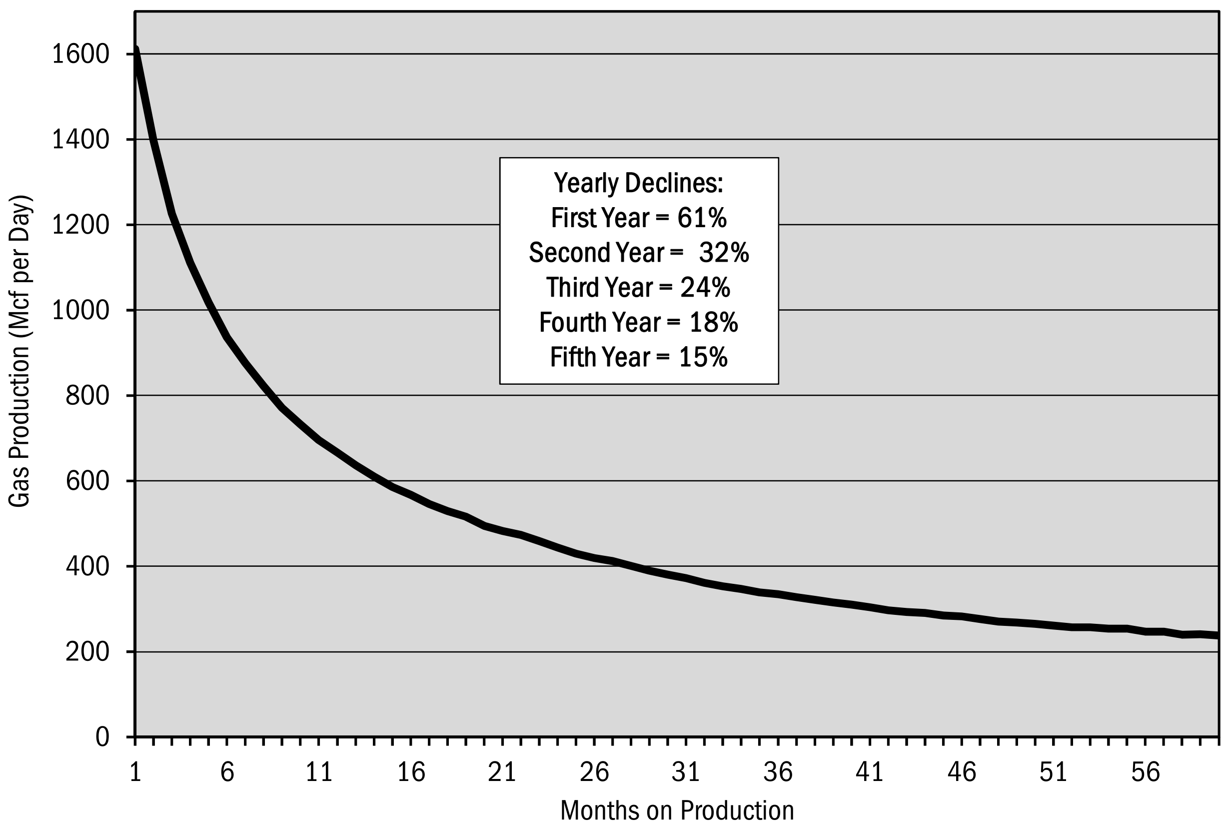

Figure 48. Type decline curve for Barnett shale gas wells.[94]
Based on data from the most recent five years of this play's production.

[90] EIA, "U.S. Shale Gas and Shale Oil Plays Review of Emerging Resources: U.S. Shale Gas and Shale Oil Plays," July 2011, http://www.eia.gov/analysis/studies/usshalegas/pdf/usshaleplays.pdf.
[91] United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.
[92] Arthur Berman and Lynn Pittinger, "U.S. Shale Gas: Less Abundance, Higher Cost," The Oil Drum, August 5, 2011, http://www.theoildrum.com/node/8212.
[93] Skone et al., "Role of Alternative Energy Sources: Natural Gas Power Technology Assessment," National Energy Technology Laboratory, June 30, 2012, page 25, http://www.netl.doe.gov/energy-analyses/pubs/NGTechAssess.pdf.
[94] Data from DI Desktop/HPDI current through May, 2012.

As with the Haynesville, there is a wide variation of well quality in the Barnett play as indicated by initial well productivity (IP) illustrated in Figure 49. Overall productivity is much lower than the Haynesville but is still very respectable. The best wells, with IPs of over 4 MMcf/d, and which may be economic at current gas prices, constitute only five percent of the total. The average production of a Barnett well as of June 2012, is 381mcf/d and declining.

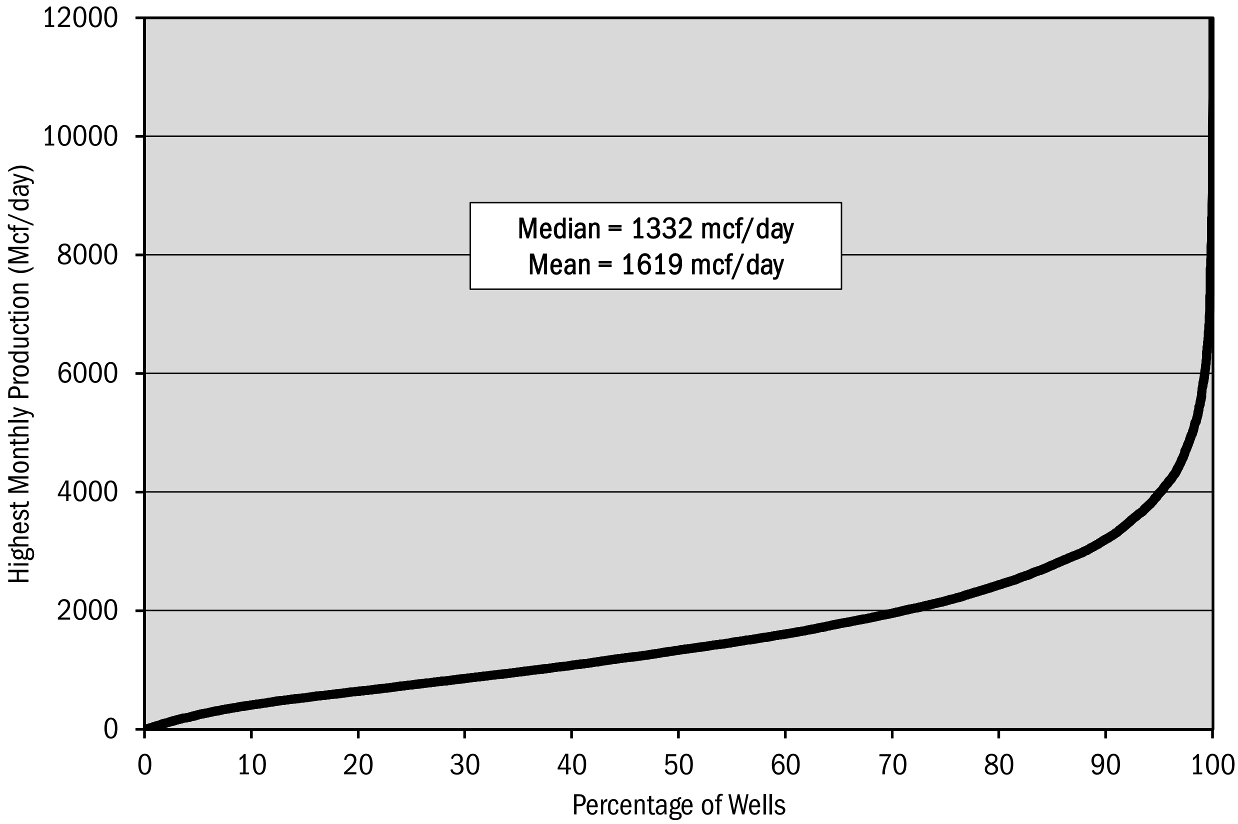

Figure 49. Distribution of well quality in the Barnett play, as defined by the highest one-month rate of production over well life.[95]

The highest one-month rate of production is typically achieved in the first or second month after well completion.

95 Data from DI Desktop/HPDI current through May, 2012.

The overall decline rate of the Barnett play can be estimated from the production from all wells drilled prior to 2011 as illustrated in Figure 50. The yearly overall field decline rate for those wells is about 30 percent. Assuming new wells will produce for their first year at the first-year rates observed for wells drilled in 2011, 1,507 new wells would be required to offset field decline from current production levels each year. At an average cost of $3.5 million per well, would represent a capital input of about $5.3 billion per year, exclusive of leasing and other infrastructure costs, to keep production flat at today's level. The rig count in the Barnett as of this writing (October 2012) is just 42, which is down 80 percent from the peak of 200 in September, 2008. Assuming each rig can drill twelve wells per year this is far below the number required to maintain current production levels in the face of overall field declines.

There are still a lot of drilled wells being completed in the Barnett, as 1,083 new producing wells were added in the twelve months ending in May 2012, far more than the available rigs could drill. Once the current backlog of wells drilled but not yet completed is worked off, Barnett production can be expected to fall unless drilling rates are ramped up dramatically.

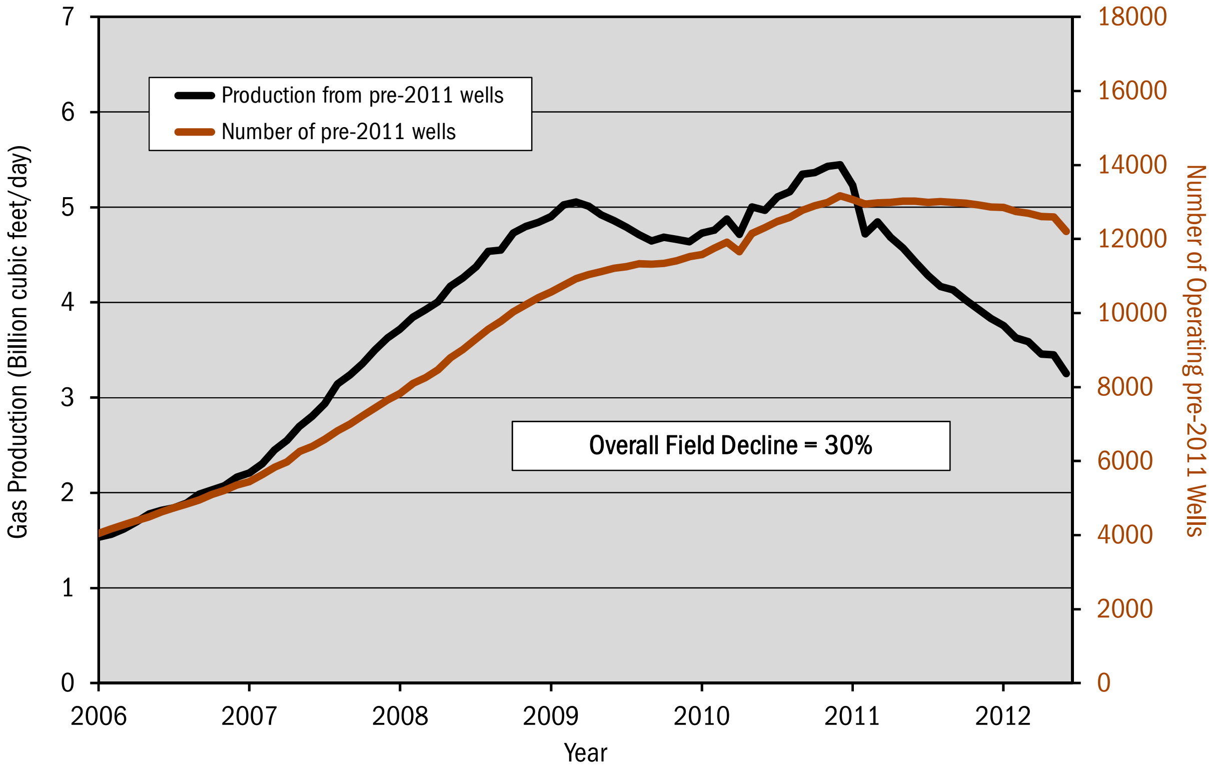

Figure 50. Overall field decline for the Barnett play based on production from wells drilled prior to 2011.[96]

In order to offset the 30 percent decline rate for the field, 1,507 new wells producing at 2011 rates are required.

[96] Data from DI Desktop/HPDI current through May, 2012.

Figure 51 illustrates the distribution of drilling in the Barnett including the core area defined by the highest well quality. Some of the highest-quality locations lie in the suburbs and urban areas on the western edge of Dallas-Fort Worth. The IPs of new Barnett wells are relatively flat, suggesting that the application of newer technology is not growing production but that there are still opportunities in the best areas, unlike in the Haynesville where IPs are falling as operators move into lower quality regions. IPs are likely to begin falling in the future as the core areas become saturated.

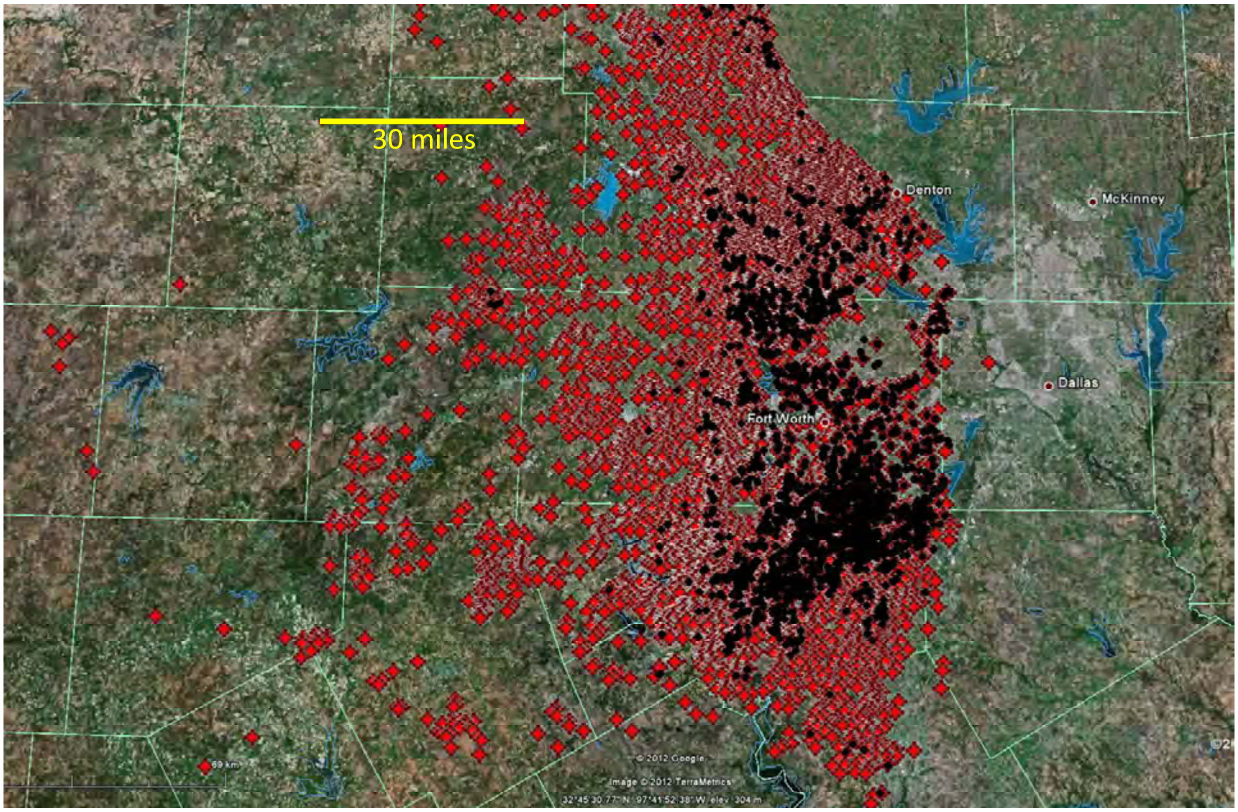

Figure 51. Distribution of wells in the Barnett play.[97]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells. The highest-productivity wells tend to be concentrated in "sweet spots."

[97] Data from DI Desktop/HPDI current through May, 2012.

The footprint of this drilling on the landscape is illustrated in Figure 52. There has been a great deal of pushback by local communities on the impact of drilling and hydraulic fracturing on both air and water. At its peak in 2008-2009 up to 2,800 wells were being added yearly. The most recent rate in the twelve months ending May 2012 was 1,083, and current activity suggests it is now about 500 new wells per year. Drilling rates must reach 1,507 new wells yearly to sustain production. The question eventually becomes: How many new wells can be squeezed in and what are the social implications of doing so?

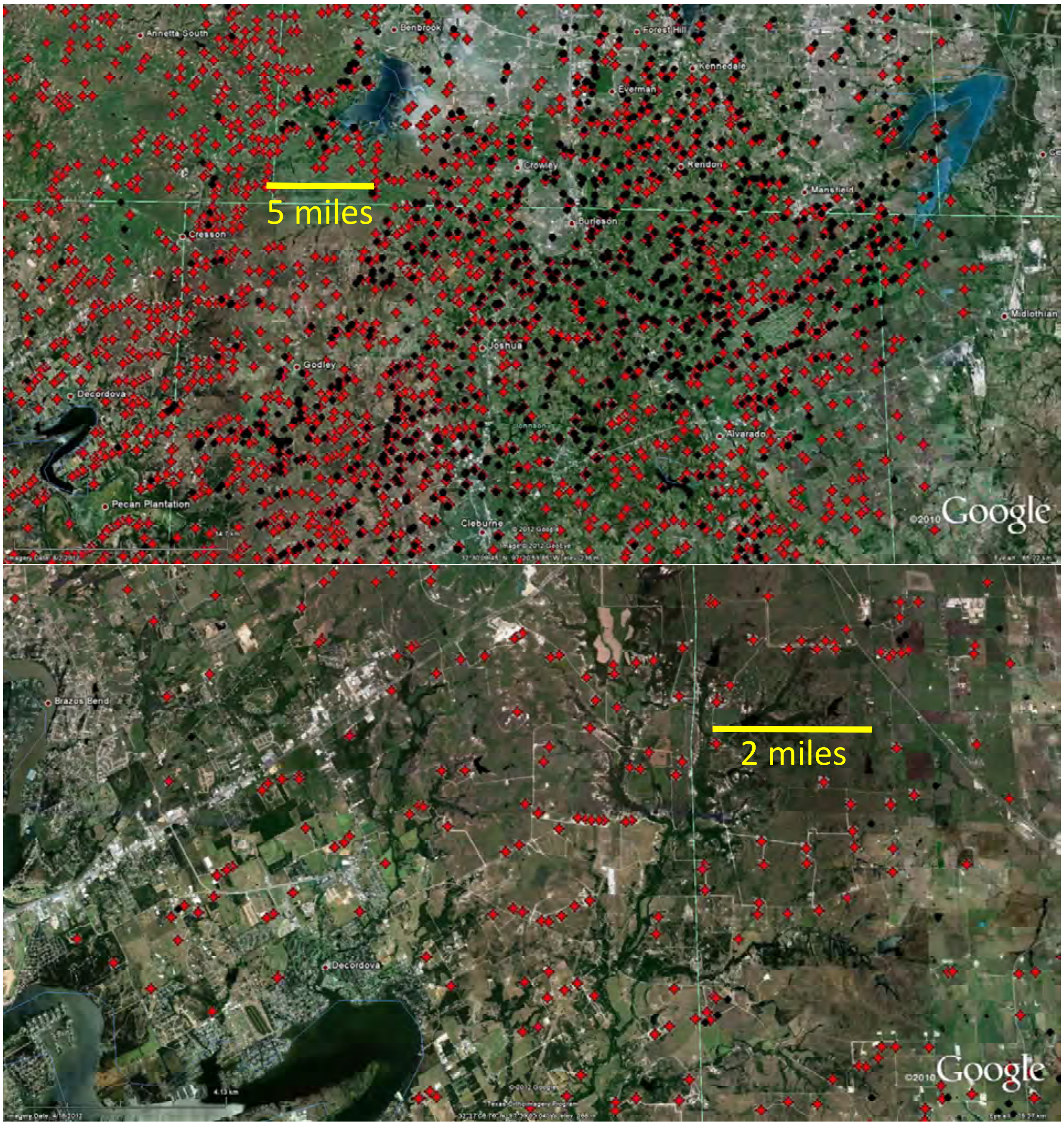

Figure 52. Distribution of wells in the Barnett play's area of highest concentration.[98]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells.

[98] Data from DI Desktop/HPDI current through May, 2012.

The prognosis for the Barnett play is for falling production as wells drilled but not yet completed are worked off. The current rig count is only about a third of what is required to offset the 30 percent/year field decline. Barring a major ramp-up in drilling propelled by much higher gas prices, production will fall significantly.

Marcellus Shale Gas Play

The Marcellus shale play of Pennsylvania and West Virginia underlies a wide area including New York and Ohio and has been growing very rapidly in gas production with generally minor production of liquids. Production as of December 2011, totaled 4.96 bcf/d from 3,848 wells along with 5.36 Kbbls/d of liquids. Preliminary data show that gas production may have risen to 5.45 bcf/d by June 2012, making the Marcellus the third-largest shale gas play in the United States. Figure 53 illustrates the growth in gas production.

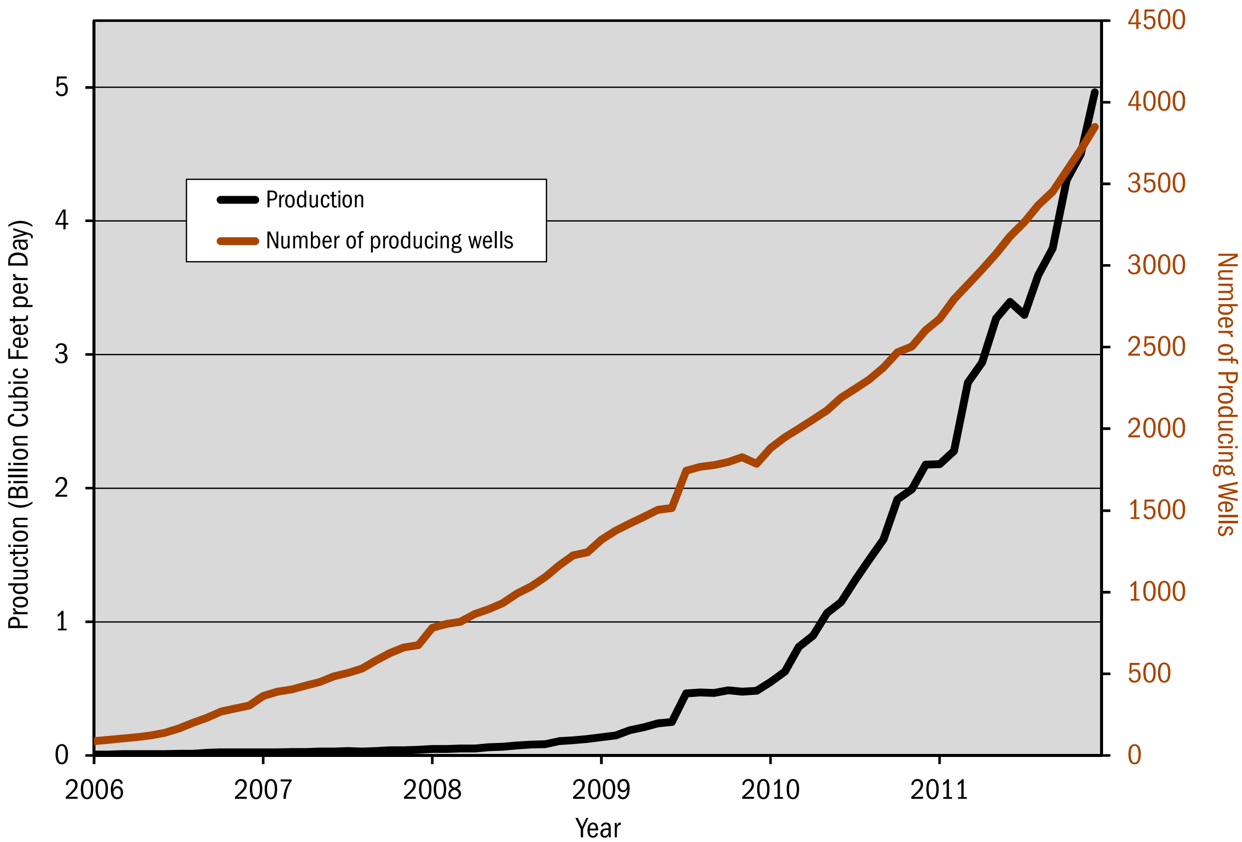

Figure 53. Shale gas production and number of producing wells for the Marcellus shale play, 2006 through December 2011.[99]

The steep growth in production during and after 2009 reflects the application of multi-stage horizontal fracturing technology.

[99] Data from DI Desktop/HPDI current through May, 2012.

The Marcellus is a young play with respect to the application of horizontal, multi-stage, hydraulic-fracturing, even compared to the Haynesville, so production is rising rapidly and some of the drilling statistics are based on less data than would ideally be desired. The type well decline curve illustrated in Figure 54 shows a 95 percent decline rate over the first three years. Operators cite EURs in the 4 to 10 bcf range[100] for the Marcellus, whereas the EIA estimates a mean EUR of 1.56 bcf[101] and the USGS reports a mean EUR of 1.16 bcf.[102] Estimates of breakeven prices for the Marcellus range from $3.81/mcf[103] or less to $7/mcf[104] or more. From this it is evident that most wells in the Marcellus are marginally- or non-economic at current gas prices ($3.30/mcf).

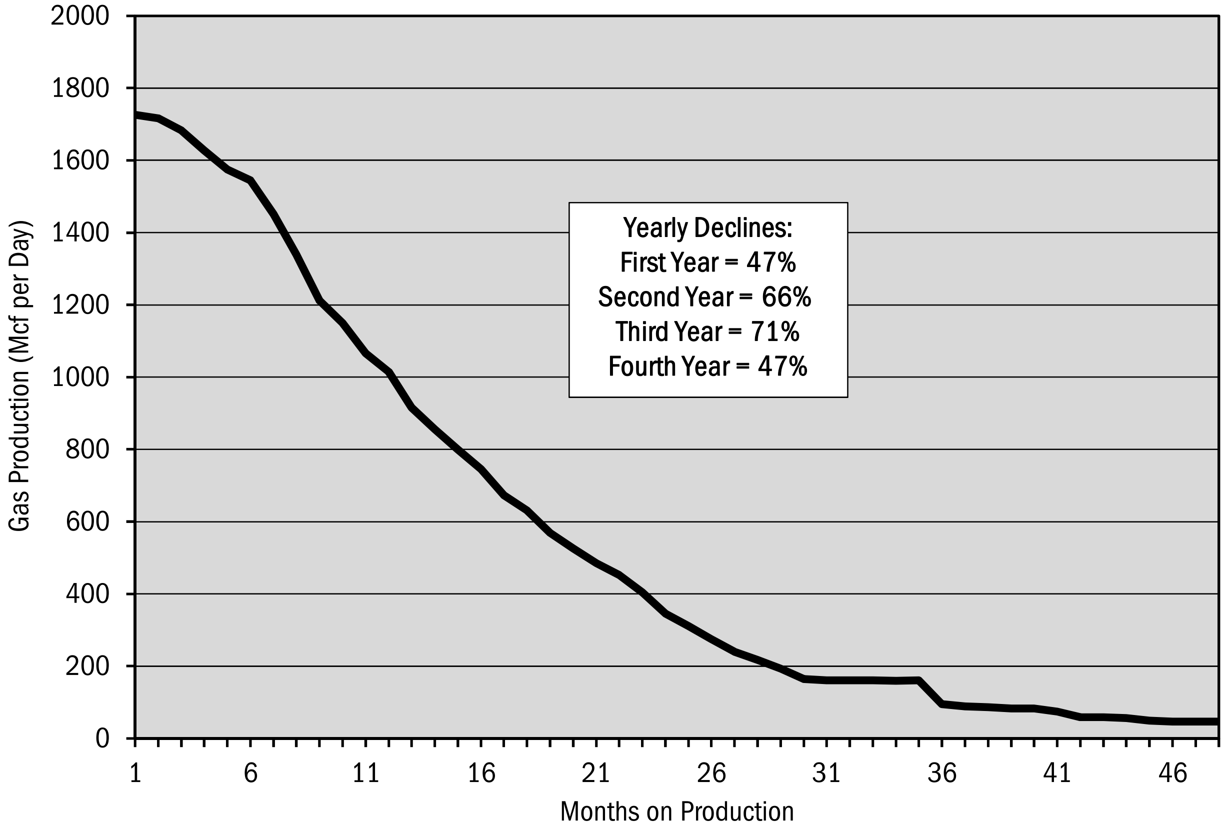

Figure 54. Type decline curve for Marcellus shale gas wells.[105]
Based on data from the most recent four years of this play's production.

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[100] Arthur Berman and Lynn Pittinger, "U.S. Shale Gas: Less Abundance, Higher Cost," The Oil Drum, August 5, 2011, http://www.theoildrum.com/node/8212.
[101] EIA, Annual Energy Outlook 2012, June, 2011, page 59, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[102] United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.
[103] ITG Investment Research, "U.S. Energy Reserves More than Double Official Estimates," October 8, 2012, http://www.prnewswire.com/news-releases/itg-investment-research-us-energy-reserves-more-than-double-official-estimates-173100801.html.
[104] Arthur E. Berman, "U.S. Shale Gas: Magical Thinking and the Denial of Uncertainty," January 18, 2012, Presentation at James A. Baker Institute for Public Policy, http://www.bakerinstitute.org/files/documents/event-presentations/north-american-energy-resources-summit-jan-18-2012/Berman_Presentation_Secured.pdf.
[105] Data from DI Desktop/HPDI current through May, 2012.

Well quality in the Marcellus play as indicated by initial well productivity (IP) illustrated in Figure 55 exhibits an unusual pattern compared to other shale plays. Forty percent of wells are of very low quality and are certainly uneconomic, whereas 15 percent have IPs of over four million cubic feet per day, and are likely economic even at current gas prices. This suggests operators are now focusing on the sweet spots developing in the northeast and southwest portions of Pennsylvania (these are well illustrated by Berman[106]). Although the mean IP of all Marcellus wells is 1947 mcf/d, the average well production is now 1,290 mcf/d. The average IP of new wells continues to rise, however, reflecting the relative youth of this play as operators target sweet spots to the exclusion of the broader expanse of the area underlain by the Marcellus.

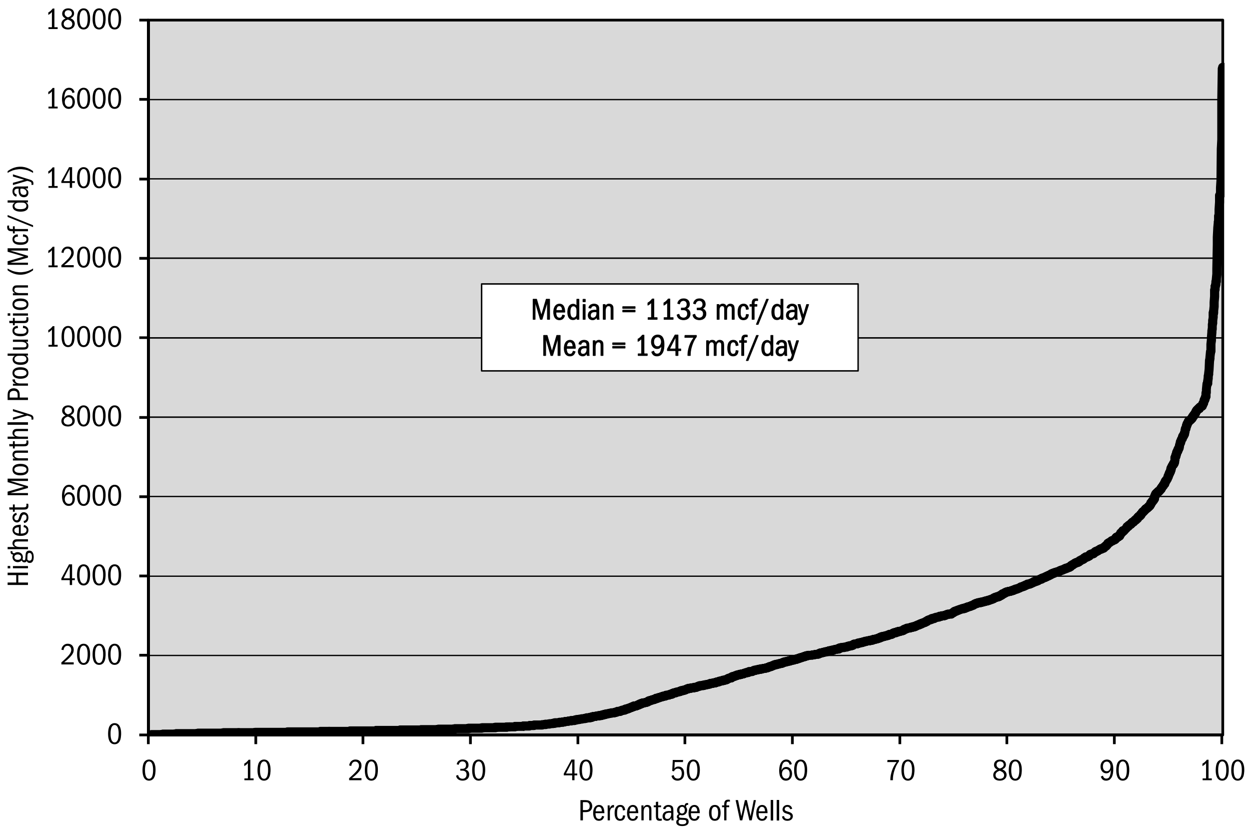

Figure 55. Distribution of well quality in the Marcellus play, as defined by the highest one-month rate of production over well life.[107]

The highest one-month rate of production is typically achieved in the first or second month after well completion.

[106] Arthur E. Berman, "U.S. Shale Gas: Magical Thinking and the Denial of Uncertainty," January 18, 2012, Presentation at James A. Baker Institute for Public Policy, http://www.bakerinstitute.org/files/documents/event-presentations/north-american-energy-resources-summit-jan-18-2012/Berman_Presentation_Secured.pdf.

[107] Data from DI Desktop/HPDI current through May, 2012.

The overall decline rate of the Marcellus play can be estimated from the production from all wells drilled prior to 2011 as illustrated in Figure 56. The yearly overall field decline rate for those wells is about 29 percent, which is equivalent to the Barnett and lower than the Haynesville. Assuming new wells will produce for their first year at the first-year rates observed for wells drilled in 2011, 561 new wells would be required to offset field decline from current production levels each year. At an average cost of $4.5 million per well, this would represent a capital input of about $2.5 billion per year, exclusive of leasing and other infrastructure costs, to keep production flat at today's level.

As of late August 2012,the rig count in Pennsylvania has fallen nearly 45%, but has been maintained in West Virginia and has risen in Ohio. The total rig count of 110 is more than enough to offset declines and will see further growth in production. As of December 2011, wells were being added at a rate of 1,244 per year. Furthermore, there appear to be several hundred wells which have been drilled but not yet connected to a collection system.[108]

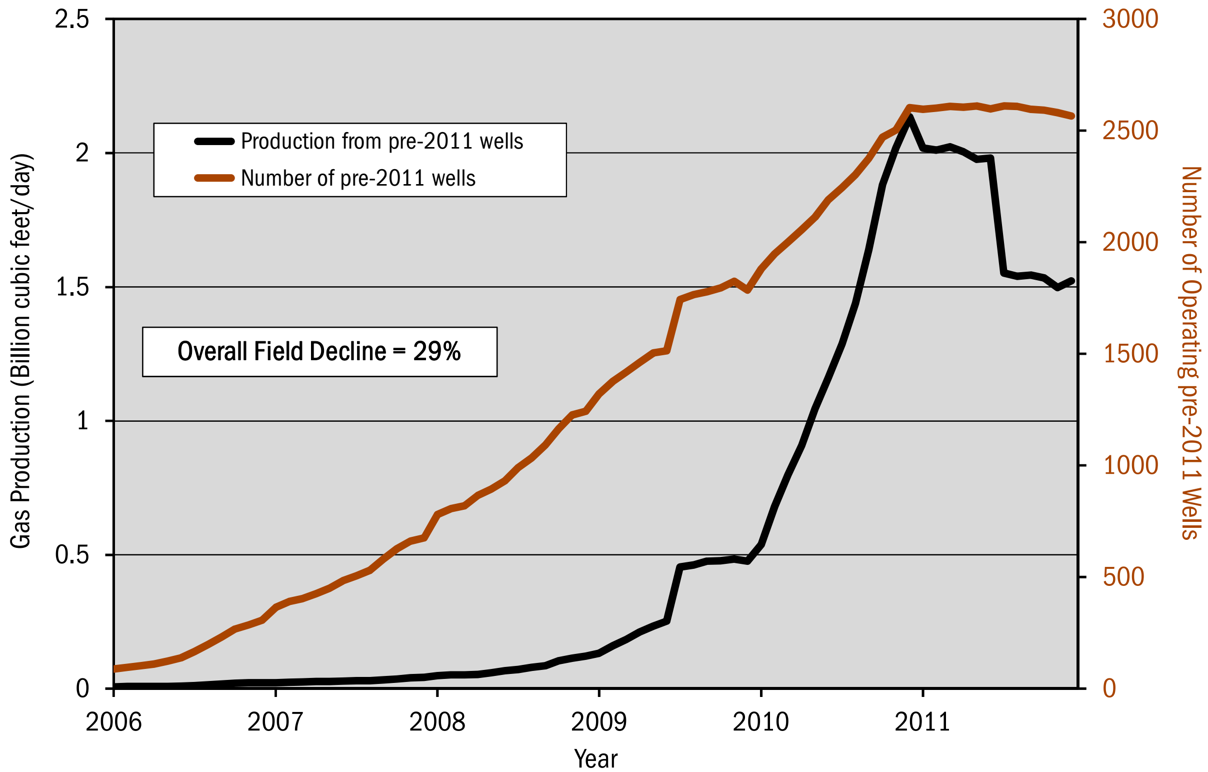

Figure 56. Overall field decline for the Marcellus play based on production from wells drilled prior to 2011.[109]

In order to offset the 29 percent decline rate for the field, 561 new wells producing at 2011 rates are required.

[108] Pennsylvania Department of Environmental Protection, 2012, Jan – June 2012 (Unconventional wells), https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/DataExports/ExportProductionData.aspx?PERIOD_ID=2012-1.
[109] Data from DI Desktop/HPDI current through May, 2012.

Figure 57 illustrates the distribution of drilling in the Marcellus including the core areas defined by the highest well quality. Figure 58 illustrates the highest-quality wells in northeast and southwest Pennsylvania and West Virginia. The IPs of new Marcellus wells are growing, suggesting that operators have delineated and are now focusing on the highest-quality areas. Access and public pushback due to concerns about the environmental impacts of hydraulic fracturing ("fracking") will likely provide some constraints to the wholesale expansion of drilling in these areas.

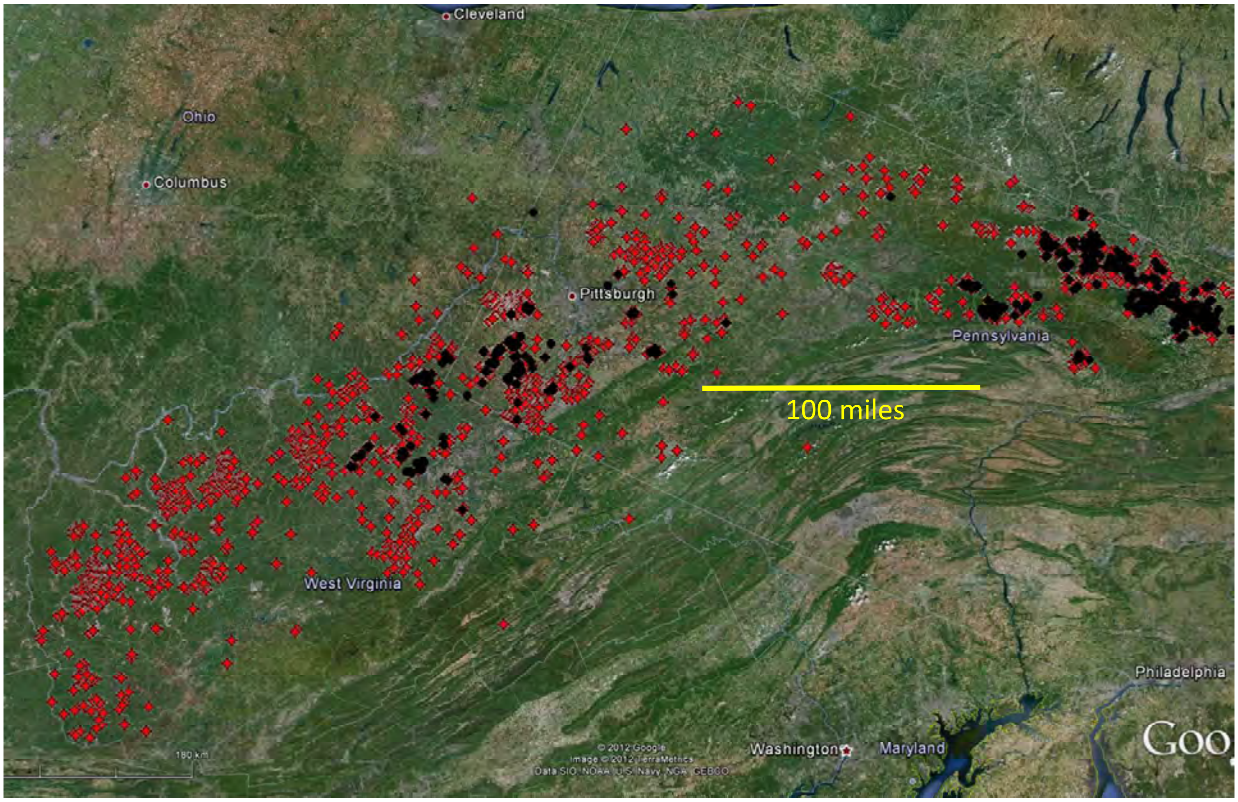

Figure 57. Distribution of wells in the Marcellus play.[110]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells. The highest-productivity wells tend to be concentrated in "sweet spots."

[110] Data from DI Desktop/HPDI current through May, 2012.

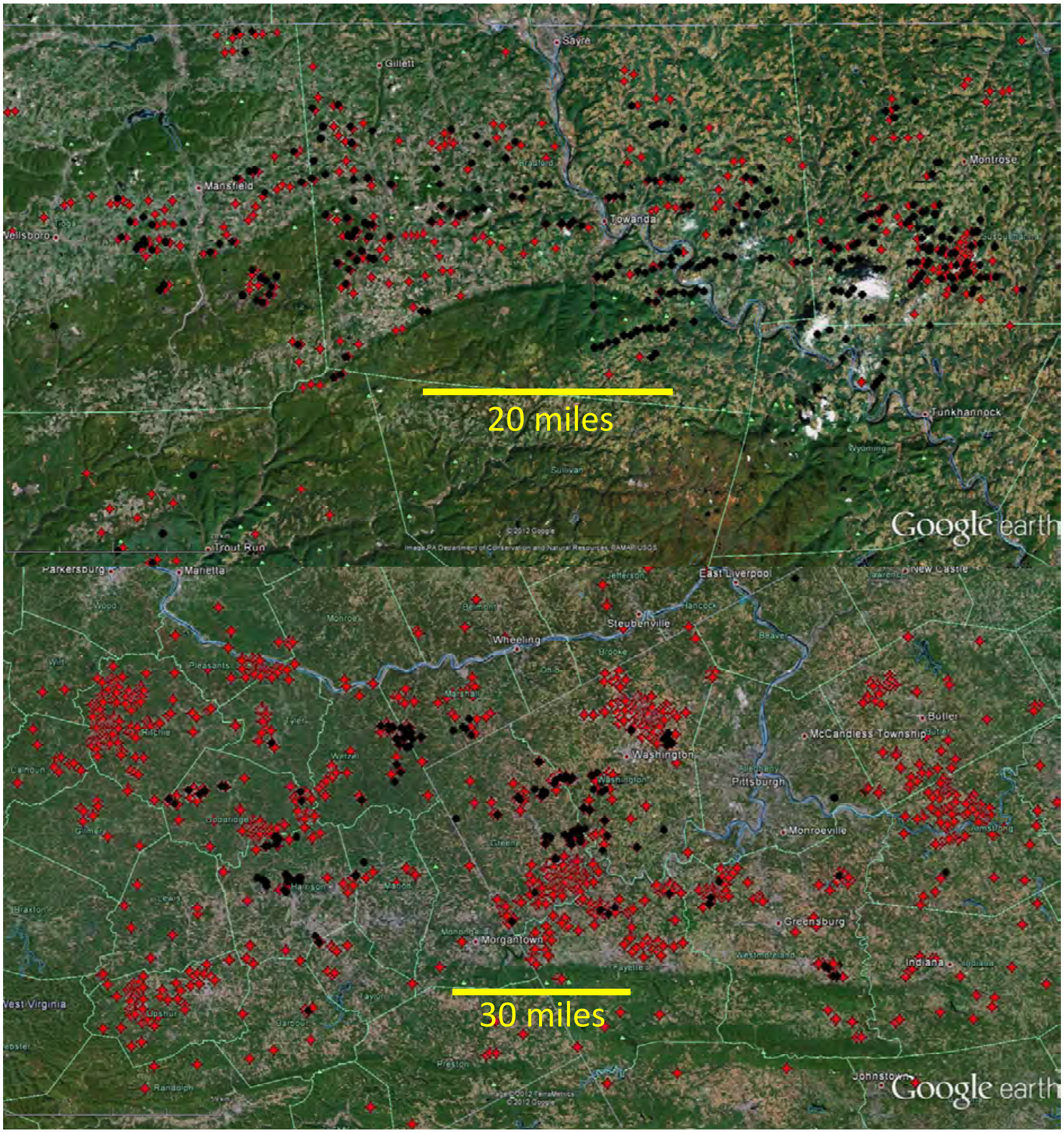

Figure 58. Distribution of wells in the Marcellus play's areas of highest concentration.[111]
Illustrated are northeast Pennsylvania (top) and southwest Pennsylvania and West Virginia (bottom). Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells.

The prognosis for the Marcellus play is for continued growth, as rig counts are far in excess of that required to overcome field declines. The play covers a vast area although clearly only a small portion of it is highly productive. This, along with the increasingly strident public opposition to hydraulic fracturing, will limit the ultimate contribution of this play, although it is likely to become the number-one shale producer as production from the Haynesville and Barnett plays declines over the next few years.

111 Data from DI Desktop/HPDI current through May, 2012.

Other Shale Gas Plays

In all, thirty shale plays were analyzed in all for this report utilizing the parameters for the three plays examined in detail above. A summary of key statistics for all shale gas plays is included in Table 1.

The top three shale gas plays discussed above comprise 66 percent of total shale gas production. The next three—the Fayetteville, Eagle Ford and Woodford plays—add a further 22 percent. The remaining 24 shale plays, which cover much of the EIA's shale play map (Figure 39), contribute only 12 percent of production.

Shale gas production in the United States peaked in December 2011, and is now on an undulating plateau, as illustrated in Figure 59. Rising production in the Marcellus and Eagle Ford is offsetting declines in the Haynesville and Woodford plays, with the Fayetteville and Barnett plays essentially flat. The uniqueness of these plays can be seen in Table 1 with their generally high average well production and high well quality (mean IP) compared to the remaining 24 plays, which often are assumed to have the same potential for growth in production (rate of supply). This is unlikely to be the case, as these plays are generally of much lower quality.

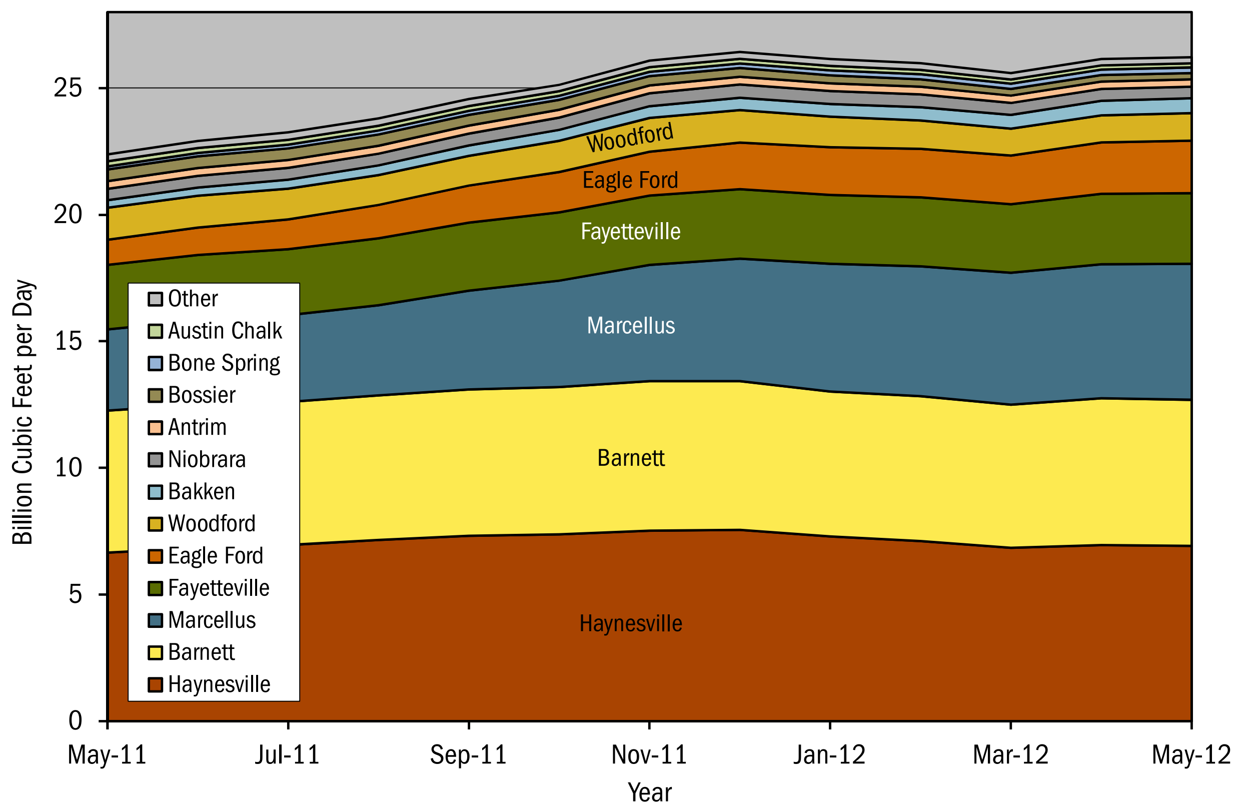

Figure 59. Shale gas production by play, May 2011 through May 2012.[112]

Shale gas production clearly peaked in December 2011 and is now on an undulating plateau. (See Figure 40 for production since 2000.)

[112] Data from DI Desktop/HPDI current through May, 2012, fitted with three month moving average.

Field	Rank	Production (bcf/d)	Month	Number of Operating Wells	Average Well Production (mcf/d)	Mean IP (mcf/d)	Median IP (mcf/d)	IP Trend	First year well decline (%)	Overall annual field decline pre-2011 (%)	Number of Wells needed annually to offset decline	Production Trend	Percent of Total Shale Gas Production
Haynesville	1	6.99	May-12	2802	2493	8201	7954	Declining	68	52	774	Declining	25.76
Barnett	2	5.85	May-12	14871	393	1619	1332	Flat	61	30	1507	Flat	21.56
Marcellus	3	4.96	Dec-11	3848	1290	1947	1133	Rising	47	29	561	Rising	18.28
Fayetteville	4	2.81	May-12	3873	818	2069	1985	Flat	58	36	707	Flat	10.36
Eagle Ford	5	2.14	Jun-12	3129	685	1920	1330	Declining	59	43	945	Rising	7.90
Woodford	6	1.13	May-12	1827	620	2292	1380	Declining	58	29	222	Declining	4.16
Granite Wash	7	0.95	Jun-12	3090	308	2080	1354	Declining	78	49	239	Declining	3.50
Bakken	8	0.60	May-12	4598	122	345	241	Rising	56	29	699	Rising	2.21
Niobrara	9	0.48	May-12	10811	45	162	123	Declining	56	26	1111	Flat	1.77
Antrim	10	0.29	May-12	9409	31	634	102	Flat	*	*	~400	Declining	1.07
Bossier	11	0.25	Jun-12	278	901	9116	3909	Declining	63	38	21	Declining	0.92
Bone Spring	12	0.23	May-12	1016	223	596	258	Flat	58	45	206	Rising	0.84
Austin Chalk	13	0.16	Jun-12	928	169	2109	370	Declining	72	35	127	Declining	0.59
Permian Del. Midland	14	0.088	Jun-12	1541	57	255	91	Rising	34	26	122	Flat	0.326
Lewis	15	0.0523	May-12	462	113	656	427	*	*	*	*	Declining	0.193
Mancos Hilliard Baxter	16	0.05	May-12	452	120	452	182	Declining	63	35	41	Flat	0.184
Spraberry	17	0.031	Jul-12	552	56	210	67	Flat	*	*	*	Rising	0.114
Miss. Lime	18	0.024	Apr-12	371	66	394	109	Rising	39	14	10	Flat	0.088
Bend	19	0.02	Jun-12	273	69	585	336	*	*	*	*	Declining	0.070
Pearsall	20	0.0060	Jun-12	17	309	*	*	*	*	*	*	Declining	0.022
Utica	21	0.006	Dec-11	13	467	478	34	*	*	*	*	Rising	0.022
Hermosa	22	0.0057	May-12	33	180	2549	1888	*	*	*	*	Declining	0.021
Pierre	23	0.004	Apr-12	193	20	126	105	*	*	*	*	Declining	0.015
Tuscaloosa	24	0.0025	May-12	23	110	1474	0	*	*	*	*	Declining	0.009
Manning	25	0.0018	May-12	45	41	903	246	*	*	*	*	Declining	0.007
New Albany	26	0.0017	Dec-09	28	62	101	18	*	*	*	*	Declining	0.006
Mulky	27	0.0015	May-12	120	12.4	50	34	*	*	*	*	Declining	0.006
Chattanooga	28	0.001	Dec-10	107	9	46	29	*	*	*	*	Declining	0.004
Mowry	29	0.0006	Jun-12	39	15	165	20	*	*	*	*	Declining	0.002
Cody	30	0.0004	Jun-12	11	40	334	0	*	*	*	*	Declining	0.002

Table 1. Shale gas play key statistics on production, well quality, and decline rates for the 30 shale gas plays analyzed in this report.[113]

[113] Compiled from an analysis of DI Desktop/HPDI data.

Analysis

Despite the relative youth of shale gas, a pattern emerges in the evolution of individual plays:

- A play is identified and a leasing frenzy ensues.
- A drilling boom to hold leases follows as lease agreements typically include "held-by-production" arrangements which mandate drilling. Leases typically have primary terms of three to five years.
- The first wave of drilling defines "sweet spots," or areas of highest productivity, as well as the extents of the play. Large leaseholders cash out of their worst land by selling to anxious would-be producers.
- The drilling boom causes production to rise rapidly. Drilling shifts to focus on the sweet spots—this is evidenced by rising IPs over time, which is pronounced in the early life of all shale plays.
- Application of "better" technology, such as longer horizontal laterals with more hydraulic-fracturing stages, serves to maintain IPs even as drilling moves away from sweet spots (as they become saturated with wells) to lower quality parts of a play.
- Eventually, better technology cannot make up for lesser-quality geology, and IPs of new wells decline. (This is the case with the Haynesville, still the most productive shale gas play in the United States. IPs are declining in four of the five plays that make up 80 percent of U.S. shale gas production.)
- As IPs decrease, more and more wells are required to offset overall field declines, and without massive amounts of new drilling the plays go into terminal decline.

The Haynesville, Barnett, Fayetteville, and Woodford plays, which collectively produce 68 percent of United States shale gas, are late-middle-aged in terms of the life cycle of shale plays. Unless there is a substantial increase in gas price and a large ramp-up in drilling, these plays will go into terminal decline. The prognosis for the top nine shale plays in the United States, which account for 95 percent of shale gas production, is presented in Table 2.

Field	Rank	Number of Wells needed annually to offset decline	Wells Added for most recent Year	October 2012 Rig Count	Prognosis
Haynesville	1	774	810	20	Decline
Barnett	2	1507	1112	42	Decline
Marcellus	3	561	1244	110	Growth
Fayetteville	4	707	679	15	Decline
Eagle Ford	5	945	1983	274	Growth
Woodford	6	222	170	61	Decline
Granite Wash	7	239	205	N/A	Decline
Bakken	8	699	1500	186	Growth
Niobrara	9	1111	1178	~60	Flat

Table 2. Prognosis for future production in the top nine shale gas plays in the United States.

These plays constitute 95 percent of shale gas production. Note that the Granite Wash is technically a tight sand play and not a shale play, although it is sometimes termed as such.

The Marcellus play is in its youth, and production will grow substantially. The sweet spots have now been identified, and IPs are rising as drilling is focused on these areas. It is only a matter of time, however, until available locations in these areas become saturated and the Marcellus moves into middle age.

Similarly, growth in shale gas production in the Eagle Ford and Bakken plays is strong (in these plays, gas is produced in association with oil, which is the main target). IPs for gas are declining in the Eagle Ford, however, as operators focus on oil production. Much of the gas produced in the Bakken is flared as there is a lack of infrastructure to utilize it.

It is unlikely that the Marcellus, Bakken, and Eagle Ford can offset declines in the major shale gas plays going forward unless there is a substantial increase in gas price and drilling. The approximate investment in drilling required to maintain current production levels in the top 14 plays, which account for over 99 percent of shale gas production, is $41.8 billion annually (Table 3). This does not include leasing costs or the costs of other infrastructure such as pipelines and roads, etc. This cost, and the number of new wells required annually, will increase going forward as the sweet spots are exhausted and drilling moves into lower-quality areas. By comparison, the value of all shale gas produced in the U.S. in 2012 was approximately $32.5 billion dollars at current prices of $3.40 per mcf—a minimum of $9.3 billion *less* than what is required to maintain production.

Field	Rank	Number of Wells needed annually to offset decline	Approximate Well Cost (million $US)	Annual Well Cost to Offset Decline (million $US)
Haynesville	1	774	9.0	$ 6,966
Barnett	2	1507	3.5	5,275
Marcellus	3	561	4.5	2,525
Fayetteville	4	707	2.8	1,980
Eagle Ford	5	945	8.0	7,558
Woodford	6	222	8.0	1,776
Granite Wash	7	239	6.0	1,434
Bakken	8	699	10.0	6,990
Niobrara	9	1111	4.0	4,444
Antrim	10	~400	0.5	200
Bossier	11	21	9.0	189
Bone Spring	12	206	3.7	762
Austin Chalk	13	127	7.0	889
Permian Delaware Midland	14	122	6.9	842
Total		**7641**		**$ 41,829**

Table 3. Estimated annual drilling costs to maintain shale gas production in the top 14 plays.

Note that the Granite Wash is technically a tight sand play and not a shale play, although it is sometimes termed as such.

There is a great deal of industry hype about the prospects of some of the 24 shale gas plays that currently constitute less than 12 percent of shale gas production. Considering the attributes of most of these plays documented in Table 1, such claims appear to be merely hype. The best shale plays are not ubiquitous—they are at the top of their own pyramid as illustrated in Figure 37 with many lesser quality plays below them. Their *rate of supply* is dependent on very large and continuous inputs of capital for drilling, along with progressively escalating collateral environmental impacts—which is the subject of the following section. The marginal to uneconomic nature of most shale gas production and the gas boom responsible for it was reviewed in a comprehensive October 2012 article in *The New York Times.*[114]

As for shale gas resources, the EIA has recently revised its estimate of unproved technically recoverable resources downward by 42 percent to 482 trillion cubic feet (tcf), of which the Marcellus comprises 29 percent or 141 tcf.[115] Notwithstanding the fact that *rate of supply* is a more critical parameter than purported resource estimates, 482 tcf represents just 20 years of supply at 2011consumption rates.

[114] C. Krauss and E. Lipton, "After the Gas Boom", October 20, 2012, *New York Times*.

[115] EIA, 2012, Annual Energy Outlook 2012, page 57, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

Adding 2010 proved reserves of 97.5 tcf[116] raises the total shale gas resource to 24 years of current consumption. Nevertheless, shale gas continues to be heralded as the main underpinning of the "one hundred years of gas" rhetoric.

The EIA goes on to estimate the level of effort that will be required to recover the unproved resource in terms of the number of available well locations left to drill, along with estimated mean EURs, as illustrated in Table 4.[117] The EIA estimates that 410,722 wells will be required to recover the estimated 482 tcf of shale gas. The law of diminishing returns is well illustrated in this table. Sixty-six percent of the resource, or 319 tcf, require 44 percent of the wells to recover. The remaining 33 percent of the resource requires 56 percent of the wells—roughly two and a half times as many wells per unit of resource extracted. The implied EUR for the "other" category in Table 4 is 0.71 bcf per well, a level that is well below the economic threshold at current gas prices. Furthermore, if published USGS mean technically recoverable resource estimates and mean EURs are utilized to determine resource volumes, unproved shale gas resources reduce to 378 tcf. This is equivalent to 16 years of current United States gas consumption.

The net energy (or EROEI) of natural gas has been calculated by Skone et al. at 7.6:l.[118] This includes the energy inputs for drilling, extraction, and transport for all domestic gas production compared to the energy delivered. Shale gas is more energy intensive than conventional gas due to the nature of the hydraulic-fracturing process, which involves handling and disposing of millions of gallons of water, several hundred heavy truck trips per well, very high pressures for fluid injection, and so forth. Thus the EROEI for shale gas will be substantially lower than 7.6:1, perhaps 5:1 or less on average, although there have been no definitive studies. Furthermore, the EROEI of shale gas can be expected to decline over time as evidenced by the EIA estimates of the number of wells required to extract it discussed above.

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116 EIA, 2012, Table 3 - Principal shale gas plays: natural gas production and proved reserves, 2008-2010, http://www.eia.gov/naturalgas/crudeoilreserves/.

117 EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

118 Skone et al., "Role of Alternative Energy Sources: Natural Gas Power Technology Assessment," National Energy Technology Laboratory, June 30, 2012, page 52-53, http://www.netl.doe.gov/energy-analyses/pubs/NGTechAssess.pdf.

	EIA Number of Potential Wells	EIA Mean EUR (bcf/well)	EIA TRR (tcf)	USGS Mean EUR (bcf/well)	TRR using USGS EUR or USGS published estimates (tcf)
Marcellus	90216	1.56	141	0.129-1.158	84
Utica	13936	1.13	16	0.128-.619	38
Woodford-Arkoma	5428	1.97	11	0.446-1.23	7
Fayetteville	10181	1.3	13	1.104	11
Chattanooga	1633	0.99	2	0.223	0.4
Caney	3369	0.34	1	0.179	1
Haynesville/Bossier	24627	2.67	66	1.308-2.617	64
Eagle Ford	21285	2.36	50	1.104	23
Pearsall	7242	1.22	9	0.391	3
Woodford-Anadarko	3796	2.89	11	1.23	18
Subtotal	181713		319		250.4
Other	229009	0.712	163		128
Total	410722		482		378.4

Table 4. U.S. shale gas potential wells and resources, EIA estimates versus USGS estimates.

This table shows EIA estimates of potential wells in various shale gas plays, as well as EIA estimates of shale gas unproved technically recoverable resources (TRR)[119] compared to USGS estimates either from published sources[120] or calculated from published USGS estimates of maximum EUR[121]. The estimates from the USGS are approximately 78 percent of the EIA estimates; applying this percentage reduction to the EIA's "other" category yields a total USGS estimate of 378 tcf.

119 Ibid.

120 Mean USGS estimates for the Marcellus shale are from http://energy.usgs.gov/Miscellaneous/Articles/tabid/98/ID/102/Assessment-of-Undiscovered-Oil-and-Gas-Resources-of-the-Devonian-Marcellus-Shale-of-the-Appalachian-Basin-Province.aspx; for the Utica shale are from http://energy.usgs.gov/Miscellaneous/Articles/tabid/98/ID/200/Assessment-of-undiscovered-oil-and-gas-resources-of-the-Ordovician-Utica-Shale-of-the-Appalachian-Basin-Province-2012.aspx; and for the Woodford-Anadarko are from http://pubs.usgs.gov/of/2011/1242/.

121 United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.

Environmental Considerations

There has been huge pushback by citizen groups against the environmental impacts of hydraulic-fracturing for shale gas. Concerns focus on:

- Methane contamination of groundwater, along with possible contamination of groundwater by fracturing fluids.[122],[123]
- Disposal of produced fracture fluid contaminating groundwater and inducing earthquakes, as well as earthquakes triggered by hydraulic fracturing itself.[124]
- Industrial footprint: drilling pads, roads, truck traffic (up to 1,975 heavy truck and 1,420 light truck round trips per well), air emissions and noise from compressors etc.[125]
- High water consumption: between two and eight million gallons per well.
- Full cycle greenhouse gas emissions which may be worse than coal.[126]

These concerns have so far not limited drilling in states that permit it, but they have resulted in moratoriums in New York, Maryland, and the Province of Quebec in Canada. The United States Environmental Protection Agency is conducting an extensive review of hydraulic fracturing with a final report due in 2014. It is beyond the scope of this report to conduct a detailed review of these issues, other than to say that they are very real and will certainly impact the ability of shale gas drillers to access locations which will further impact future shale gas production. There is no free lunch, and the collateral environmental impact of shale gas drilling will accelerate going forward as industry attempts to compensate for the steep declines in existing fields. [127]

[122] Stephen G. Osborn et al., 2011, "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing", http://biology.duke.edu/jackson/pnas2011.pdf.
[123] Ramit Plushnick, "EPA changed course after company protested", Associated Press, January 16, 2013, http://www.nbcnews.com/id/50479081/ns/us_news-environment/.
[124] B.C. Oil and Gas Commission, "Investigation of Observed Seismicity in the Horn River Basin", 2012, http://www.bcogc.ca/document.aspx?documentID=1270.
[125] New York State Department of Environmental Conservation, "Revised Draft SGEIS on the Oil, Gas and Solution Mining Regulatory Program (September 2011): Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing in the Marcellus Shale and Other Low-Permeability Gas Reservoirs", 2011, http://www.dec.ny.gov/energy/75370.html; see in particular Chapters 5, 6A and 6B, and page 6-303 for truck traffic estimates.
[126] Robert W. Howarth et al., 2011, "Methane and the greenhouse-gas footprint of natural gas from shale formations", *Climatic Change* (2011) 106:679–690, http://www.springerlink.com/content/e384226wr4160653/fulltext.pdf?MUD=MP.
[127] Earthworks, "Gas Patch Roulette", October 2012, http://www.earthworksaction.org/files/publications/Health-Report-Full-FINAL.pdf.

Tight Oil (Shale Oil)

KEY TAKEAWAYS

- Tight oil (shale oil) has grown impressively and now makes up about 20 percent of U.S. oil production. This has allowed U.S. crude oil production to reverse years of decline and grow 24 percent above its all-time post-1970 low in 2008.
- As with shale gas, tight oil plays are not ubiquitous. More than 80 percent of tight oil production is from two unique plays: the Bakken and the Eagle Ford. The remaining nineteen plays produced just 19 percent of current tight oil production. There is also considerable variability within these plays, and the highest productivity wells tend to be concentrated within relatively small sweet spots.
- Well decline rates are steep – between 81 and 90 percent in the first 24 months. The plays are too young to assess overall well lifetimes but production rates in the Bakken after five years are 33 bbls/d on average and after seven years will likely approach stripper well status (10 bbls/d). Eagle Ford wells could reach stripper well status within four years.
- Overall field decline rates are such that 40 percent of production must be replaced annually to maintain production. Current drilling rates are far higher than this level hence production is expected to continue to grow rapidly.
- Ultimate recovery of tight oil plays is governed by the number of available drilling locations. The EIA estimates a total of 11,725 locations in the Bakken (including the Three Forks Formation). This is about three times the current number of operating wells. A similar estimate by the EIA puts available locations in the Eagle Ford at more than three times the current number of operating wells.
- Given the EIA estimate of available well locations, the Bakken, which has produced about half a billion barrels to date, will ultimately produce about 2.8 billion barrels by 2025 (close to the low end of the USGS estimate of 3 billion barrels). Similarly, the Eagle Ford will ultimately produce about 2.23 billion barrels, which is close to the EIA estimate of 2.46 billion barrels. Together these plays may yield a little over 5 billion barrels, which is less than 10 months of U.S. consumption.
- The production trajectory of tight oil plays depends on the rate of drilling. If current drilling rates are maintained, tight oil production will grow to a peak in 2016 at about 2.3 mbd assuming the EIA estimates of available locations in the Bakken and Eagle Ford are correct. Production in the Bakken and Eagle Ford will then collapse at overall field decline rates. Assuming production in the other tight oil plays continues to grow at linear rates, tight oil production will be at 0.7 mbd in 2025. This represents a U.S. tight oil production bubble of a little over ten years duration.
- The EIA projections of U.S. tight oil production are very aggressive. They assume that 26 billion barrels, or 78 percent of its estimate of unproved technically recoverable tight oil resources, will be consumed by 2040 2040.

Tight oil, also known as shale oil, has grown in production from virtually nothing in 2004 to current U.S. production of more than one million barrels per day as illustrated by Figure 60. This is oil produced from very low permeability ("tight") source rocks utilizing the same multi-stage hydraulic-fracturing technology in horizontal wells that is used to produce shale gas. The quality of this oil is generally very high and substantial amounts of natural gas are commonly produced in association with the oil.

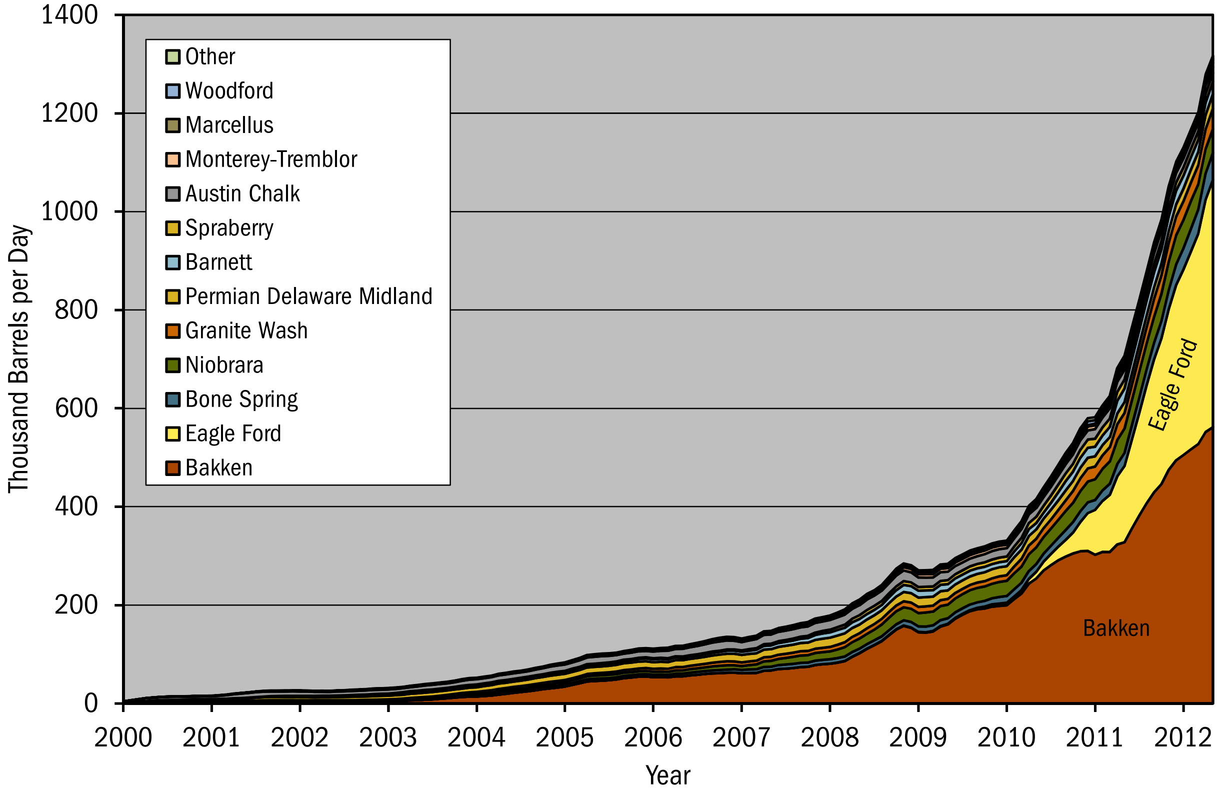

Figure 60. Tight oil production by play. 2000 through May 2012.[128]

Tight oil is often heralded by pundits as the major contributor to potential "energy independence" for the United States. Production began in the Bakken play of Montana and North Dakota and has since grown rapidly in the Eagle Ford play of southern Texas, and to a much lesser extent in nineteen other plays. Together the Bakken and Eagle Ford comprise 81 percent of tight oil production.

[128] Data from DI Desktop/HPDI current through May, 2012, fitted with three month moving average.

Figure 61 illustrates the production of these 21 tight oil plays as of May 2012. As can be seen, the majority of production is concentrated in the top two plays, with the top six constituting 94 percent of production. The bottom fifteen plays collectively contribute just over six percent of production.

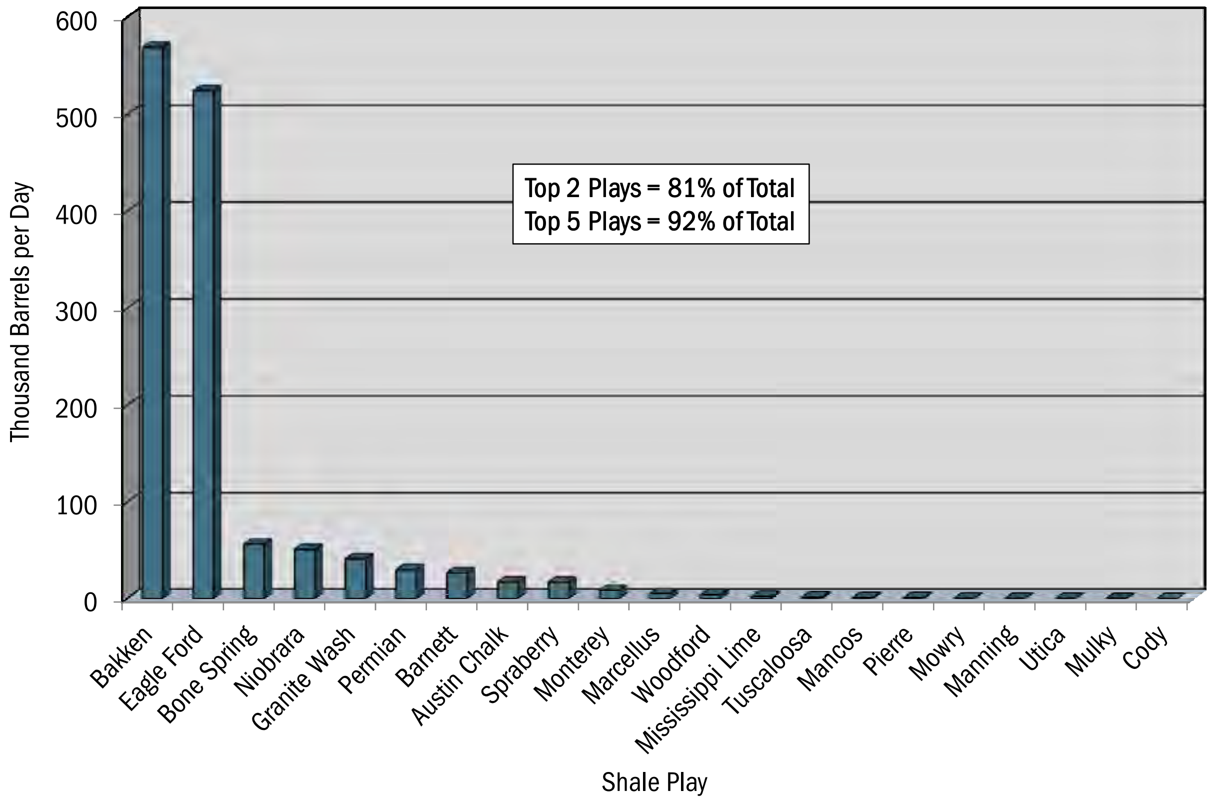

Figure 61. Tight oil production by play, May 2012.[129]

Note that the Granite Wash is technically tight sand, not shale, but is included for information.

As with shale gas plays, tight oil plays with high productivity characteristics are not ubiquitous, and the best of them are relative rarities. There is also considerable variability within tight oil plays ,with smaller sweet spots and larger less productive areas. Furthermore, due to their high decline rates these plays require high levels of capital input for drilling and infrastructure development to maintain production levels. In order to illustrate these points, a more detailed analysis of the top two tight oil plays is offered below.

[129] Data from DI Desktop/HPDI current through May-June, 2012.

Bakken Tight Oil Play

The Bakken was the first tight oil play and is still the most productive tight oil play in the United States. Although the Bakken has been producing at low rates for many decades, the advent of multi-stage hydraulic fracturing in horizontal wells has increased production rapidly. Production is from the Bakken, Three Forks-Sanish, and Nissan reservoirs, hereinafter collectively referred to as the Bakken play. Figure 62 illustrates the growth in both production and the number of producing wells since 2000. Production totaled 568,000 barrels per day from 4,598 operating wells in May 2012. The Bakken is also a prolific producer of associated gas, with production of 0.6 bcf/d in May 2012. Much of this gas is flared due to a lack of infrastructure.[130]

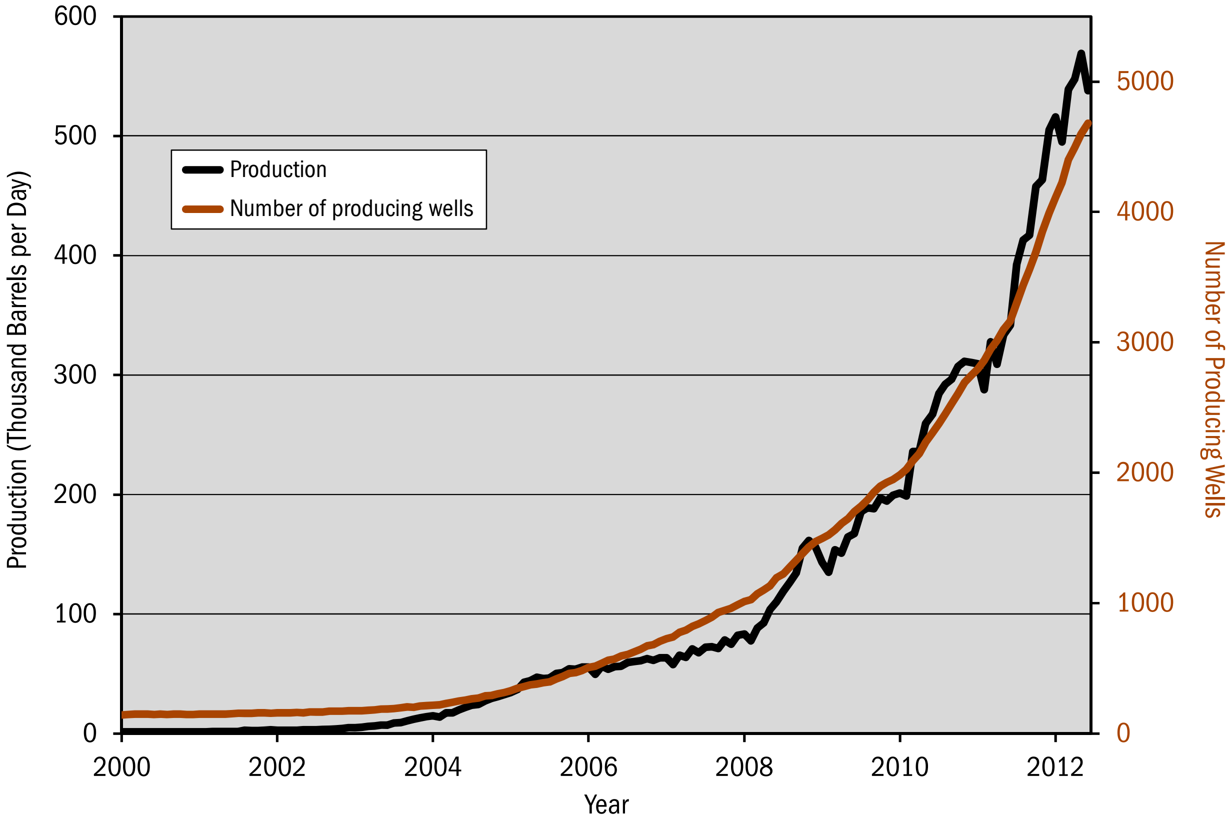

Figure 62. Tight oil production and number of producing wells for the Bakken shale play, 2000 through May 2012.[131]

Bakken wells exhibit steep production declines over time. Figure 63 illustrates a type decline curve compiled from the most recent 66 months of production data. The first year decline is 69 percent and overall decline in the first five years is 94%. This puts average Bakken well production at slightly above the category of "stripper" wells in a mere six years, although the longer term production declines are uncertain owing to the short lifespan of most wells.

The average breakeven price for Bakken oil is the subject of considerable debate. Groups such as ITG suggest it is in the order of $65/bbl.[132], whereas other detailed analyses claim that the cost is more like

[130] "Oil industry wasting 34% of gas produced in rush to extract North Dakota oil", Daily Kos, July 24, 2012, http://www.dailykos.com/story/2012/07/24/1113106/-Oil-industry-wasting-34-of-natural-gas-produced-in-rush-to-extract-North-Dakota-oil.
[131] Data from DI Desktop/HPDI current through May, 2012.

$80-90/bbl.[133] The EUR for the Bakken utilized by the EIA to determine an unproved technically recoverable resource estimate of 5.372 billion barrels is 550,000 barrels per well.[134] The USGS is much more conservative, suggesting that the EUR is highly variable in different parts of the play and ranges from 64,000 to 241,000 barrels per well.[135] By contrast, some industry EUR estimates are up to 1,160,000 barrels per well.[136] Industry estimates of technically recoverable resources for the Bakken, such as Continental Resources Inc.'s estimate of 24.3 billion barrels[137], are also far higher than the EIA's estimate, or the USGS estimate of 3 to 4.3 billion barrels.[138] The credibility of such industry estimates remain in serious doubt.

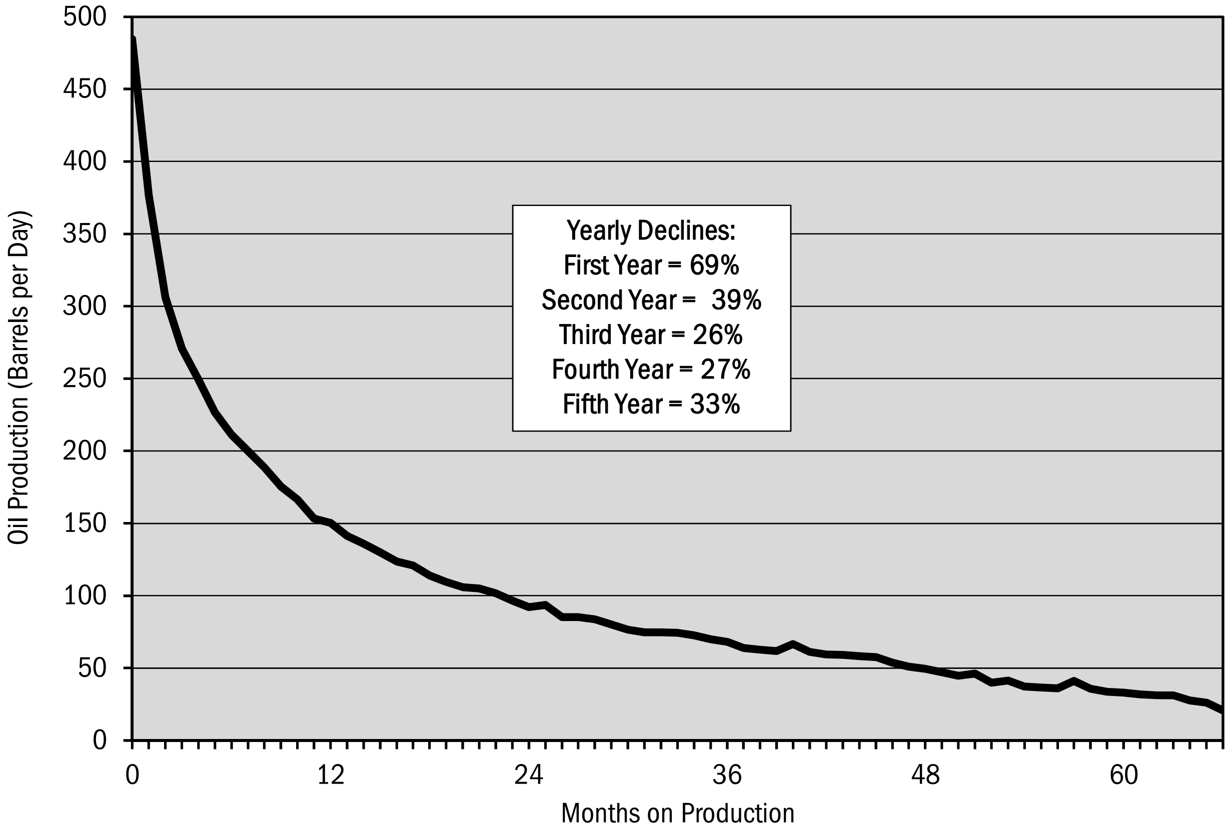

Figure 63. Type decline curve for Bakken tight oil wells[139].
Based on data from the most recent 66 months of this play's oil production.

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132 ITG Investment Research, "U.S. Energy Reserves More than Double Official Estimates," October 8, 2012, http://www.prnewswire.com/news-releases/itg-investment-research-us-energy-reserves-more-than-double-official-estimates-173100801.html.
133 Rune Likvern, "Is Shale Oil Production from the Bakken headed for a Run with the 'Red Queen'?", The Oil Drum, September, 2012, http://www.theoildrum.com/node/9506.
134 EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
135 United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.
136 "QEP Resources Takes Bigger Bite out of Bakken," Seeking Alpha, August 27, 2012, http://seekingalpha.com/article/831381-qep-resources-takes-a-bigger-bite-of-bakken.
137 James Mason, "Bakken's maximum potential oil production rates explored", Oil and Gas Journal, February 4, 2012, http://www.ogj.com/articles/print/vol-110/issue-4/exploration-development/bakken-s-maximum.html.
138 USGS, "3 to 4.3 Billion Barrels of Technically Recoverable Oil Assessed in North Dakota and Montana's Bakken Formation—25 Times More Than 1995 Estimate", April 2008, http://www.usgs.gov/newsroom/article.asp?ID=1911
139 Data from DI Desktop/HPDI current through May, 2012.

The initial productivity (IP) of a well when it is first drilled is one measure of well quality and typically bears some correlation to EUR. Figure 64 illustrates the highest one-month production recorded for wells in the Bakken play. The variability of the wells illustrates the differing geological properties within various parts of the play. The mean IP is 400 bbls/d with very high quality wells at more than 1,000 bbls/d, amounting to less than five percent of the total. The average production of all operating Bakken wells is now 124 bbls/d, because of the effect of steep well declines and the fact that overall field production is from a mix of old and new wells.

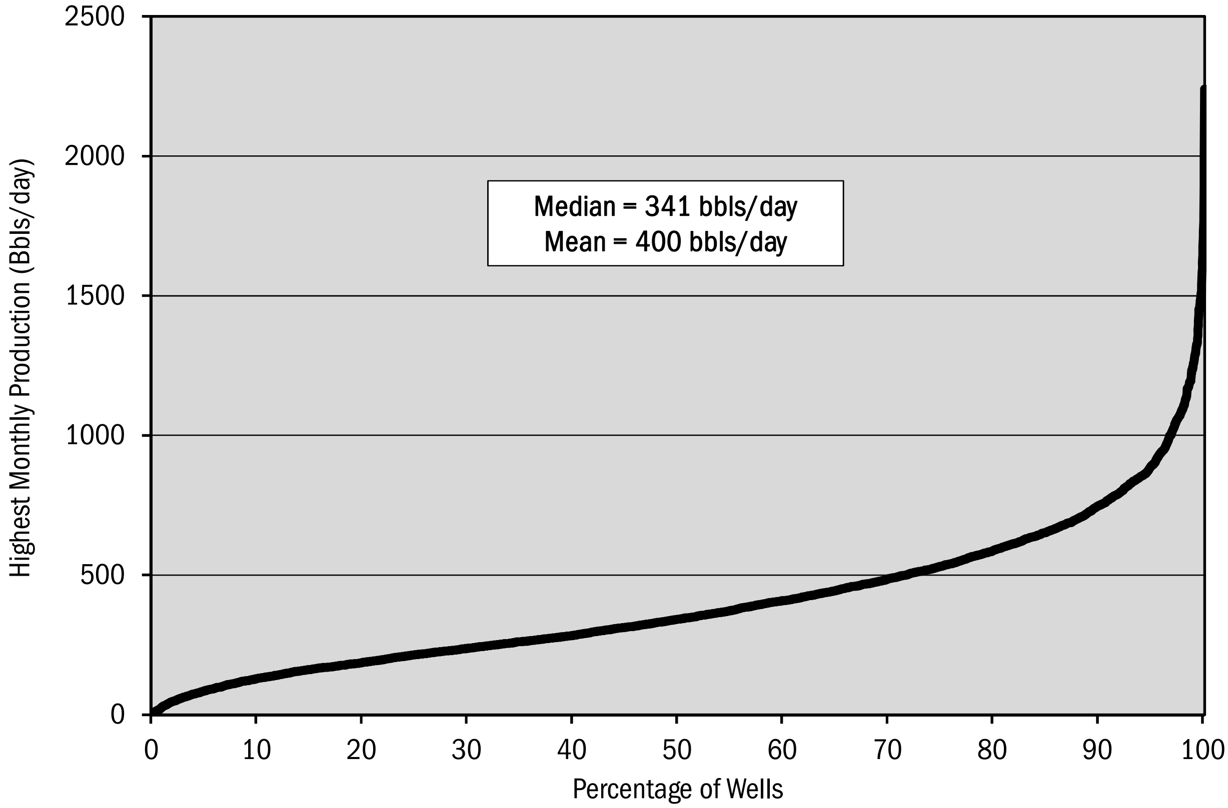

Figure 64. Distribution of well quality in the Bakken play, as defined by the highest one-month rate of production over well life.[140]

The highest one-month rate of production is typically achieved in the first or second month after well completion.

[140] Data from DI Desktop/HPDI current through May, 2012.

The overall decline rate of the Bakken play can be estimated from the production from all wells drilled prior to 2011 as illustrated in Figure 65. The yearly overall field decline rate is about 40 percent. Assuming new wells will produce for their first year at the first-year rates observed for wells drilled in 2011, 819 new wells would be required to offset field decline each year from current production levels. At an average cost of $10 million per well, this would represent a capital input of about $8.2 billion per year, exclusive of leasing and other infrastructure costs, just to keep production flat at today's level. The current rig count in the Bakken is more than sufficient to offset overall field decline. Fifteen hundred new wells were added in the year prior to May 2012, and the current rig count of 186 is sufficient to maintain this rate of drilling. The lack of growth in IP's in new wells indicates that the increases from "better" technology have been achieved and the sweet spots have been located and are being drilled off. These are the symptoms of an early-middle-aged shale play.

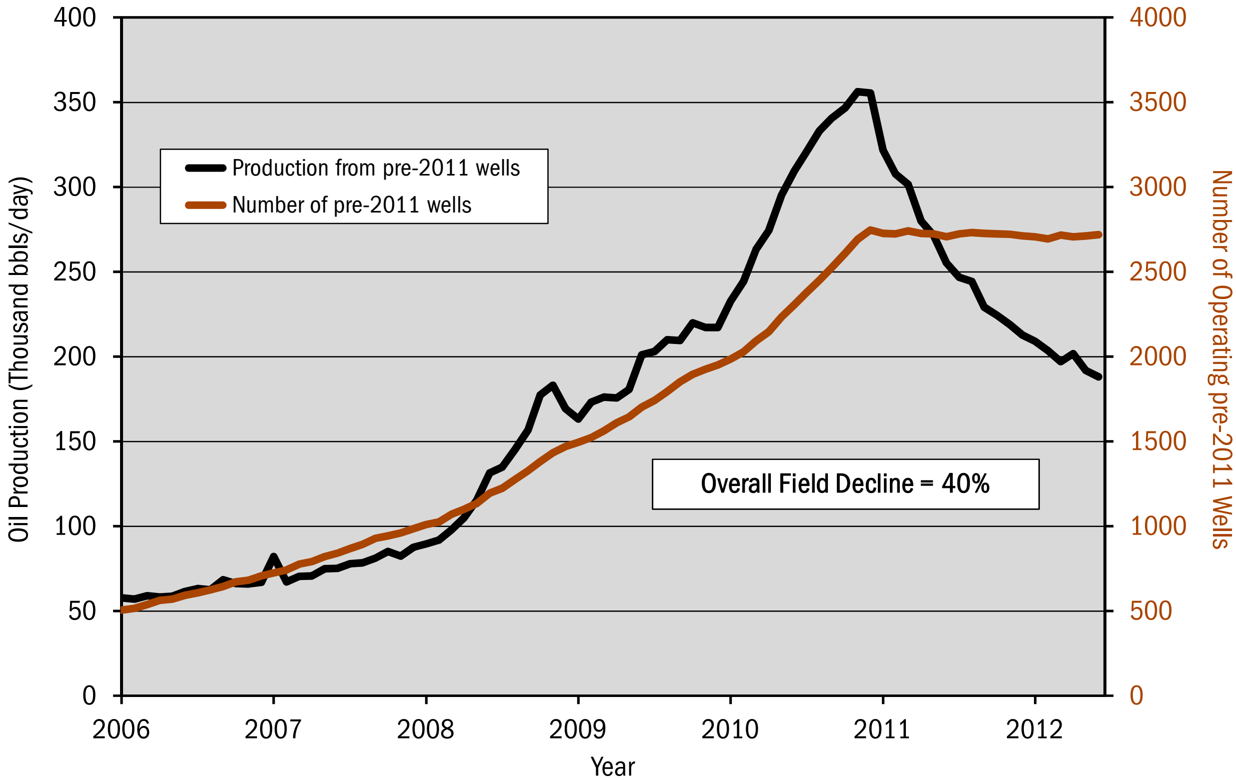

Figure 65. Overall field decline for the Bakken play based on production from wells drilled prior to 2011.[141]

In order to offset the 40 percent decline rate for the field, 819 new wells producing at 2011 rates are required.

[141] Data from DI Desktop/HPDI current through May, 2012.

The question is, how much can Bakken production be increased and for how long? Future production growth is dependent on the number of wells drilled annually, new well performance, and the number of locations available to drill. Assuming that wells can be added at the current rate of 1,500 per year and that new well quality remains at current levels (i.e., first-year production that equals average 2011 first-year levels), the critical parameter governing the production profile of the play becomes the number of available well locations.

The EIA estimates that 9,727 available well locations were left to drill in the Bakken as of January 2010[142]; adding that to the 1,985 wells operating at that time yields a ceiling of 11,725 wells in the Bakken. This yields a production profile which rises 41 percent from May 2012 to a peak of 0.973 million barrels per day in 2017, as illustrated in Figure 66. At this point, with all well locations drilled, production declines at the overall field decline rate of 40 percent. The overall field decline may decrease somewhat over time after peak as wells approach terminal decline rates. Total oil recovery in this scenario is about 2.8 billion barrels by 2025, which agrees fairly well with the lower range of the USGS recoverable estimate of three billion barrels.[143] Average well production falls below 10 bbls/d in this scenario by 2022.

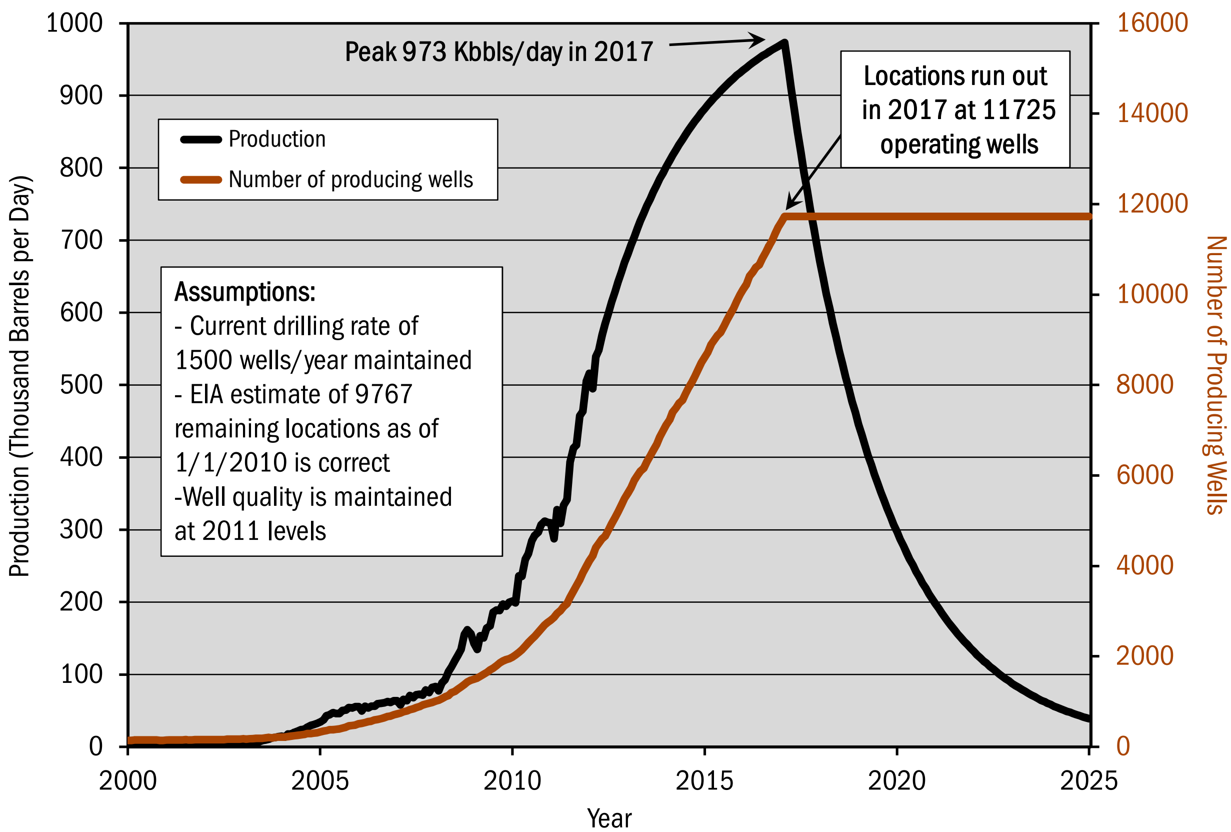

Figure 66. Future oil production profile for the Bakken play, assuming current rate of new well additions.

This scenario assumes constant new well quality and EIA estimate of remaining available well locations. Production declines at the overall field rate of 40 percent after peak in 2017.

142 EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

143 USGS, "3 to 4.3 Billion Barrels of Technically Recoverable Oil Assessed in North Dakota and Montana's Bakken Formation—25 Times More Than 1995 Estimate," April 2008, http://www.usgs.gov/newsroom/article.asp?ID=1911.

The sensitivity to input parameters does not change overall recovery as long as total well locations are held constant at 11,725 and average well quality does not decline. For example, if drilling rates are increased to 2,000 wells per year, the play peaks two years earlier in 2015 at a higher production level of 1.191 million barrels per day, as illustrated in Figure 67.

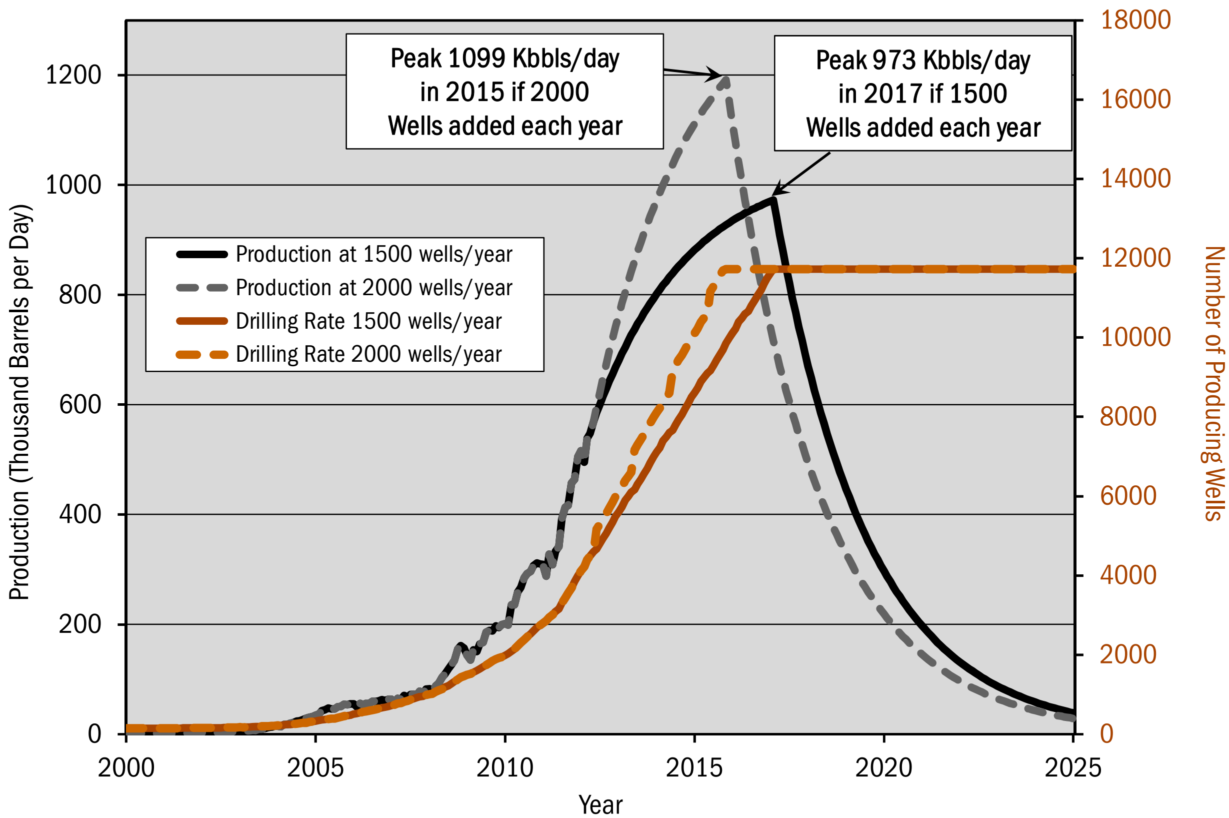

Figure 67. Future oil production profiles for the Bakken play, assuming current rate of well additions compared to a scenario of 2,000 new wells per year.

Both scenarios assume constant new well quality and the EIA estimate of 11,725 total available well locations. Production declines after peak in both scenarios at the overall field rate of 40 percent.

Of course industry would beg to differ. Continental Resources Inc. suggests that there are 38,980 well locations in North Dakota alone (the EIA estimate of 11,725 well locations includes Montana as well).[144] Multiplying these locations by an EUR of 0.5 million barrels per well yields 19.5 billion barrels in North Dakota. Given actual rates of drilling, the observed production variability, and the generally much lower EURs determined by the USGS, such estimates lack credibility, as they assume uniform geology and accessibility over very large areas.

However, for the sake of argument, if one assumes there are 38,980 available locations with drilling at 2012 rates of 1,500 wells per year and that average 2011 first-year production rates per well are maintained indefinitely for new wells, production would rise to 1.014 million barrels per day and plateau until these locations are used up by 2035 (assuming the overall field decline rate of 40%), with a total recovery of 8.8 billion barrels. If drilling rates of 2,000 wells per year are assumed, production would

[144] James Mason, "Bakken's maximum potential oil production rates explored", Oil and Gas Journal, February 4, 2012, http://www.ogj.com/articles/print/vol-110/issue-4/exploration-development/bakken-s-maximum.html.

rise to 1.388 million barrels per day and plateau until these locations are used up in 2029, with a total recovery of 8.45 billion barrels. Thus using their own claim of 38,980 possible well locations, Continental Resources' estimates of 19.5 billion barrels recoverable from North Dakota and 24.3 billion barrels from all of the United States Bakken defy the observed realities of overall field declines and well productivity, and are therefore not credible.

An idea of the existing well saturation and the distribution of the highest-quality wells in the Bakken at this point is illustrated in Figure 68 and Figure 69. EIA estimates of available well locations would see well saturation more than triple; industry estimates would see well saturation grow eight-fold.

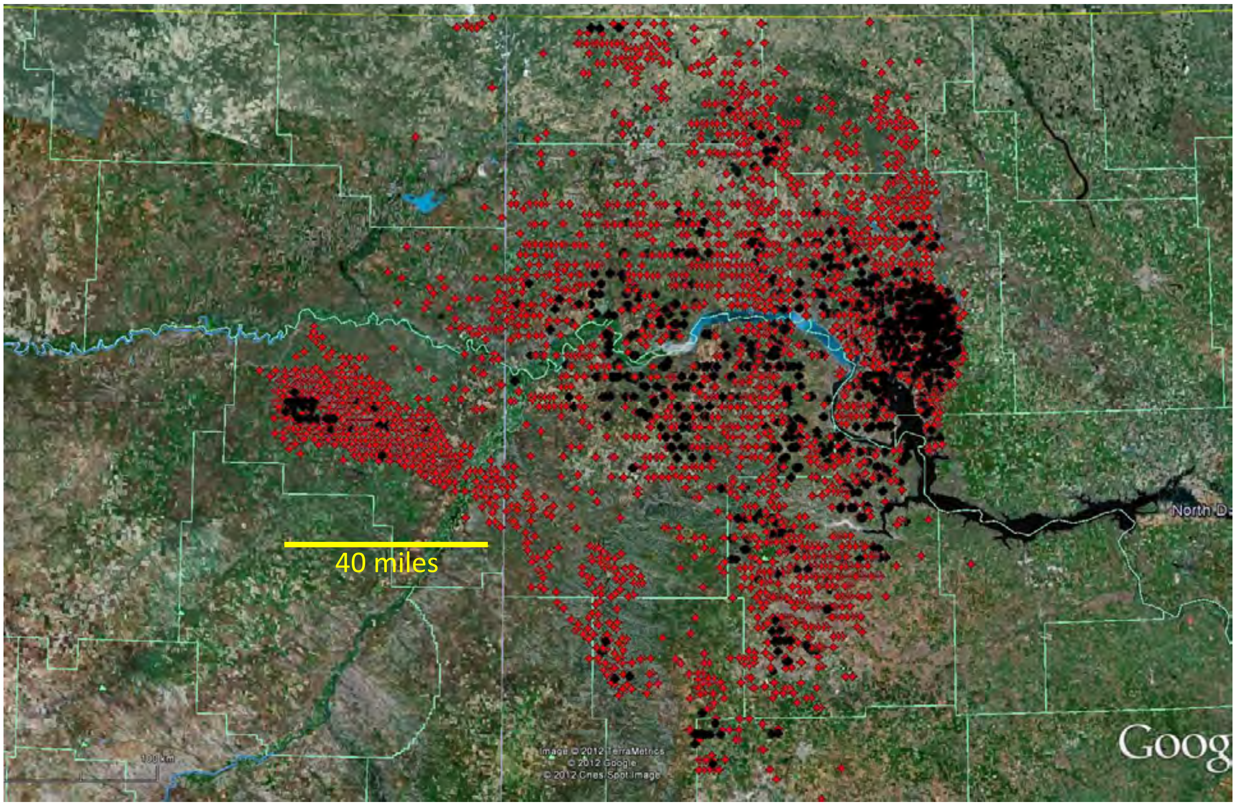

Figure 68. Distribution of wells in the Bakken play.[145]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells. The highest productivity wells tend to be concentrated in in "sweet spots."

[145] Data from DI Desktop/HPDI current through May, 2012.

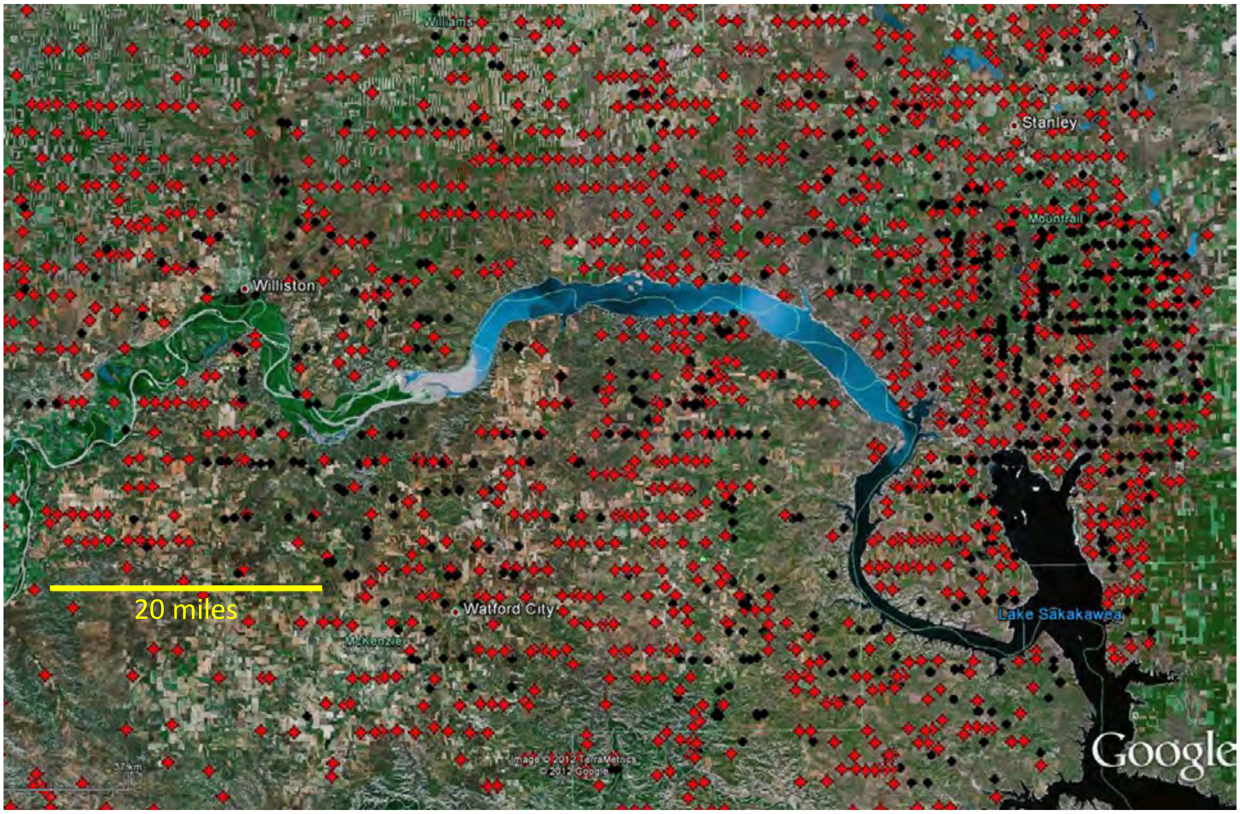

Figure 69. Distribution of wells in the Bakken play's area of highest concentration.[146]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells.

146 Data from DI Desktop/HPDI current through May, 2012.

Figure 70 illustrates the pattern of horizontal well development in the Parshall area sweet spot, which is the cluster of high quality wells on the right hand side of Figure 69. This area is close to full development, with the exception of a few possibilities of in fills. Future drilling must of necessity move out of this sweet spot into areas of generally lower productivity, which will increase the number of wells required to offset field decline going forward.

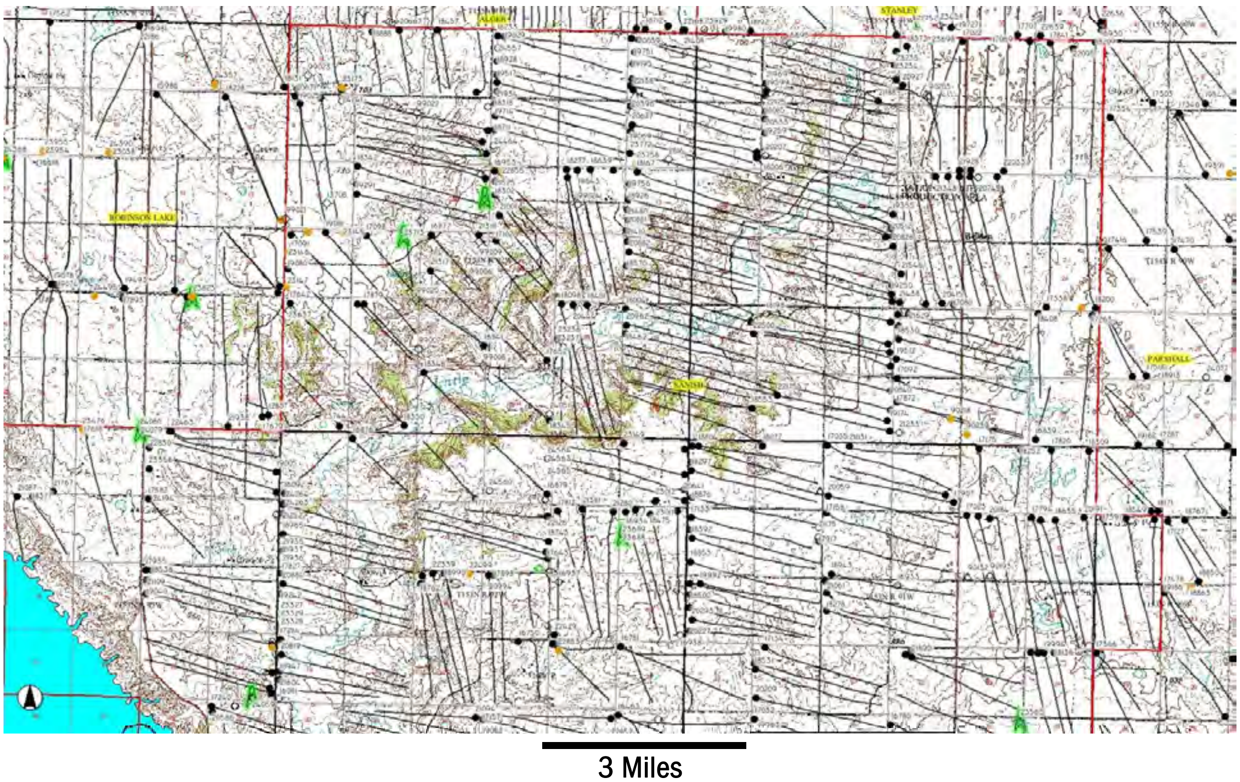

Figure 70. Distribution of horizontal wells in the Parshall "sweet spot" of the Bakken play.[147]

See right-hand side of Figure 69. This area is almost completely saturated with wells although there are still a few locations left. Green symbols indicate rigs drilling as of December 17, 2012.

The Bakken play is a significant new source of oil which is helping to offset declines in conventional fields and grow domestic production somewhat, but is no panacea for long-term United States "energy independence." At 0.5 billion barrels extracted through May 2012, and an estimated ultimate recovery of about three billion barrels by 2025, it can make a total contribution of about six months of United States oil consumption. The production profiles presented in Figure 66 and Figure 67 are likely unrealistic in that drilling is unlikely to proceed at high rates until the last available site is utilized and then stop. A more likely scenario is that production will peak later at a lower level, perhaps at about 850,000 barrels per day as drilling rates slow, and then decline at a more gradual rate with the possibility that declines can be slowed somewhat by re-fracking wells and continuing to add new wells until available locations are used up.

147 Data from North Dakota Department of Mineral Resources Arc IMS viewer current to December 17, 2012, https://www.dmr.nd.gov/OaGIMS/viewer.htm.

Eagle Ford Tight Oil Play

The Eagle Ford of southern Texas is now the second-largest tight oil play in the United States. The application of multi-stage hydraulic fracturing in horizontal wells has allowed production to grow very rapidly. Figure 71 illustrates petroleum liquids production and the number of producing wells since the play's inception in early 2009. Production totaled 524,000 barrels per day from 3,129 operating wells as of June 2012. The Eagle Ford is also a substantial producer of associated gas with production of 2.14 bcf/d in June 2012, making it the fifth-largest shale gas producer in the United States (Table 1). The oil, condensate, and dry gas portions of the Eagle Ford occur in separate but transitional parts of the play.

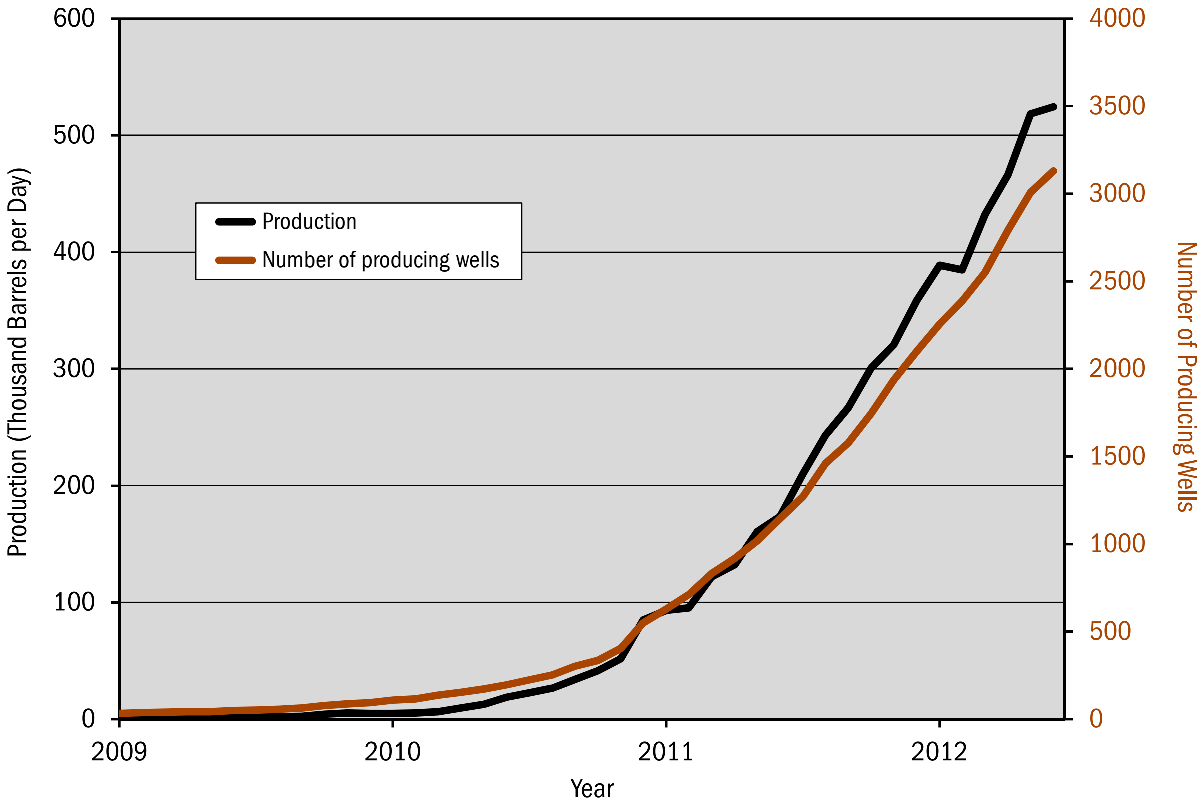

Figure 71. Petroleum liquids production and number of producing wells for the Eagle Ford shale play, 2009 through June 2012.[148]

[148] Data from DI Desktop/HPDI current through May, 2012.

In common with other shale plays, Eagle Ford wells exhibit steep production declines over time. Figure 72 illustrates a type decline curve compiled from 50 months of production data from late 2007 through year-end 2011. Also shown is a curve derived from the first five months of 2012, which indicates that IPs are rising as operators define sweet spots and focus drilling effort on them. The play is so young that the shape of the tail of this curve is uncertain; however, the first-year decline is 60 percent and overall decline in the first two years is 86 percent from average 2011 IP levels and 89 percent from 2012 IP levels. The type curve puts the average Eagle Ford well in the category of a "stripper" well within about three years (less than 15 bbls/d). This is even higher than the decline rate observed in the Bakken play.

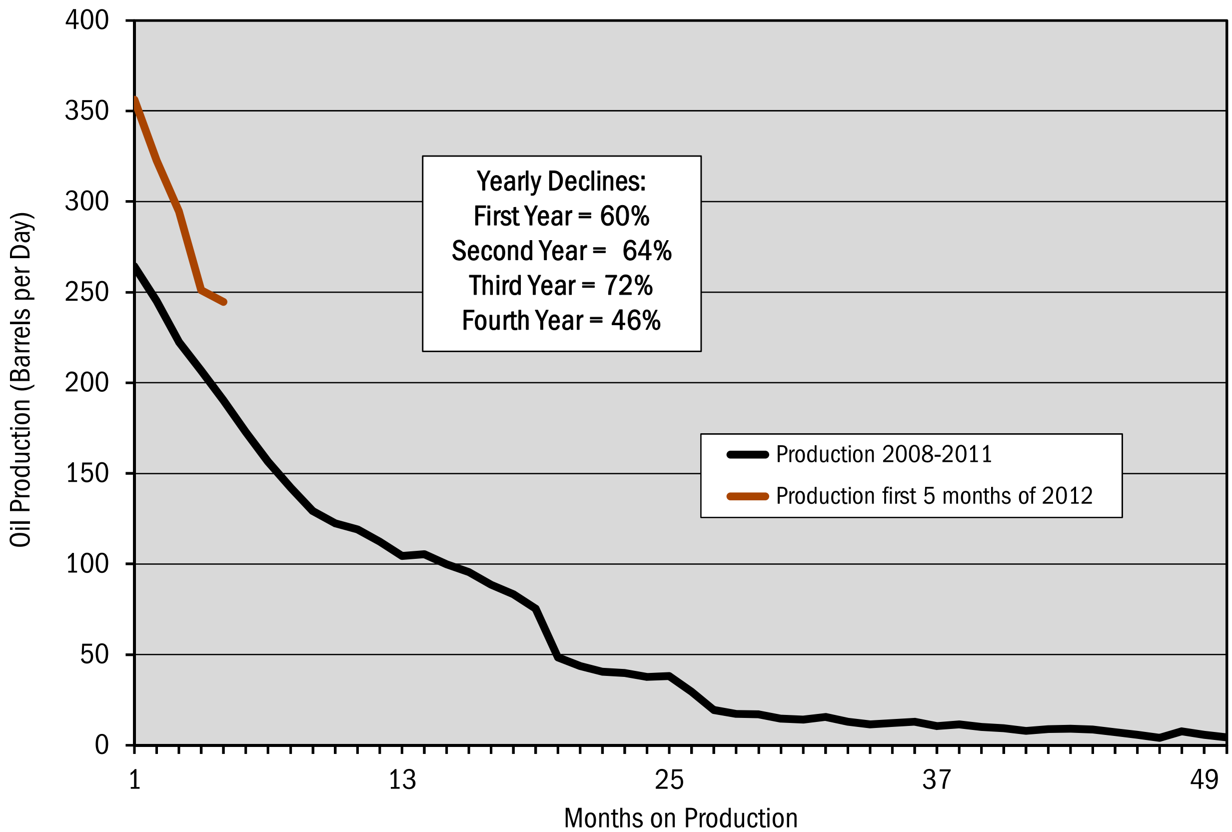

Figure 72. Type decline curve for Eagle Ford liquids production.[149]

Based on data from the most recent 50 months through year-end 2011 of this play's production The production for the first five months of 2012 is also shown, indicating that IP's are rising as drilling focuses on recently defined sweet spots.

The EUR for the Eagle Ford utilized by the EIA to determine an unproved technically recoverable resource estimate of 2.461 billion barrels is 280,000 barrels of oil per well (the EIA also estimates an EUR of 2.36 bcf of shale gas per well)[150]. This is more than five times that of the EUR estimated by the USGS of 55,000 barrels of oil per well (the USGS also estimates an EUR of 1.104 bcf of shale gas per well).[151] A recent paper by Swindell (2012) estimates the average EUR for oil at 115,282 barrels per

[149] Data from DI Desktop/HPDI current through May, 2012.

[150] EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

[151] United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.

well and 1.044 bcf for gas.[152] In contrast, industry estimates of EUR tend to be much higher, such as those of EOG (one of the biggest landholders in the play) at between 430,000 and 460,000,[153]

The initial productivity (IP) of a well when it is first drilled is one measure of well quality and typically bears some correlation to EUR. Figure 73 illustrates the highest one-month production of liquids recorded for wells in the Eagle Ford play. The variability of the wells illustrates the differing geological properties within various parts of the play. The mean IP is 437 bbls/d, with very high quality wells at more than 1,000 bbls/d amounting to about ten percent of the total. The average production of all operating Eagle Ford wells is now 168 bbls/d because of the effect of steep well declines and the fact that overall field production is from a mix of old and new wells. The average liquids production of Eagle Ford wells appears to have flattened out after a sharp rise in 2010 whereas average gas production is declining and is now 558 mcf/d.

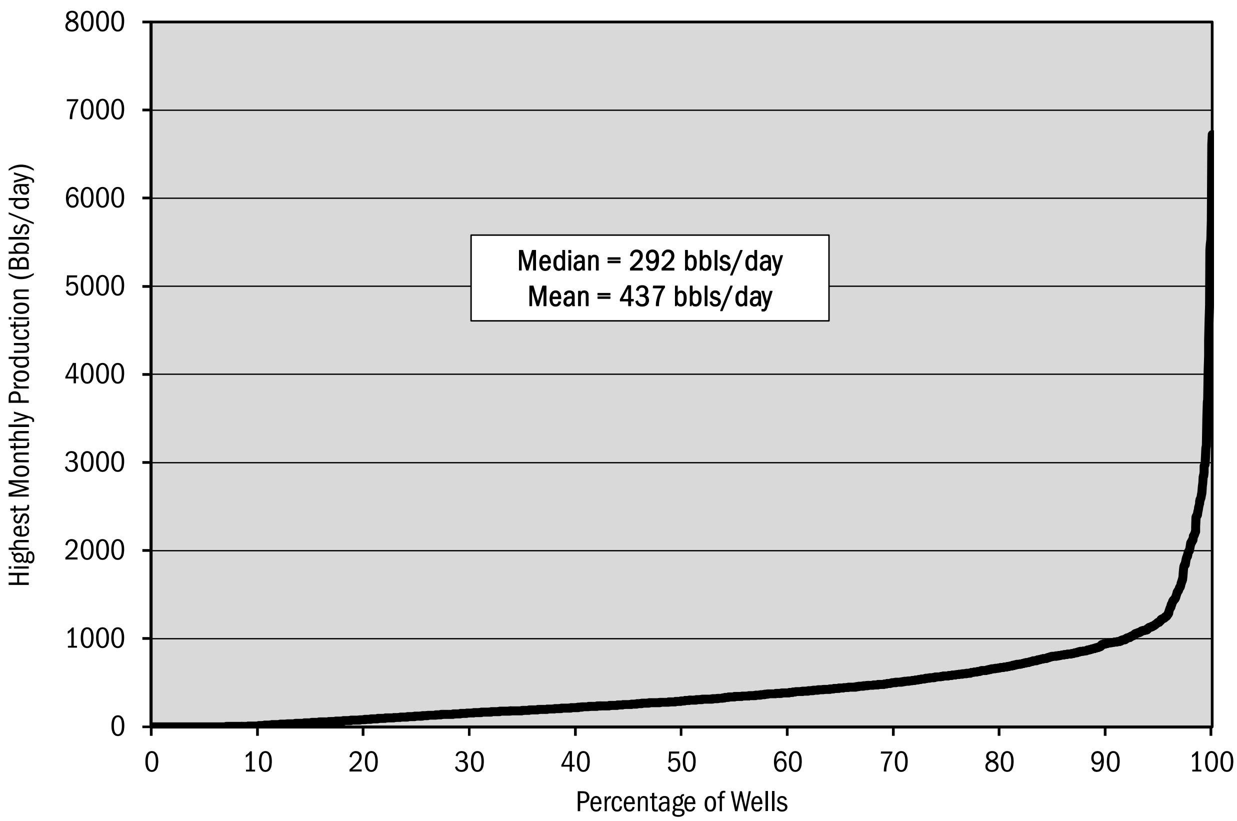

Figure 73. Distribution of well quality in the Eagle Ford play, as defined by the highest one-month rate of production over well life[154].

The highest one-month rate of production is typically achieved in the first or second month after well completion.

[152] Gary S. Swindell, "Eagle Ford Shale – An Early Look at Ultimate Recovery", Society of Petroleum Engineers Paper SPE 158207, 2012, http://gswindell.com/sp158207.pdf

[153] EOG Resources, "EOG Resources South Texas Eagle Ford", 2011, http://www.tidalpetroleum.com/downloads/EOG2011.pdf

[154] Data from DI Desktop/HPDI current through May, 2012.

The overall decline rate of the Eagle Ford play can be estimated from the production from all wells drilled prior to 2011 as illustrated in Figure 74. The yearly overall field decline rate is about 27 percent utilizing existing data; however, this is probably an underestimate as many wells drilled prior to 2011 had not been completed as indicated by the rising well count in 2011 and 2012 in Figure 74. Assuming new wells will produce for their first year at the first-year rates observed for wells drilled in 2011, 723 new wells would be required to offset field decline each year from current production levels. At an average cost of $8 million per well, this would represent a capital input of about $5.8 billion per year, exclusive of leasing and other infrastructure costs, just to keep production flat at today's level. Nineteen hundred and eighty three new wells (1,983) were added in the year prior to June 2012, and the current rig count of 274 is sufficient to maintain this rate of drilling. The youth of this play is indicated by rising IPs in new wells as operators find and target sweet spots and apply longer horizontal laterals and more hydraulic-fracturing stages. Given the type decline curve for oil production from Eagle Ford wells, which is considerably steeper than for the Bakken, the overall field decline is likely at least that of the Bakken—40 percent, and probably steeper.

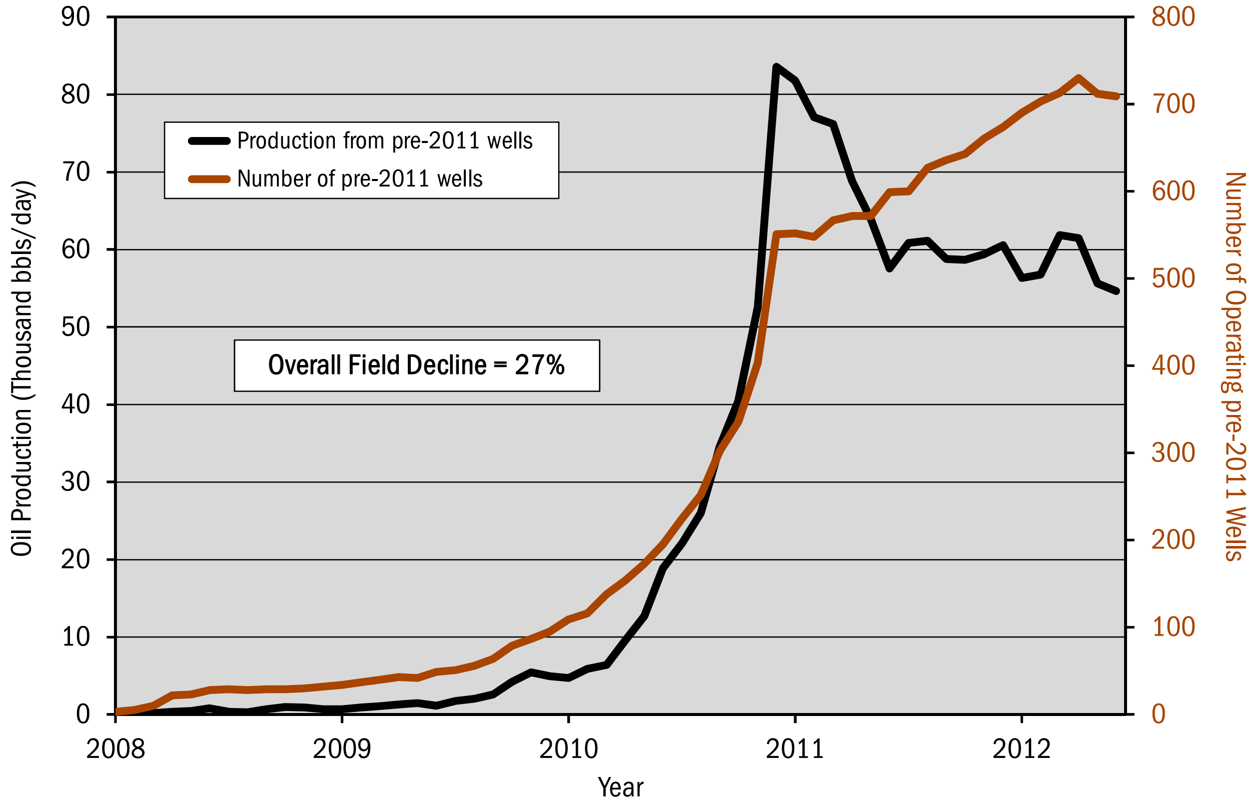

Figure 74. Overall field decline for the Eagle Ford play based on production from wells drilled prior to 2011.[155]

The actual overall field decline is likely steeper than shown as many pre-2011 wells were being connected over the subsequent months as indicated by the rising well count in 2011 and 2012. If the 27 percent rate is accepted, it would require 723 new wells producing at 2011 rates to offset field decline each year from current production levels.

[155] Data from DI Desktop/HPDI current through May, 2012.

The question is, as it was for the Bakken, how much can Eagle Ford production be increased and for how long? Future production growth is dependent on the number of wells drilled annually, new well performance, and the number of locations available to drill. Assuming wells can be added at the current rate of 1,983 per year, and that new well quality remains at current levels (i.e., first-year production in new wells that equals average 2011 first-year levels), the critical parameter governing the production profile of the play becomes the number of available well locations.

The EIA estimates that 8,665 available well locations were left to drill in the liquids-rich window of the Eagle Ford as of January 2010 (and a further 21,285 in the shale gas window).[156] If all existing wells represented the oil window, that would yield—coupled with the 109 wells operating at that time—a total of 8,774 wells when locations run out. This is not the case, however, as at least 30 percent of the wells drilled in the Eagle Ford are in the gas window, hence the effective number of locations with the type curve characteristics in Figure 72 are 30 percent higher at 11,406. Given the steep declines observed in the type curve, the overall field decline is probably at least that of the Bakken at 40 percent, although this is still difficult to estimate given the lack of history in the data.

[156] EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

The future production profile of the Eagle Ford—assuming a total of 11,406 effective locations, a 40 percent overall field decline, and current rates of drilling with all new wells performing as in 2011—is illustrated in Figure 75. This yields a production profile which rises 34 percent from June 2012 levels to a peak of 0.891 million barrels per day in 2016 as illustrated in Figure 75. At this point, with all well locations drilled, production declines at the overall field decline rate of about 40 percent. The overall field decline may decrease somewhat over time after peak as wells approach terminal decline rates. This also assumes that 70 percent of the wells drilled to date have targeted the oil-rich portion of the Eagle Ford play. Total oil recovery in this scenario is about 2.23 billion barrels by 2025, which agrees quite well with the EIA's estimate of 2.46 billion barrels.[157] Average well production falls below 10 bbls/d in this scenario by 2021.

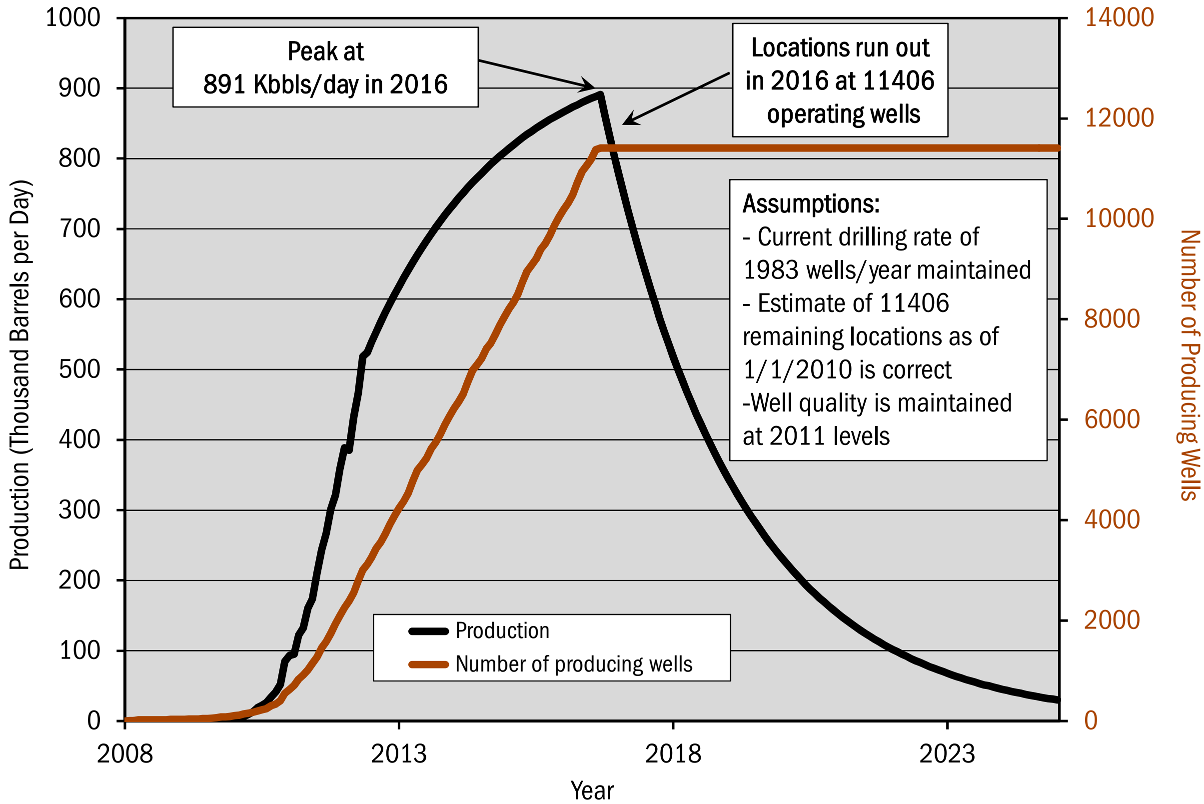

Figure 75. Future liquids production profile for the Eagle Ford play assuming current rate of new well additions.

This scenario assumes constant new well quality and EIA estimate of remaining available well locations. Production declines at the overall field rate of 40 percent after peak in 2016.

[157] EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

The sensitivity to input parameters does not change the overall recovery as long as total well locations are held constant at 11,406 and average well quality does not decline. For example, if drilling rates are increased to 2,500 wells per year the play peaks one year earlier, in 2015, at a higher level production level of 1.031 million barrels per day as illustrated in Figure 76.

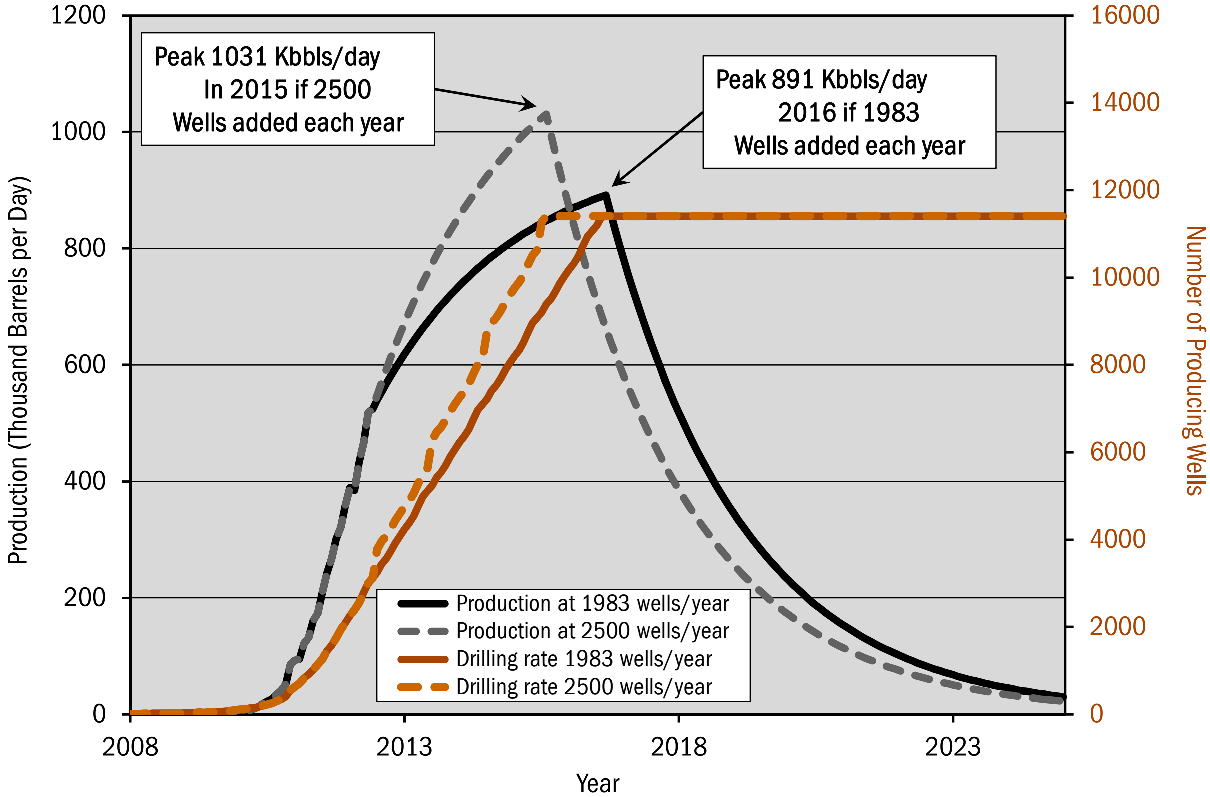

Figure 76. Future oil production profiles for the Eagle Ford play assuming current rate of new well additions compared to a scenario of 2,500 wells per year.

Both scenarios assume constant new well quality at 2011 levels and the EIA estimate of 11,406 total available well locations.[158] Production declines after peak in both scenarios at the overall field rate of 40 percent.

158 EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

An idea of the existing well saturation and the distribution of the highest quality wells in terms of liquids production in the Eagle Ford at this point is illustrated in Figure 77 and Figure 78. EIA estimates of available well locations would see well saturation approximately triple in the oil window and much more overall considering additional locations in the gas window.

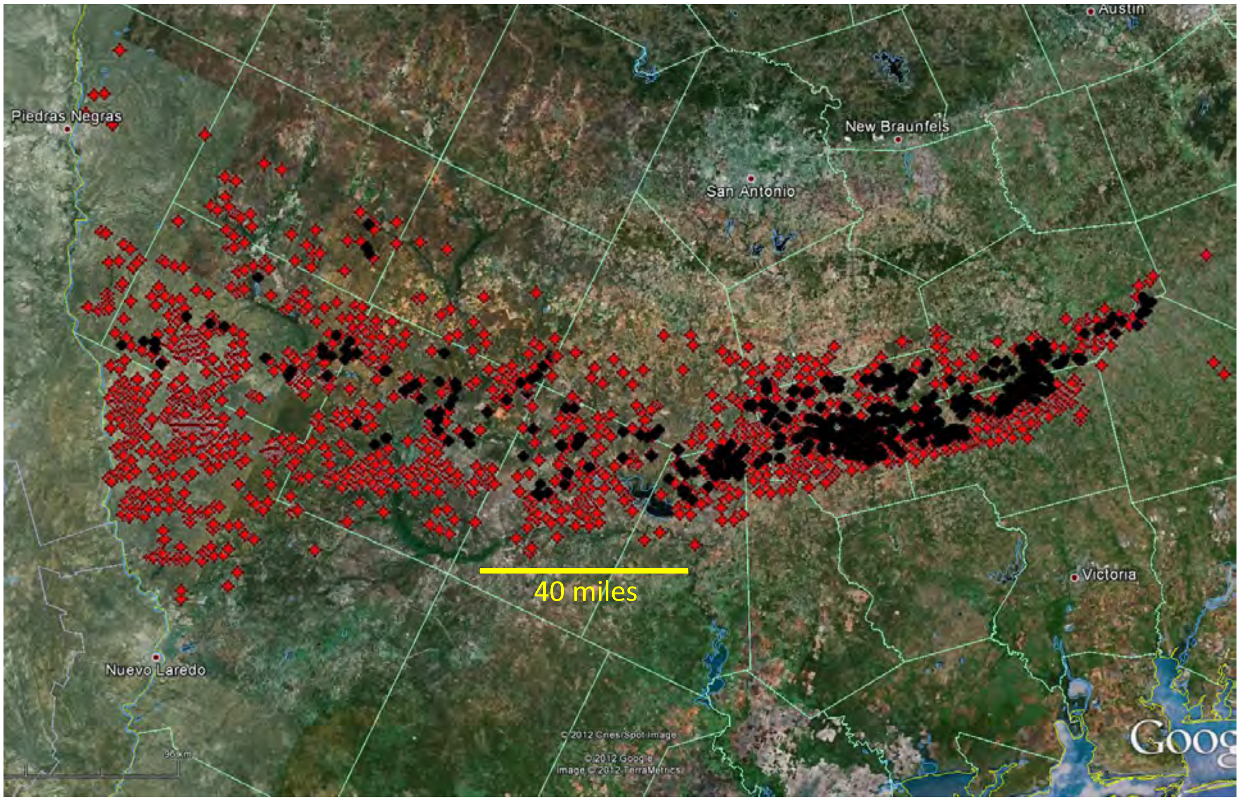

Figure 77. Distribution of wells in the Eagle Ford play.[159]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells. The highest productivity wells tend to be concentrated in in "sweet spots."

[159] Data from DI Desktop/HPDI current through June, 2012.

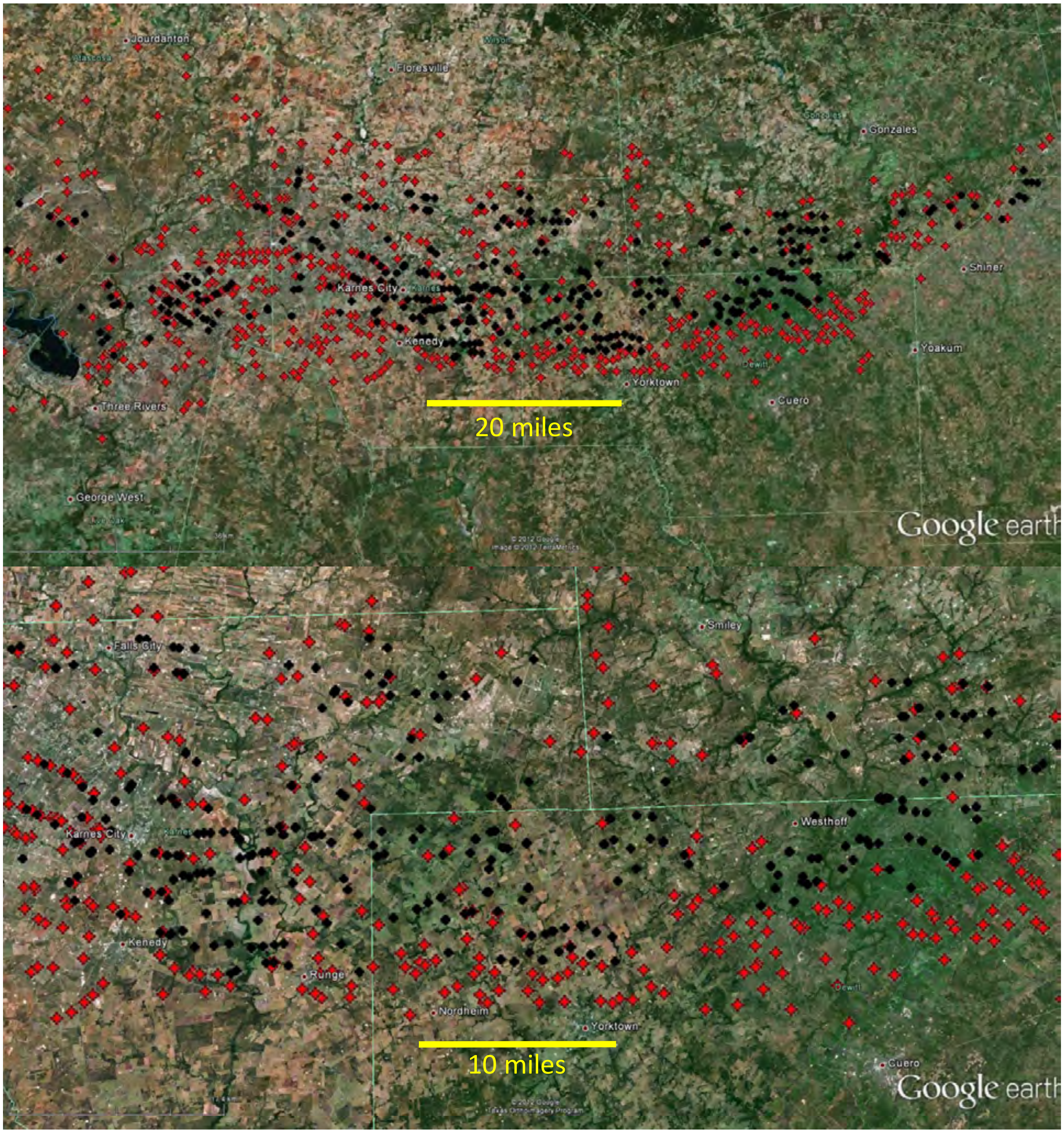

Figure 78. Distribution of wells in the Eagle Ford play's area of highest concentration.[160]

Wells in black are the top 20 percent in terms of initial productivity. Many of these sites are multi-well pads with two or more wells.

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[160] Data from DI Desktop/HPDI current through June, 2012.

The Eagle Ford play is a significant new source of oil which is helping to offset declines in conventional fields and grow domestic production somewhat but, like the Bakken, is no panacea for long-term United States "energy independence". At 0.17 billion barrels extracted through May 2012, and a recovery of up to 2.23 billion barrels by 2025, it can make a total contribution of about five months of U.S. oil consumption. The production profiles presented in Figure 75 and Figure 76 are likely unrealistic in that drilling is unlikely to proceed at high rates until the last available site is utilized and then stop. A more likely scenario is that production will peak later at a lower level, perhaps at about 800,000 barrels per day as drilling rates slow, and then decline at a more gradual rate with the possibility that declines can be slowed somewhat by re-fracking wells and continuing to add new wells until available locations are used up.

Other Tight Oil Plays

Twenty-one tight oil plays were analyzed in all for this report utilizing the parameters for the two plays examined in detail above. A summary of key statistics for all tight oil plays is included in Table 5.

The top two tight oil plays discussed above comprise 80 percent of total shale liquids production. The next three, the Bone Spring, Niobrara, and Granite Wash plays, add a further 11 percent. The remaining 16 tight oil plays contribute only eight percent of production, although some of these plays have been touted as having great promise. Chesapeake Energy's soon-to-be-former CEO Aubrey McClendon, for example, declared the Utica to be "the biggest thing to hit Ohio since the plow." However, the data that would prove that remain shrouded in mystery,[161] and the publically available data included in Table 5 show the Utica to be rather unremarkable.

Tight oil is growing rapidly but the growth is primarily restricted to the two best plays as illustrated in Figure 79: the Eagle Ford and the Bakken. Parameters such as average well production and mean IP (well quality) in Table 5 show how much these fields stand out from the rest, and production from them is projected to continue to grow to a near term peak controlled by available well locations, as has been discussed above. A major question is, what are the prospects for growth for the remaining 19 plays, many of which have hundreds or thousands of wells drilled and demonstrate marginal- to mediocre-performance? Even though many of these wells are older and without the benefit of the latest hydraulic-fracturing technology, indications are that these plays will not come close to the stellar performance of the Bakken and Eagle Ford. This is very important for considerations of longer-term energy security and to put the exuberant forecasts into perspective.

[161] Reuters, "Insight: Is Ohio's 'secret' energy boom going bust?", October 22, 2012, http://www.reuters.com/article/2012/10/22/us-ohio-shale-idUSBRE89L04H20121022.

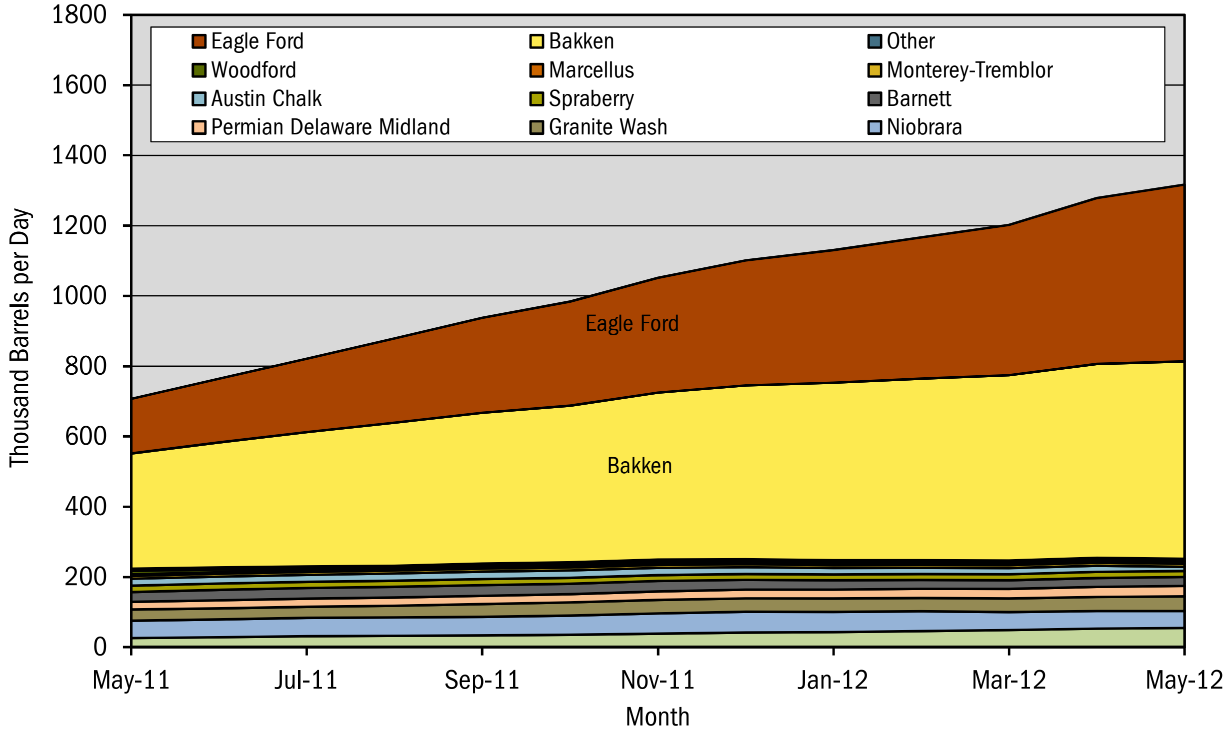

Figure 79. Tight oil production by play, May 2011 through May 2012.[162]

The Bakken and Eagle Ford are clearly unique among tight oil plays in the United States. (See Figure 60 for production since 2000.)

162 Data from DI Desktop/HPDI current through May, 2012, fitted with three month moving average.

Field	Rank	Production (Kbbls/d)	Month	Number of Operating Wells	Average Well Production (bbls/d)	Mean IP (bbls/d)	Median IP (bbls/d)	IP Trend	First year well decline (%)	Overall annual field decline pre-2011 (%)	Number of Wells needed annually to offset decline	Production Trend	Percent of Total Tight oil Production
Bakken	1	569.00	May-12	4598	124	400	341	Flat	69	40	819	Rising	41.95
Eagle Ford	2	524.23	Jun-12	3129	168	437	292	Rising	60	27-40+	723	Rising	38.64
Bone Spring	3	56.42	May-12	1016	56	173	113	Rising	74	45	211	Rising	4.16
Niobrara	4	51.00	May-12	10811	4.7	25.2	17.2	Flat	79	51	1139	Flat	3.76
Granite Wash	5	41.26	Jun-12	3090	13.4	73	26	Rising	71	58	267	Rising	3.04
Permian Del. Midland	6	30.00	Jun-12	1541	19.5	83.2	44.2	Rising	66	30	99	Rising	2.21
Barnett	7	26.65	May-12	14871	1.79	14	0	Rising	65	58	1306	Flat	1.96
Austin Chalk	8	17.20	Jun-12	928	18.5	193	79	Declining	72	34	73	Declining	1.27
Spraberry	9	17.13	Jul-12	552	31	154	68	Rising	19	19	84	Flat	1.26
Monterey-Tremblor	10	8.58	Jun-12	675	12.7	37.9	27.9	Declining	18	9	48	Flat	0.63
Marcellus	11	5.26	Dec-11	3848	1.85	3.4	0	Flat	34	39	970	Rising	0.39
Woodford	12	3.95	May-12	1827	2.2	14.4	0	Declining	69	74	410	Declining	0.29
Miss. Lime	13	2.260	Apr-12	371	6.1	28.9	10.5	Declining	52	30	52	Declining	0.17
Tuscaloosa	14	1.48	May-12	23	64.5	121	22.3	*	*	*	*	Rising	0.11
Mancos Hilliard Baxter	15	0.80	May-12	452	1.78	6.9	1.6	Flat	57	31	45	Rising	0.06
Pierre	16	0.750	Apr-12	193	3.9	17.1	0	*	*	*	*	Flat	0.06
Mowry	17	0.2230	Jun-12	39	5.7	28	10	*	*	*	*	Flat	0.02
Manning	18	0.107	May-12	45	2.4	17.3	11.4	*	*	*	*	Flat	0.01
Utica	19	0.104	Dec-11	13	8	13	2.6	*	*	*	*	Rising	0.01
Mulky	20	0.069	May-12	120	0.58	0.69	0	*	*	*	*	Flat	0.01
Cody	21	0.05	Jun-12	11	5	8	5	*	*	*	*	Flat	0.00

Table 5. Tight oil play key statistics on production, well quality and decline rates for the 21 tight oil plays analyzed in this report.[163]

[163] Compiled from an analysis of DI Desktop/HPDI data.

Analysis

Although the high production rates of the Bakken and Eagle Ford tight oil plays are very new, many of the other plays have been producing for many years. The evolution of the Bakken and Eagle Ford was similar to that observed with shale gas:

- The play is identified and a leasing frenzy follows. In the case of the Bakken, the largest early entrant was Continental Resources Inc., which has produced the most bullish estimates for available drilling locations and recoverable resources.
- Drilling to hold leases is conducted at a similarly frenzied pace, which also serves to define "sweet spots" (the highest quality portions of a play) and the extents of the play. This imposes a new way of life on local residents as workers pour in and strain local infrastructure and resources.[164]
- Production rises rapidly and drilling shifts to focus on the sweet spots. This is evidenced by rising IPs, which is pronounced in the early life of all shale plays. The Eagle Ford is in this phase as attention is focused on oil and liquids-rich portions of the play, and oil IPs are growing.
- Application of "better" technology, such as longer horizontal laterals with more hydraulic-fracturing stages, serves to maintain IPs even as drilling moves away from sweet spots to lower quality parts of a play. The Bakken is in this later phase of development as IPs are flat and will soon begin to decline as sweet spots become saturated with wells.
- Eventually better technology cannot make up for lesser-quality geology, and IPs of new wells decline.
- As IPs decrease, more wells are required to offset overall field declines, and without massive amounts of new drilling the plays go into terminal decline. In the case of the Bakken and Eagle Ford, production is ultimately limited by available drilling locations. Production is likely to follow a bubble trajectory with a lifespan of less than ten years at current or higher production levels.

[164] Josh Harkinson, "Who Fracked Mitt Romney", Mother Jones, November/December 2012, http://www.motherjones.com/environment/2012/10/harold-hamm-continental-resources-bakken-mitt-romney.

The Bakken and Eagle Ford plays are in early middle-age and youth phases of the tight oil lifecycle, respectively. The prognosis for the top ten tight oil plays in the United States, which account for 99 percent of tight oil production, is presented in Table 6.

Field	Rank	Number of Wells needed annually to offset decline	Wells Added for most recent Year	October 2012 Rig Count	Prognosis
Bakken	1	819	1500	186	Rising
Eagle Ford	2	723	1983	274	Rising
Bone Spring	3	211	300	N/A	Rising
Niobrara	4	1139	1178	~60	Flat
Granite Wash	5	267	205	N/A	Rising
Permian Delaware Midland	6	99	94	N/A	Rising
Barnett	7	1306	1112	42	Flat
Austin Chalk	8	73	25	N/A	Declining
Spraberry	9	84	66	N/A	Flat
Monterey-Tremblor	10	48	53	N/A	Flat

Table 6. Prognosis for future production in the top ten tight oil plays in the United States.

These plays constitute 99 percent of tight oil production.

Notwithstanding the fact that there will certainly be some growth in tight oil production in plays like the Bone Spring, Granite Wash, and Permian, these plays are dwarfed by the growing production in Bakken and Eagle Ford. As noted earlier, however, the ultimate production of the Bakken and Eagle Ford is limited by available drilling locations and, depending on the rate of addition of new wells, is likely to peak in the 2015-2017 timeframe. Figure 80 illustrates a projection of tight oil production in the United States from the 21 plays studied assuming current drilling rates are maintained until locations run out. Tight oil production peaks in 2016 in this scenario.

It is assumed in this projection that growth at recent rates can be maintained in the "other" play category, which contains 19 plays that account for less than 20 percent of current tight oil production. This growth is by no means certain, however, as most of these plays have relatively low production rates by comparison to the Bakken and Eagle Ford and therefore have less attractive economics. The peak at over two million barrels per day is significant in terms of short term domestic supply, but the following decline has been totally ignored in the exuberant forecasts touted by those projecting "energy independence." This projection calls for slightly lower growth than in the EIA forecasts of Figure 30, and much faster falloff – total tight oil recovery by 2025 would be 7.3 billion barrels.

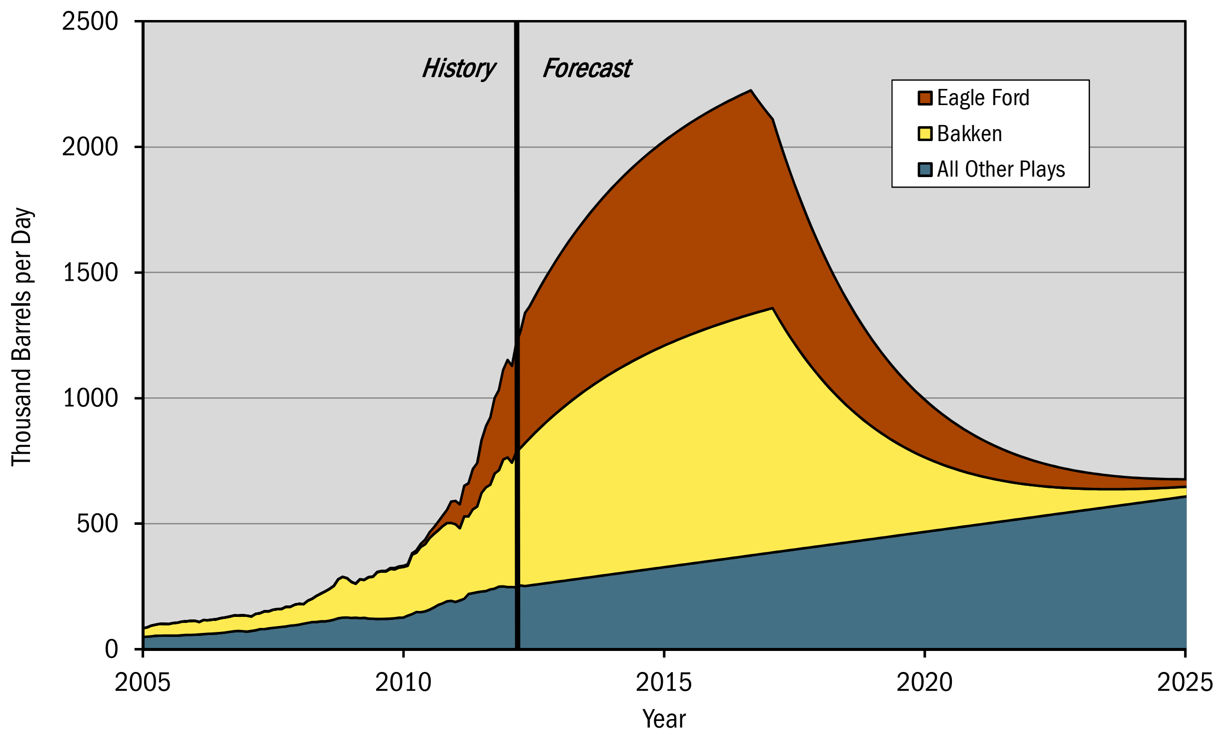

Figure 80. Projection of tight oil production by play in the U.S. through 2025.

Based on vintaged type curve production, the number of drilling locations projected by the EIA for the Bakken and Eagle Ford plays, and the assumption of continued recent growth rates in the other plays.

The Eagle Ford play is in its youth, and production of tight oil will grow substantially. Oil IPs are rising as drilling is focused on the oil window and moving away from the gas window. It is only a matter of time, however, until available locations in the oil window become saturated and the Eagle Ford moves into middle age. This is the stage in shale play evolution that the Bakken is now entering, although it still has significant growth potential ahead.

Similarly, growth in shale gas production in the Eagle Ford and Bakken plays is strong (gas is produced in association with oil, which is the main target). IPs for gas are declining in the Eagle Ford, however, as operators focus on oil production. Much of the gas produced in the Bakken is flared as there is a lack of infrastructure to utilize it.

The approximate investment in drilling required to maintain current production levels in the top 14 tight oil plays, which account for over 99 percent of production, is $35.8 billion annually (Table 7). This does not include leasing costs or the costs of other infrastructure such as pipelines and roads, etc. This cost, and the number of new wells required annually, will increase going forward as the sweet spots are exhausted and drilling moves into lower-quality areas.

Field	Rank	Number of Wells needed annually to offset decline	Approximate Well Cost (million US$)	Annual Well Cost to Offset Decline (million $US)
Bakken	1	819	10.0	$ 8,190
Eagle Ford	2	723	8.0	5,785
Bone Spring	3	211	4.0	844
Niobrara	4	1139	4.0	4,556
Granite Wash	5	267	6.0	1,602
Permian Delaware Midland	6	99	6.9	683
Barnett	7	1306	3.5	4,571
Austin Chalk	8	73	7.0	511
Spraberry	9	84	6.9	580
Monterey-Tremblor	10	48	~3.0	144
Marcellus	11	970	5.0	4,850
Woodford	12	410	8.0	3,280
Mississippi Lime	13	52	~4.0	208
Total		**6201**		**$ 35,804**

Table 7. Estimated annual drilling costs to maintain tight oil production in the top 13 plays.

The number of wells and the capital costs to offset declines in tight oil and shale gas wells are not additive as some of the wells produce both. It is estimated that declines in all tight oil and shale gas plays studied would require about 8,600 wells each year at a cost of $48.2 billion annually to maintain production.

The number of wells required to offset declines further exemplifies the high productivity of the top two tight oil plays compared to all the rest. Fifteen hundred and forty two (1,542) wells at a cost of $14 billion can offset declines in 80 percent of U.S. tight oil production, whereas 4,659 wells at a cost of $21.8 billion are required to offset declines in the remaining 20 percent. Yet there is a great deal of industry hype about the prospects of some of the 19 tight oil plays that currently constitute less than 20 percent of tight oil production. Considering the attributes of most of these plays documented in Table 5, such claims appear to be merely hype. Like shale gas plays, the best tight oil plays are not ubiquitous—

they are at the top of their own pyramid as illustrated in Figure 37, with many lesser-quality plays below them. Their *rate of supply* is dependent on very large and continuous inputs of capital for drilling, along with progressively escalating collateral environmental impacts.

Tight oil unproved technically recoverable resources have been revised upwards slightly for 2010 by the EIA from 31.5 to 33.2 billion barrels.[165] Notwithstanding the fact that *rate of supply* is a more critical parameter than purported resource estimates, 33.2 billion barrels represents just four years of U.S. supply at 2011 consumption rates Nevertheless, tight oil continues to be heralded as the main underpinning of U.S. "energy independence" rhetoric.

The EIA goes on to estimate the level of effort that will be required to recover the unproved technically recoverable tight oil resource in terms of the number of available well locations left to drill along with estimated mean EURs as illustrated in Table 8.[166] The EIA estimates that 219,730 wells will be required to recover the estimated 33.2 billion barrels of tight oil. As with shale gas, the law of diminishing returns is well illustrated in this table. Seventy-one percent of the resource, or 23.7 billion barrels, require just 29 percent of the wells to recover. The remaining 29 percent of the resource requires 71 percent of the wells.

Furthermore, 41 percent of the purported tight oil resource is contained in the Monterey play of California. That this much oil can be recovered from the Monterey is highly questionable. Recent drilling results have been disappointing[167] and the longer-term performance of the Monterey is mostly at "stripper well" levels (Table 5), with an average of 12.7 barrels per day from 675 wells. This bears no comparison to the Bakken or Eagle Ford despite the early enthusiasm.

Moreover, if USGS mean estimates are incorporated (Table 8), the range of technically recoverable unproved resources is from 23 to 34.6 billion barrels (assuming in both cases that 13.7 billion barrels is recoverable from the Monterey). Although significant, this is hardly cause for celebrating U.S. "energy independence", as it represents somewhere between three and four years of consumption, even if it all could be recovered—which would take decades.

There have been no definitive studies on the net energy (EROEI) of tight oil and it is certain to be highly variable depending on the productivity of the play. However it is likely to be lower on average than for conventional oil given the nature of the hydraulic-fracturing process, which involves handling and disposing of millions of gallons of water, several hundred heavy truck trips per well, very high pressures for fluid injection, and so forth.

[165] EIA, 2012, Annual Energy Outlook 2012, page 57, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[166] EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.
[167] Associated Press, "Analyst: Calif. Shale oil field disappoints", July 31, 2012, http://www.businessweek.com/ap/2012-07-31/analyst-calif-dot-shale-oil-field-results-disappoint.

The highest-productivity wells of the Bakken and Eagle Ford are probably quite high in EROEI. The mean and median wells, however, are much lower. On a monetary basis, the concept (as suggested by the EIA in Table 8 for example) that the industry would drill 127,451 wells in the Niobrara to recover an average lifetime production of 55,000 barrels per well at an average well cost of four million dollars is unlikely. By current economics such an undertaking would be extremely marginal, as well costs are only part of total expenses (unless significant amounts of natural gas can also be recovered to bolster economics). Although the EROEI of such wells is likely very low, they comprise more than half of the wells the EIA suggests will be required to recover tight oil resources.

Field	EIA Number of Potential Wells (as of 1/1/2010)	EIA Mean EUR per Well (million barrels per well)	EIA TRR (billion barrels)	USGS Mean EUR (million barrels per well)	TRR using USGS EUR or USGS published estimates (billion barrels)	Minimum TRR (billion barrels)	Maximum TRR (billion barrels)
Bakken	9767	0.55	5.37	.064-.241	3.645	3.65	5.37
Eagle Ford	8665	0.28	2.46	0.055	0.835	0.84	2.46
Bone Spring	4085	0.39	1.59	-	-	1.59	1.59
Niobrara	127451	0.055	6.50	.011-126	0.227	0.23	6.50
Austin Chalk	21165	0.13	2.69	0.055	1.164	1.16	2.69
Spraberry	4638	0.11	0.51	0.057	0.264	0.51	0.26
Monterey-Tremblor	27584	0.5	13.71	-	-	13.71	13.71
Woodford	16375	0.02	0.39	0.064	1.048	0.39	1.05
Utica	-	-	-	0.034	0.94	0.94	0.94
Total	219730		33.23			23.02	34.58

Table 8. U.S. tight oil potential wells and resources, EIA estimates versus USGS estimates.

This table shows EIA estimates of potential wells in various tight oil plays, as well as EIA estimates of tight oil unproved technically recoverable resources (TRR)[168] compared to USGS estimates from published sources[169] or calculated from published USGS estimates of maximum EUR.[170] The minimum and maximum estimates reflect a compilation of estimates from both sources.

Environmental Considerations

The environmental issues surrounding tight oil are similar to those reviewed above for shale gas. A review of some of the issues such as the associated social problems with the oil boom in the Bakken, and oil spills which are unique to tight oil plays, is provided by Harkinson.[171]

[168] EIA, 2012, Annual Energy Outlook 2012, page 58, http://www.eia.gov/forecasts/aeo/pdf/0383(2012).pdf.

[169] Mean USGS estimates for the Utica shale are from http://energy.usgs.gov/Miscellaneous/Articles/tabid/98/ID/200/Assessment-of-undiscovered-oil-and-gas-resources-of-the-Ordovician-Utica-Shale-of-the-Appalachian-Basin-Province-2012.aspx and for the Woodford-Anadarko, Eagle Ford and Niobrara are from page 15, http://pubs.usgs.gov/of/2011/1242/.

[170] United States Geological Survey, "Variability of Distributions of Well-Scale Estimated Ultimate Recovery for Continuous (Unconventional) Oil and Gas Resources in the United States," 2012, http://pubs.usgs.gov/of/2012/1118/.

[171] Josh Harkinson, "Who Fracked Mitt Romney?", Mother Jones, November/December, 2012.

OTHER UNCONVENTIONAL OIL

KEY TAKEAWAYS

- **Oil Shale:** The IEA in its latest World Energy Outlook has listed a trillion barrels of oil shale as "technically recoverable" in the Americas. Despite many years and large expenditures, oil shale has not been produced in commercial quantities in the U.S., and has only been utilized in minor quantities elsewhere in the world. Oil shale production remains an extreme example of a rate- and net-energy-constrained resource. There is no significant production now nor is there likely to be in the foreseeable future.
- **Deepwater oil** is a stable part of U.S. oil supply and is projected to make up about ten percent of overall U.S. consumption for the next two decades and longer. Opening up coastal areas currently under moratoriums would expand access to relatively minor additional resources, and Arctic offshore oil production is unlikely to be more than a niche supply for the foreseeable future.
- **Extra-heavy oil** (Venezuela) is rate-constrained, due to above-ground geopolitical issues, as well as the capital input and infrastructure required to meet the challenges in its production. It is also a low net-energy oil somewhat similar to tar sands. Notwithstanding that Venezuela has recently claimed first place in world oil "reserves", its extra heavy oil is unlikely to provide significant new production to offset declines in world conventional crude oil production in the short- and medium-term.
- **Biofuels**, which contribute about five percent of U.S. consumption, are projected by the EIA to have little growth over the next two decades or more. Agricultural subsidies for corn ethanol production ended in the U.S. in 2011 although State and Federal renewable fuel standards will ensure ample demand for corn ethanol going forward. The net energy of biofuels is generally very low and there is considerable controversy in utilizing food crops for their production. Production from non-food cellulosic- and algae-feedstocks will play a niche role going forward but is not expected to have a significant impact for at least the next two decades.
- **Coal- and Gas-to-liquids** are expected to grow to perhaps two percent of world liquids supply by 2035. The infrastructure required is high cost and the case of coal comes with heavy GHG emissions and energy conversion loses.
- **Enhanced Oil Recovery** – CO_2 injection to recover residual oil in depleted reservoirs has been utilized for decades, although rarely with anthropogenic CO_2 emissions. Even with a projected doubling in production by 2040 it will still meet less than 4 percent of U.S. demand.

Tar Sands

KEY TAKEAWAYS

- Canada is the United States' largest source for oil imports, accounting for 24 percent of gross U.S. oil imports in 2011. More than half of Canadian production comes from the tar sands.
- Tar sands provide high-cost, low-net-energy oil. Surface mineable resources have the highest net energy, at about 5:1 with upgrading. New surface mineable projects require over $100/bbl to justify development. Eighty percent of recoverable resources are too deep for surface mining, and require very large inputs of energy to recover, which results in a net energy return of less than 3:1 with upgrading.
- The tar sands are being high-graded. Nearly 90 percent of the 25.6 billion barrels "under active development" are shallow surface mineable resources. More than 90 percent of the 143 billion barrels of resources "not under active development" are too deep for surface mining and are extractable only using *in situ* methods.
- The 1.84 trillion barrel *in situ* estimate for the tar sands is irrelevant in considering future supply. Even the purported 143 billion barrels "not under active development" estimated by the Alberta Government to be "recoverable" has no detailed engineering studies validating it.
- Growth forecasts for the tar sands tend to be very aggressive, and have historically always overestimated actual production. It has taken 40 years to grow tar sands production to 1.6 mbd, yet forecasts call for nearly tripling current production over the next 18 years. This will be very difficult and likely impossible to achieve given the logistical bottlenecks and cost inflation experienced even expanding production to current levels (projections assume nearly double the expansion rate that caused earlier problems).
- Tar sands oil comes with higher environmental impacts than conventional oil through air emissions on site, full-cycle well-to-wheels CO_2 emissions, and groundwater and other contaminants.

Resources

Canada possesses the largest resources of tar sands (or "natural bitumen") in the world. Canada is also the United States' largest source for oil imports, accounting for 24 percent of gross U.S. oil imports in 2011. Since more than half of Canadian production now comes from the tar sands, the future of tar sands production is of particular importance to U.S. energy imports. .

Production of conventional light, medium, and heavy oil has long been in decline in Canada and this trend is projected to continue. The major production growth area is tar sands, which is now more than half of Canadian production as illustrated in Figure 81. Also shown in Figure 81 is Canada's consumption of oil, which is currently just under two million barrels per day and rising. While Canada is a significant net exporter of oil to the U.S. it is also a significant importer, as most of Eastern Canada is dependent on offshore imports of about 0.8 million barrels per day.

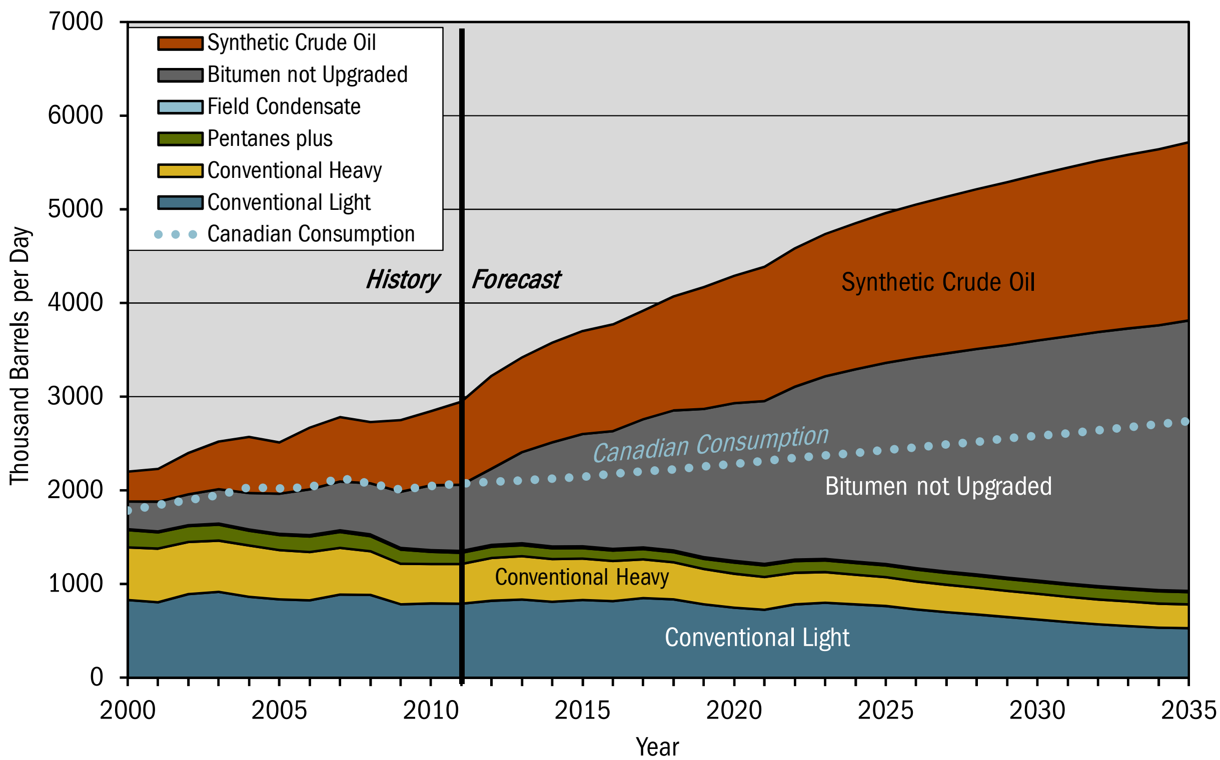

Figure 81. Canadian oil production and consumption, history, and forecasts, 2000-2035 (NEB, 2011).[172]

[172] National Energy Board, "Canada's Energy Futures Appendix", 2011, Tables 2-01 (reference case consumption) and 3-31 (reference case production), A 14% volume loss is assumed in converting bitumen to synthetic crude oil, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035ppndc-eng.zip.

Although tar sands are widely distributed in Northern Alberta (Figure 82), more than half of the in situ resource—and the only portion shallow enough to be surface mineable—is contained in the Wabiskaw-McMurray Deposit.

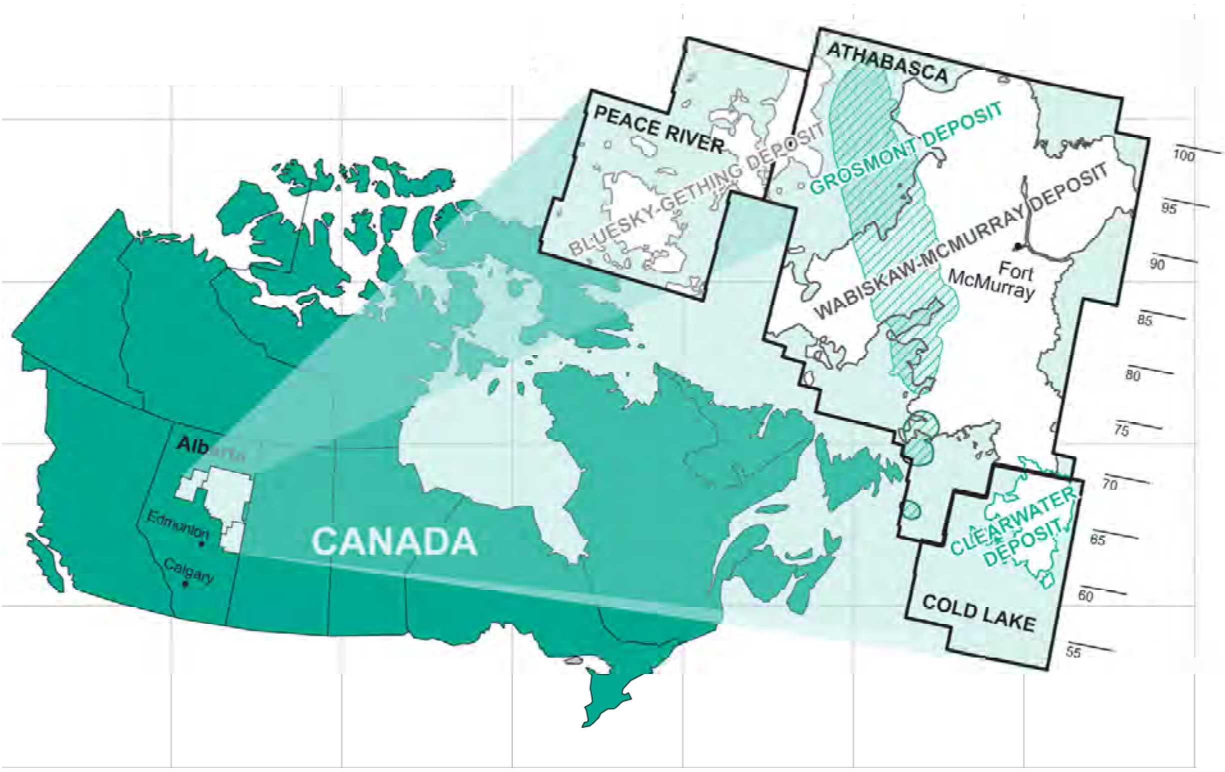

Figure 82. Distribution of Alberta tar sands deposits.[173]

[173] Alberta Energy Resources Conservation Board, Report ST98-2011, 2011, Figure R3.1, http://www.ercb.ca/data-and-publications/statistical-reports/st98.

As with all hydrocarbon deposits, the quality of tar sands resources is diverse. Eighty percent of the purported resources are too deep to be surface mineable, recoverable only by in situ methods, and there is a wide range of reservoir quality in both the surface mineable and in situ recovery areas. Figure 83 illustrates the distribution of bitumen by pay thickness in the surface mineable area (SMA) and in situ portions of the most important deposit, the Wabiskaw-McMurray.

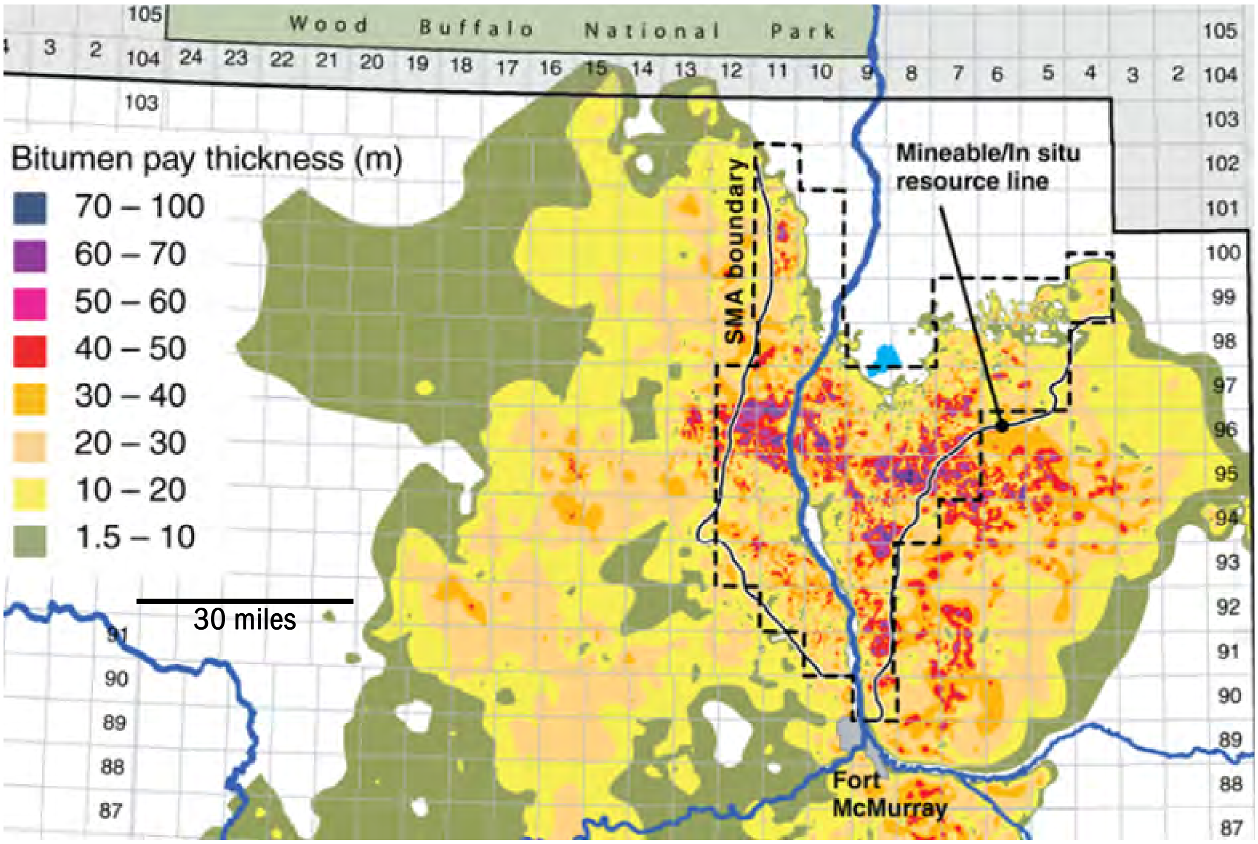

Figure 83. Distribution of bitumen pay thickness in the Wabiskaw-McMurray Deposit.[174]

Bitumen pay thickness is a proxy for resource quality. The cutoff line separating surface mineable deposits (SMA) and in situ deposits is indicated. As can be seen, the thickest pay is located in the surface mineable area and is relatively localized.

Reserves of bitumen up until 2003 were cited as the amount "under active development" by sources such as the BP Statistical Review of World Energy and the Oil and Gas Journal. These amounted to about 26 billion barrels. In 2003 the Oil and Gas Journal upped its "reserve" estimate of bitumen to 174 billion barrels. BP resisted including this larger number in its main world estimates until 2012. It is questionable if the 174 billion barrel estimate has undergone the engineering analysis required to be truly called a reserve in the legal sense of the word. However, neither BP nor the Oil and Gas Journal nor the Alberta Energy Resource Conservation Board (ERCB) have any liability in a Court of Law in terms of what they call a reserve in their publications, so one must take this number with a grain of salt.

[174] Alberta Energy Resources Conservation Board, Report ST98-2010, 2010, Figure 2.3, http://www.ercb.ca/data-and-publications/statistical-reports/st98.

Production and Forecasts

One thing that is clear is that the tar sands are being high-graded, with the best and most profitable resources extracted first (Table 9). Although the in situ resource is said to be over 1.8 trillion barrels, less than ten percent is purported to be an "established reserve". Of this only 15 percent is "under active development." Surface-mineable bitumen requires the least input of energy to recover and comprises 64 percent of the 8.1 billion barrels recovered so far. Of the remaining reserves "under active development," 88 percent are surface mineable. Of what remains of the "established reserves" not under active development, just eight percent are surface mineable with the balance recoverable only by more energy intensive in situ methods.

Recovery Method	In Situ Resource	Remaining Established Reserves	Cumulative Production	Remaining Established Reserves Under Active Development	Remaining Established Reserves NOT Under Active Development
Surface Mineable	130.9	33.6	5.16	22.6	11.0
In Situ	1713.6	135.0	2.96	3.0	132.0
Total	**1844.4**	**168.6**	**8.12**	**25.6**	**143.0**

Table 9. Alberta tar sands reserves and resources estimates, by recovery method (ERCB, 2012).[175]

All numbers are in billion barrels.

The question of course becomes, what is the future outlook for production from the tar sands? The Canadian Association of Petroleum Producers (CAPP), an industry lobby group, produces forecasts of production and supply each year, the latest of which is illustrated in Figure 84. They produce an "in construction" forecast, which is the projection of production from all existing operations and projects under construction, as well as a production "growth" forecast. They also produce a "supply" forecast for the growth scenario. The difference between the production growth and supply forecasts reflects the need for imported diluents. This is due to the fact that bitumen needs to be diluted with about 30 percent gas condensate or 50 percent synthetic crude oil (creating diluted bitumen, or "dilbit") in order to move it through a pipeline. Ironically, given that Canadian politicians tout the energy superpower rhetoric, Canada would have to import 700,000 barrels of diluents per day by 2030 to meet the CAPP growth forecast (Figure 84). As can be seen from Figure 81, the production and sale of raw bitumen is expected to grow much faster than production of synthetic crude oil owing to the expense (and general lack of economic justification) of upgraders.

[175] Alberta Energy Resources Conservation Board, Report ST-98-2012, 2012, Table 3.1, http://www.ercb.ca/data-and-publications/statistical-reports/st98

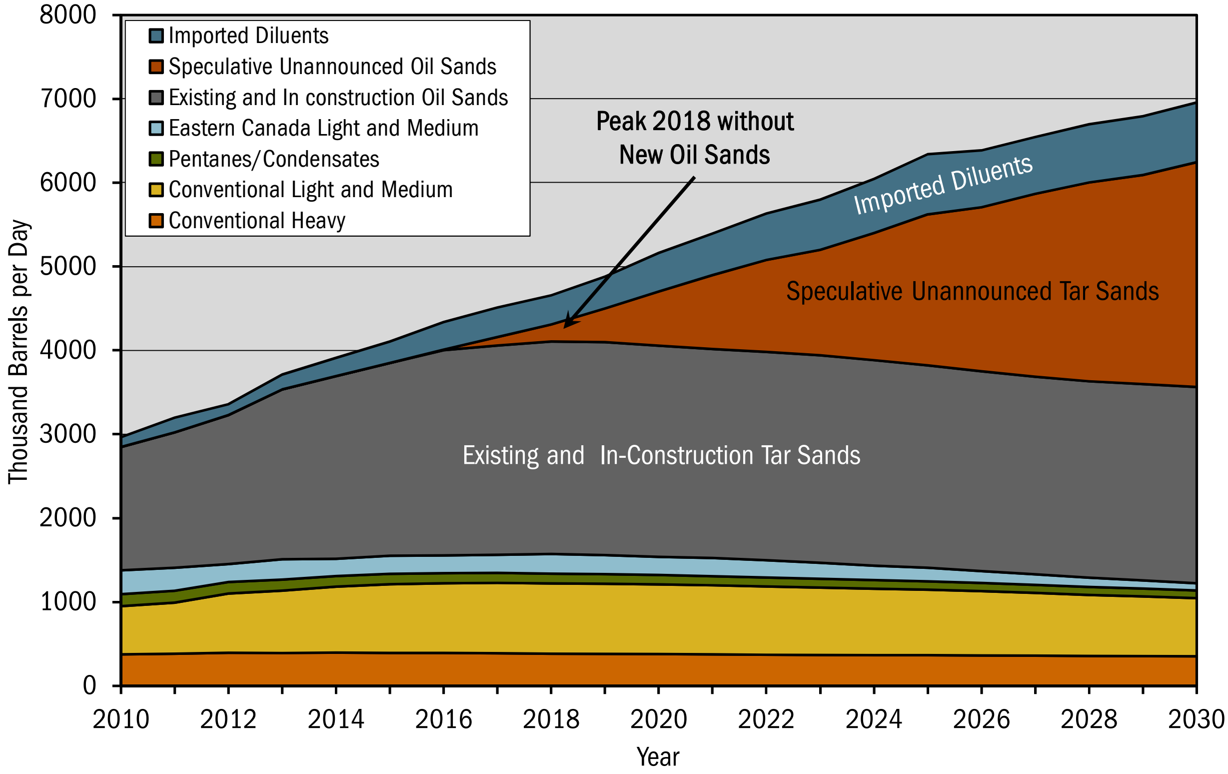

Figure 84. Canadian oil production and supply forecasts, 2010-2030 (CAPP, 2012).[176]
Total supply is the sum of production and imported diluents.

The need to export 30 to 50 percent more volume in the form of diluents to move dilbit, instead of synthetic crude oil, is behind the drive to build additional pipeline capacity from Canada via the Enbridge Northern Gateway proposal, the Kinder-Morgan Trans Mountain expansion, and the TransCanada Keystone XL pipeline.

[176] Canadian Association of Petroleum Producers, "CAPP CANADIAN CRUDE OIL PRODUCTION FORECAST 2012 – 2030," June 2012, http://www.capp.ca/getdoc.aspx?Docid=209350&DT=NTV.

The Canadian National Energy Board also produced forecasts of growth in tar sands production which are compared to the CAPP forecasts in Figure 85. They are aggressive but less so than the CAPP growth forecast, which projects tar sands production to more than triple 2011 levels by 2030.

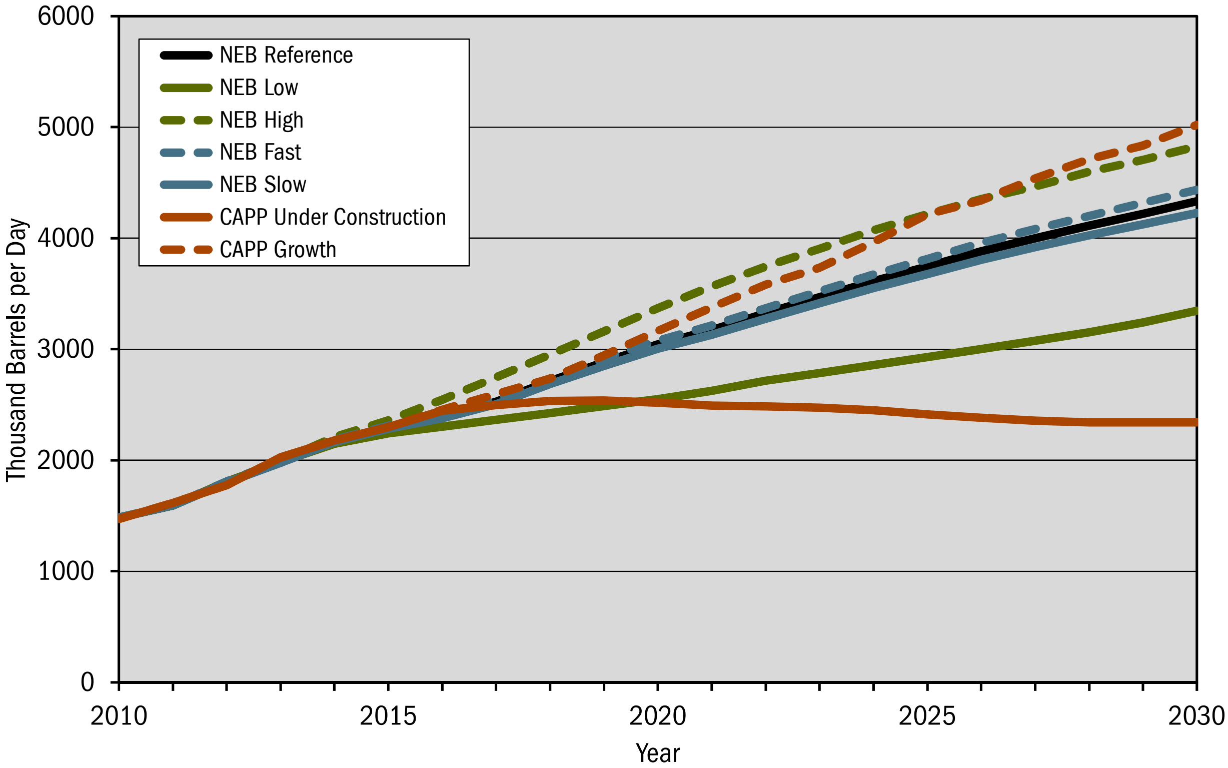

Figure 85. Canadian tar sands production forecasts by NEB (2011) and CAPP (2012), 2010-2030.[177]

177 National Energy Board, "Canada's Energy Futures," 2011, Appendix, Tables 3-31, 3-32, 3-33, 3-34, 3-35, A 14% volume loss is assumed in converting bitumen to synthetic crude oil, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035ppndc-eng.zip; CAPP forecast from http://www.capp.ca/getdoc.aspx?Docid=209350&DT=NTV.

How realistic are these projections? Growth in tar sands production through construction of new projects in the last decade proceeded at a frenzied pace. This resulted in cost inflation and logistical nightmares as companies scrambled for labor and materials to complete projects. The average rate of growth in production over this period was slightly less than 100,000 barrels per day each year. And yet, the reference case forecast of the NEB calls for this rate of growth to increase by 90 percent by 2015 and remain above 2000-2011 levels for the entire period through 2035 (Figure 86).

These projections of future growth are likely untenable in light of the logistical bottlenecks in building infrastructure over the past decade (and at a much slower rate of growth). In fact, the high cost of building new production infrastructure is now causing companies to put expansion plans on hold. Total, who received Federal Government approval for the Joslyn mine in late 2011, has yet to grant corporate approval to proceed with full development.[178] Other players such as Suncor and Canadian Natural Resources Limited are also cutting back.[179]

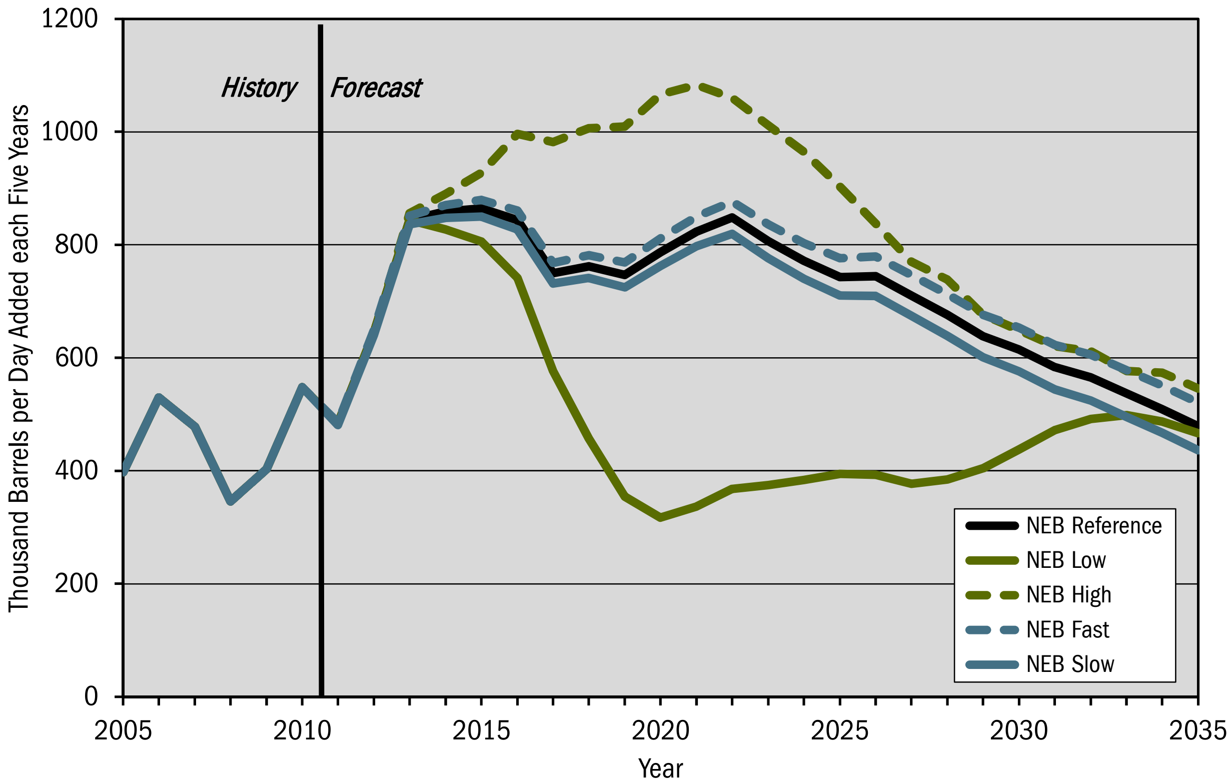

Figure 86. Five-year rates of addition in Canadian bitumen production implied by NEB forecasts through 2035.

The reference case increases in production, which are projected to grow by 90 percent in 2015 over 2000-2011 levels, are likely untenable given experience in logistical bottlenecks building infrastructure over the past decade.[180]

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178 Nathan Vanderklippe, "A reality check for the promise of the oil sands", *Globe and Mail*, September 22,2012, http://www.theglobeandmail.com/globe-investor/a-reality-check-for-the-promise-of-the-oil-sands/article4560688.

179 Chip Cummins, "Mining Canada's Oil Sands: Suddenly not a sure thing", *Wall Street Journal*, November 1, 2012, http://online.wsj.com/article/SB10001424052970204005004578080733669452700.html.

180 National Energy Board, "Canada's Energy Futures," 2011, Appendix, Tables 3-31, 3-32, 3-33, 3-34, 3-35, A 14% volume loss is assumed in converting bitumen to synthetic crude oil, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035ppndc-eng.zip.

Government forecasts for tar sands production have always been overly optimistic. Figure 87 illustrates eight years of Alberta Government forecasts and the latest NEB forecasts compared to an extension of the frenzied pace of the last decade. This has important implications on the need (or likely lack thereof) for new export pipelines being promoted by industry and the Canadian Federal and Provincial governments. The CAPP growth forecast, for example, would require 27 new 100,000 barrel per day projects, or many more smaller projects, to be funded and built by 2030—now just 17 years away. Given that the projects with the most favorable geology and economics are being pursued now, projects further down the road can be expected to be increasingly more marginal and therefore more difficult to justify economically. Yet another factor potentially restricting future growth is the imposition of further regulatory impediments to carbon emissions and other environmental impacts.

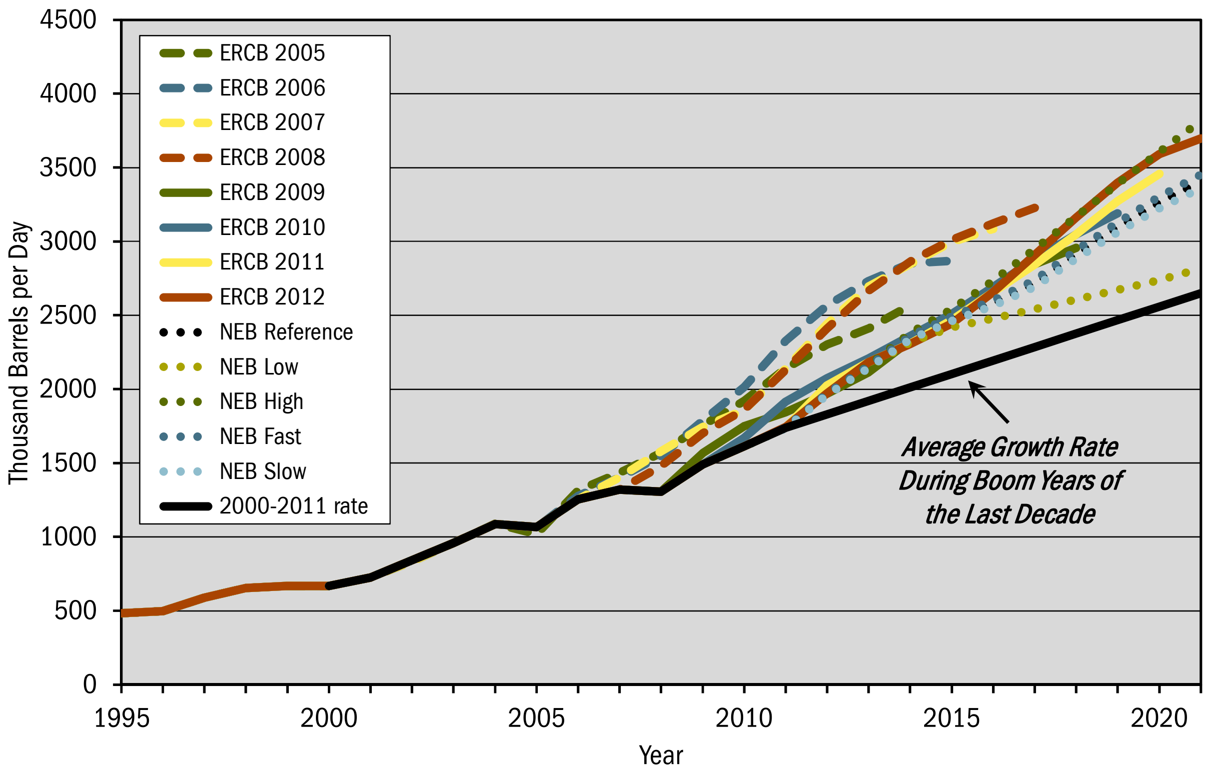

Figure 87. Alberta bitumen production forecasts, ERCB (2005-2012) and NEB (2011) compared to projection of actual 2000-2011 growth rates, through 2021.[181]

[181] National Energy Board, "Canada's Energy Futures," 2011, Appendix, Tables 3-31, 3-32, 3-33, 3-34, 3-35, http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035ppndc-eng.zip; Alberta Energy Resources Conservation Board forecasts from ST-98 reports dated 2005 through 2012, http://www.ercb.ca/data-and-publications/statistical-reports/st98 .

Costs and EROEI

Bitumen production from the tar sands is high-cost, exceeding most estimates of tight oil plays when upgraded to synthetic crude oil. Breakeven costs for mining with upgrading are over $100 per barrel. Bitumen production is also energy intensive, requiring extensive amounts of natural gas for energy in the extraction process and hydrogen inputs for upgrading.

Table 10 illustrates estimated EROEI of in situ and mined bitumen, along with capital costs to construct the infrastructure to produce it, estimated breakeven supply costs, and the amount of energy from purchased gas needed to produce it. Although the mean EROEI of mined bitumen is relatively high at 12.4:1, the bitumen needs to be upgraded somewhere before it can be used, and therefore 5.0:1 is the appropriate metric for the end product. In situ recoverable bitumen, which comprises 80 percent of the resource, starts at a mean EROEI of 5.0:1 and is much lower at 2.9:1 when upgraded.

	Cost per Barrel of Production Capacity ($Can/barrel)			Estimated Supply Cost ($US WTI per barrel)			Purchased Natural Gas (mcf/barrel)			Energy Returned on Energy Invested (EROEI) Including Purchased Gas Only		
	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Max	Min	Mean
Stand-alone mine	55,000	75,000	65,000	70	91	80.5	0.4	0.6	0.5	15.5:1	10.3:1	12.4:1
Mine with Upgrading	85,000	105,000	95,000	96.5	110.5	103.5	0.9	1.1	1	5.6:1	4.6:1	5.0:1
In Situ (SAGD)	25,000	50,000	37,500	50	78	64	1	1.5	1.25	6.2:1	4.1:1	5.0:1
In Situ (SAGD) with Upgrading	-	-	-	-	-	-	1.5	2	1.75	3.3:1	2.5:1	2.9:1

Table 10. Capital costs of infrastructure for bitumen and synthetic crude oil production, supply costs, purchased natural gas required, and energy returned on energy invested (EROEI).[182]

Steam-Assisted Gravity Drainage (SAGD) is the predominant method of in situ extraction.

Bear in mind that these estimates of EROEI are the *best* case. They do not include the embodied energy costs of infrastructure such as upgraders, pipelines, trucks and shovels, as well as diesel fuel and other energy inputs into the recovery process. They also do not include the energy cost of importing diluents to move bitumen through pipelines, or the energy cost of moving dilbit to markets. Although difficult to calculate precisely, these additional inputs would likely reduce the EROEI of upgraded in situ bitumen to around 2.4:1 and mined bitumen to 4.5:1 or less. Furthermore, considering that the highest quality

[182] EROEI calculations by the author. Production, supply costs and purchased gas requirements from Alberta Energy Resources Conservation Report ST-98-2012, Table 3-10, http://www.ercb.ca/data-and-publications/statistical-reports/st98; Costs of mining and upgrading production from National Energy Board, 2011, "Canada's Energy Futures"; http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2011/nrgsppldmndprjctn2035-eng.pdf; Estimates of supply costs of mining with upgrading were estimated from Alberta Energy Resources Conservation Board ST-98-2011 report with $8.50 per barrel added which is the average increment used in the ST98-2012 report for stand-alone mining; purchased gas requirements for upgrading bitumen is from Alberta Chamber of Resources, 2004, Oil Sands Technology Roadmap: Unlocking the Potential", page 14, "upgraders need as much as 500 cubic feet per barrel of synthetic crude for energy and hydrogen today, and this will climb as synthetic crude quality demands increase", http://www.acr-alberta.com/LinkClick.aspx?fileticket=48xNO8LRbKk%3d&tabid=205; calculation of EROEI allows for the 14% reduction in volume from the conversion of bitumen to synthetic crude oil (SCO) as well as the slightly lower energy content of SCO; the costs of SAGD production and supply costs with upgrading are not estimated as most SAGD production is sold as bitumen without upgrading – nonetheless this energy cost must be incurred somewhere hence the estimates of EROEI.

resources are being recovered first, the EROEI can be expected to decrease over time as the surface-mineable resources are exhausted and in situ operations move into more marginal areas.

Environmental Considerations

Environmental issues with the tar sands are legion. They include:

- Water use and disposal. An estimated two to four barrels of water are required per barrel of oil produced. Leakage of water from tailings ponds contributes to contamination of ground- and surface-water.[183,184]

- Air emissions. On a life-cycle basis the greenhouse gas emissions of the tar sands extraction process are three to four times that of the extraction of conventional oil.[185] On a well-to-wheels basis, tar sands emit on the order of 23% more greenhouse gases, as the bulk of greenhouse gas emissions occur in the tank-to-wheels part of the process.[186]

- Surface land disturbance footprint. Although all tar sands operations must by law be reclaimed eventually, the proportion that has actually been reclaimed after more than forty years of operations is miniscule.

An idea of the level of surface disturbance undergone to grow tar sands production from 0.17 million barrels per day in 1984 to 1.6 million barrels per day in 2011 is illustrated in Figure 88. This surface footprint would grow immensely under the CAPP growth forecast which projects production of more than triple 2011 levels by 2030.

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183 Canadian Association of Petroleum Producers, "Water Use in Canada's Oil Sands", 2011, http://www.capp.ca/getdoc.aspx?DocId=193756&DT=NTV.

184 Pembina Institute, "Water Impacts", 2010, http://www.pembina.org/oil-sands/os101/water.

185 Pembina Institute, "Climate Impacts", 2010, http://www.pembina.org/oil-sands/os101/climate.

186 Natural Resources Defense Council, "Report: Fuel from Canadian Tar Sands Significantly Dirtier Than Average", February 9, 2011, http://switchboard.nrdc.org/blogs/smui/european_commission_report_fin.html.

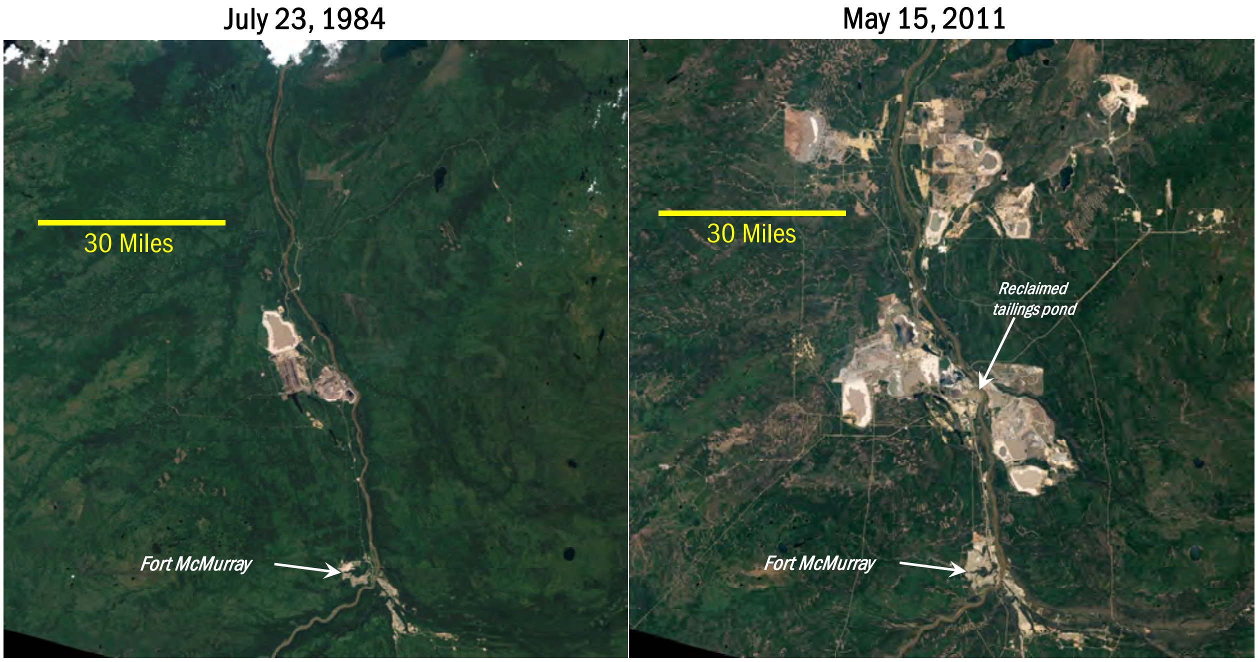

Figure 88. Surface footprint growth of tar sands development from 1984 (0.17 mbd) to 2011 (1.6 mbd).

The CAPP growth forecast calls for production to more than triple 2011 production levels by 2030, just 18 years away.

The tar sands are no panacea for "energy independence." At best, they may add a net increase of two to three million barrels per day over and above the decline in Canada's conventional oil production over the next two decades. Moreover, given Canada's own domestic requirements and its declining conventional oil production, surplus for export will grow only modestly and will decline in the longer term if Canada chooses to look after its own needs first by constructing new pipeline capacity to the eastern part of the country which is now dependent on foreign imports.

A small tar sands operation is also under development in Utah operated by Canadian interests. This project is a mountain-top strip mine with initial production of 2,000 barrels per day with a target to scale up production to 50,000 barrels per day within a decade,[187] which is insignificant in the face of U.S. requirements but a possible niche source of oil. A now outdated assessment by the U.S. Department of Energy suggests that Utah may have 11 billion barrels of recoverable tar sands, although none of this resource has been recovered to date.[188]

[187] Yadullah Hussain, "Calgary-based company plans first U.S. oil sands project", *National Post*, November 8, 2012, http://business.financialpost.com/2012/11/08/calgary-based-company-plans-first-u-s-oil-sands-project/.
[188] U.S. Department of Energy, "Fact Sheet: U.S. Tar Sands Potential", undated (accessed February 2013), http://www.fossil.energy.gov/programs/reserves/npr/Tar_Sands_Fact_Sheet.pdf.

Oil Shale

Vast in situ resources of oil shale (not to be confused with "shale oil," i.e., tight oil) are widely distributed around the world, but have never been produced at significant rates. The U.S. is thought to have at least half of the world's resources in the Green River Formation of Utah, Colorado and Wyoming,[189] which has made it a common subject of "energy independence" rhetoric. The term oil shale is somewhat of a misnomer as it is not, in fact, oil, but rather kerogen, which is organic matter that has not been exposed to the temperatures and pressures required to convert it to oil.[190] As a result, conversion of oil shale into useful petroleum liquids requires intense inputs of heat over extended time periods. Oil shale can also be burned directly as a source of heat for power generation as has been done in Europe and Asia for many years at small scales. In this mode it has about half the heat content of low-grade lignite coal.

The vast majority of oil shale used in the world has come from mining operations (mainly surface but with some underground), with either conversion to petroleum liquids through surface retorting or direct combustion for power generation. Figure 89 illustrates the use of oil shale by country over the past century. Peak consumption occurred in 1980, at about 18,400 barrels oil equivalent per day, or less than two hundredths of one percent of world petroleum liquids consumption. This illustrates the fundamental conundrum with oil shale: only a tiny fraction of the vast purported resources are recoverable with mining methods, and extensive pilot experiments with various in situ recovery schemes have yet to produce oil at commercial rates. Yet 800 billion barrels are said to be recoverable by the IEA at prices of $50-$100 per barrel (in 2008 dollars) as illustrated in Figure 36. Given past experience this is wishful thinking at best.

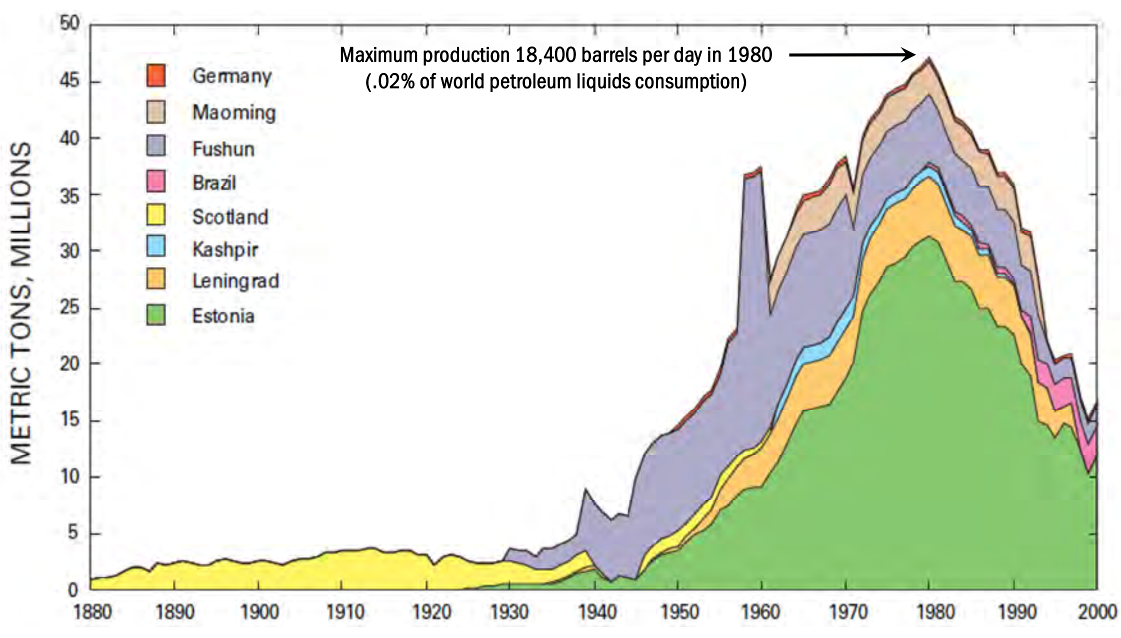

Figure 89. Oil shale production in Estonia, Russia (Leningrad and Kashpir), Scotland, Brazil, China (Fushun and Maoming) and Germany, 1880-2000.[191]

Peak production in 1980 is equivalent to 18,400 barrels per day.

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[189] J.R. Dyni, "Geology and Resources of Some World Oil-Shale Deposits." USGS Scientific Investigations Report 2005-5294, 2005, http://www.scribd.com/doc/31421740/World-Oil-Shale-Deposits-USGS.

[190] R.L. Kleinberg, et al., "Topic Paper #27: Oil Shales", National Petroleum Council, July 18, 2007, http://downloadcenter.connectlive.com/events/npc071807/pdf-downloads/Study_Topic_Papers/27-TTG-Oil-Shales.pdf

[191] J.R. Dyni, "Geology and Resources of Some World Oil-Shale Deposits." USGS Scientific Investigations Report 2005-5294, 2005.

The oil shale deposits of most interest in the U.S. are located in Wyoming, Colorado, and Utah within the Piceance, Uinta, and Greater Green River basins (Figure 90). The USGS has recently completed updated estimates of the in situ resources in all three basins with a total aggregate estimate of over four trillion barrels.

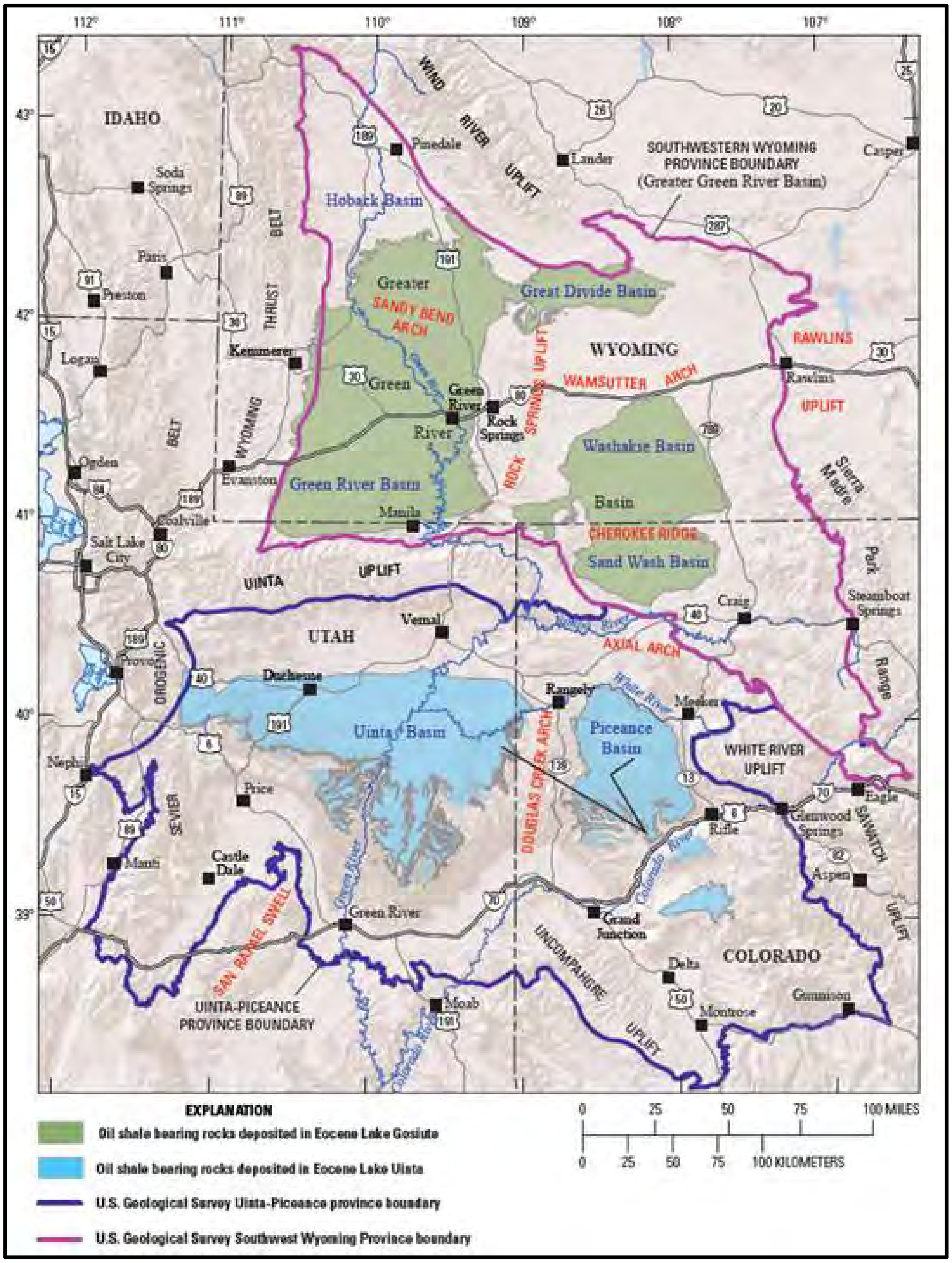

Figure 90. Location of oil shale deposits in the Uinta, Piceance, and Greater Green River basins of Wyoming, Utah, and Colorado.[192]

[192] T.J. Mercier, and R.C. Johnson, "Isopach and isoresource maps for oil shale deposits in the Eocene Green River Formation for the combined Uinta and Piceance Basins, Utah and Colorado", U.S. Geological Survey Scientific Investigations Report 2012–5076, 2012, http://pubs.usgs.gov/sir/2012/5076/.

Table 11 illustrates the wide variation in the concentration of in-place oil between the basins, with the Piceance having on average nearly four times the concentration of the other basins. The best townships in the Greater Green River Basin (which comprise less than four percent of the area assessed), for example, are only half the average concentration within the Piceance.[193] Within the Piceance (Table 12) there is also a wide variation in quality, with the best (containing more than 25 gallons of oil per ton of oil shale) comprising less than a quarter of the total resource. A comparable estimate for the Greater Green River Basin indicates that less than ten percent of the resource contained greater than 15 gallons of oil per ton of oil shale.[194]

Basin	Area (square miles)	In Situ Resource (billion barrels)	Average Concentration (billion barrels per square mile)
Greater Green River Basin	5500	1440	0.262
Uinta Basin	3834	1320	0.344
Piceance Basin	1335	1522	1.146
Total	**10669**	**4282**	**0.402**

Table 11. USGS estimates of in situ oil shale resources and average oil concentration within the Uinta, Piceance, and Greater Green River basins.[195]

Oil Concentration	In Situ Resource (billion barrels)	Percentage of Total
Less than 15 gallons per ton of oil shale	602	39.6
15 to 25 gallons per ton of oil shale	568	37.3
Greater than 25 gallons per ton of oil shale	352	23.1
Total	**1522**	**100**

Table 12. Oil concentration in gallons per ton of in situ oil shale resources in the Piceance Basin.[196]

Thus it can be seen that with oil shale, as with all hydrocarbon accumulations, there are variations in quality between basins and there are sweet spots within basins. For this reason, the relatively high quality oil shale resources within the Piceance Basin have received the most attention in recent years with pilot projects conducted by oil majors Shell, Chevron, and ExxonMobil, as well as a number of smaller companies.[197] None of these pilots have resulted in commercial scale production and Chevron has recently abandoned its operations.[198] There is also a surface mining and retorting pilot project in

[193] R. C. Johnson, T.J. Mercier, R.T. Ryder, M.E. Brownfield, and J.G. Self, "Assessment of In-Place Oil Shale Resources of the Green River Formation, Greater Green River Basin in Wyoming, Colorado and Utah," U.S. Geological Survey Fact Sheet FS-2011-3063, 2011, http://pubs.usgs.gov/fs/2011/3063/.
[194] T.J. Mercier, R.C. Johnson, and M.E. Brownfield, "In-Place Oil Shale Resources Underlying Federal Lands in the Green River and Washakie Basins, Southwestern Wyoming," U.S. Geological Survey Fact Sheet FS-2011-3113, 2011, http://pubs.usgs.gov/fs/2011/3113/.
[195] Ibid.
[196] Ibid.
[197] National Oil Shale Association, "Oil Shale Update," 2012, http://www.oilshaleassoc.org/documents/OSU-June-2012-3.pdf.
[198] Troy Hooper, "Chevron giving up oil shale research in western Colorado to pursue other projects", *The Colorado Independent*, February 29, 2012, http://coloradoindependent.com/114365/chevron-giving-up-oil-shale-research-in-western-colorado-to-pursue-other-projects.

the Uinta Basin of eastern Utah operated by Enefit American Oil.[199] A good review of the companies that are or have invested in oil shale has been published by the U.S. Department of Energy.[200]

Most of the very limited use of oil shale in the U.S. has focused on surface mining and retorting, a messy process which leaves large volumes of spent rock and other environmental problems. In situ conversion processes likely hold the most long term promise for extracting significant volumes but are years or decades away—or perhaps never. Two of these, the Shell freeze-wall in situ conversion process (ICP) and the ExxonMobil "electrofrac" process illustrate some of the challenges and massive energy inputs required:

- In the Shell freeze-wall process:

  A freeze wall is constructed to isolate the processing area from surrounding groundwater. Two-thousand-foot-deep wells, eight feet apart, are drilled and filled with a circulating super-chilled liquid to cool the ground to −60 °F. Water is then removed from the working zone. Heating and recovery wells are drilled at 40 foot intervals within the working zone. Electrical heating elements are lowered into the heating wells and used to heat oil shale to between 650 °F and 700 °F over a period of approximately four years. Kerogen in oil shale is slowly converted into tight oil and gases, which then flow to the surface through recovery wells.[201]

- In the ExxonMobil process:

  The Electrofrac process is designed to heat oil shale in-situ by conducting electricity through induced fractures in the shale that have been filled with conductive material to form a resistive heating element. Heat flows from the fracture into the oil shale formation, gradually converting the oil shale's solid organic matter into mobile oil and gas, which can be produced by conventional methods.[202]

Shell has recently shut down its freeze-wall pilot having declared it a "success" and Intek notes that *"many years of research and development will be required to demonstrate the technical, environmental, and economic feasibility"* of the ExxonMobil process. As noted earlier, Chevron has shut down its pilot project using its proprietary "CRUSH" in situ technology. So despite decades of research and experimentation, and hundreds of millions of dollars spent, there is still no significant production from oil shale.

Many estimates of net energy (or EROEI) have been made for oil shale. Most are very low given the amount of energy required for oil shale production. A summary of recent estimates and a discussion of the issues in calculating the EROEI of oil shale is given by Cleveland et al.[203] Cleveland points out that "*the EROI for oil shale should be regarded as preliminary or speculative due to the very small number of operating facilities that can be assessed*". He suggests that the EROEI is about 1.5:1 considering internal energy used in the process and between 2.6:1 and 6.9:1 considering only external "purchased" energy, which puts it in the range of tar sands. Furthermore, considering the wide range in quality of oil

[199] National Oil Shale Association, "Oil Shale Update," 2012, http://www.oilshaleassoc.org/documents/OSU-June-2012-3.pdf.
[200] U.S. Department of Energy, "Secure Fuels from Domestic Resources", Intek, 2011, http://www.unconventionalfuels.org/publications/reports/SecureFuelsReport2011.pdf.
[201] See citations in "Shell in situ conversion process: Process", Wikipedia, accessed January 2013, http://en.wikipedia.org/wiki/Shell_in_situ_conversion_process.
[202] U.S. Department of Energy, "Secure Fuels from Domestic Resources".
[203] C.J. Cleveland and P.A. O'Conner, "Energy Return on Investment (EROI) of Oil Shale", *Sustainability* 2011, 3, 2307-2322; doi:10.3390/su3112307.

shale, the EROEI will be much lower or negative for the bulk of the resource as existing operations have focused on the highest quality resources.

Collateral environmental impacts of oil shale development are high water usage (the oil shale deposits are located in very arid territory), the surface footprint of infrastructure, and greenhouse gas emissions which are significantly higher than for conventional oil.[204] The water issues have been studied by the Government Accountability Office, which estimates that water use may be as high as 12 barrels per barrel of oil for in situ operations, and as high as five per barrel of oil for surface operations.[205]

Oil shale production is thus not only net-energy-limited but is an extreme example of a rate-limited resource, as there is no significant production now nor is there likely to be in the foreseeable future. Notwithstanding these limitations, the IEA in its latest World Energy Outlook has listed a trillion barrels of oil shale as "technically recoverable" in the Americas (they do not state any timeframe over which they expect this to happen).[206]

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[204] Ibid.

[205] Government Accountability Office, "ENERGY-WATER NEXUS A Better and Coordinated Understanding of Water Resources Could Help Mitigate the Impacts of Potential Oil Shale Development," 2010, http://www.gao.gov/assets/320/311896.pdf.

[206] World Energy Outlook 2012, IEA, page 101, http://www.worldenergyoutlook.org/.

Arctic and Deepwater Oil

Although technically not unconventional oil (it is included in the IEA estimates of conventional crude oil), the deepwater and the Arctic are unconventional locales demanding the latest in drilling and production technologies. The U.S. Bureau of Ocean Energy Management (BOEM) has produced a new assessment of undiscovered technically recoverable oil and gas resources for the outer continental shelf areas illustrated in Figure 91.

Figure 91. Location of U.S. outer continental shelf oil and gas assessment areas.[207]

[207] U.S. Bureau of Ocean Energy Management, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011", http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Resource-Assessment/2011-RA-Assessments.aspx.

The Gulf of Mexico contains by far the highest potential in terms of reserves and undiscovered technically recoverable resources as illustrated by Figure 92. Although there have been moratoriums in place to prevent exploitation of the Atlantic, most of the Pacific and the eastern Gulf of Mexico, these regions comprise only 15 percent of the total estimated undiscovered technically recoverable resources. For example, the mean undiscovered technically recoverable estimate of 3.3 billion barrels for the entire Atlantic coast, if it could be recovered, would supply the U.S. for less than six months. The Pacific coast north of southern California where the current bans are in place, at 4.9 billion barrels, would last less than 10 months. Of the total remaining resources shown in Figure 92, only ten percent are actually proved reserves. The balance are probabilistic estimates based on limited input data. There are also likely significant undiscovered deepwater resources in Mexico's portion of the Gulf of Mexico, although its offshore Cantarell Field, and Mexico's oil production in general, have been in decline since 2004. Canada is also producing less than 0.3 mbd off the east coast of Newfoundland (although from relatively shallow water depths).

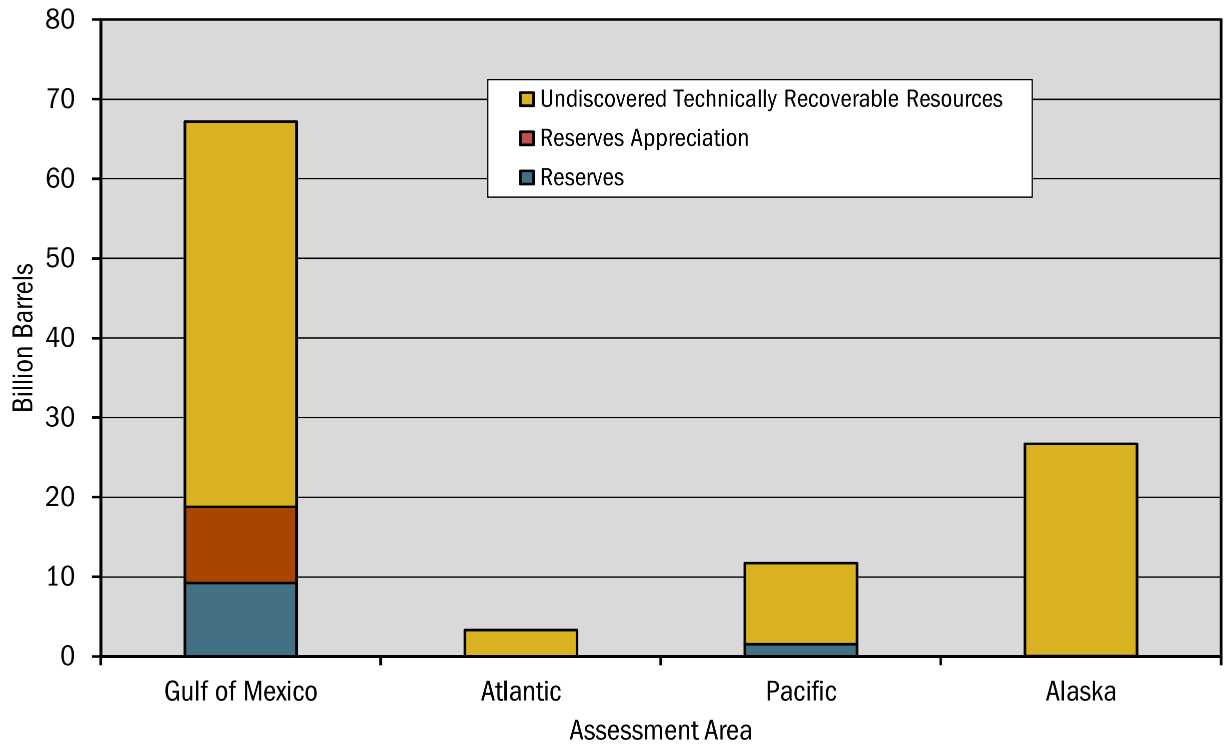

Figure 92. Remaining reserves and undiscovered technically recoverable oil resources in the U.S. outer continental shelves.[208]

Note that "Reserves Appreciation" are estimates which are not necessarily proved.

[208] Ibid.

BOEM estimated the potential recovery costs of the U.S. undiscovered technically recoverable oil resources (Figure 93). It suggests that 70 billion barrels, or 79 percent of the total, could be extracted at a cost of $90 per barrel or less. This would require lifting the moratoriums on all coasts, developing all outer continental shelves and accepting the environmental risks which were the reason that the moratoriums were imposed in the first place. It would also mean developing the Chukchi and Beaufort Seas in the Arctic, which contain 90 percent of Alaska's offshore potential.

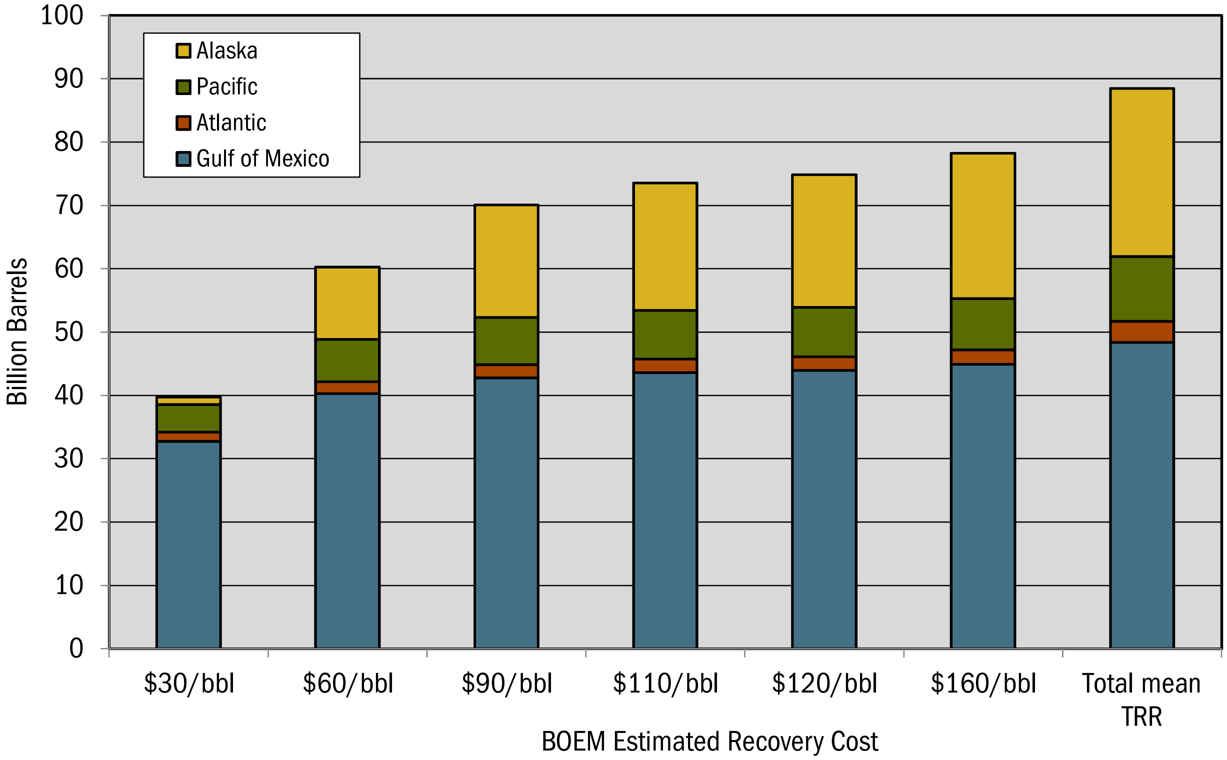

Figure 93. Estimated recovery cost of undiscovered technically recoverable oil resources in the U.S. outer continental shelves (BOEM, 2012).[209]

[209] Ibid.

Deepwater exploration is the last frontier. Wells are very expensive, costing $100 million or more each. Ultra-deepwater rigs rent at $600,000 to $700,000 per day, and demand is booming.[210] Wells can be very productive with initial rates of 50,000 barrels per day or more, yet declines can be high (although nothing like the steep decline rates of tight oil wells reviewed earlier).[211] Energy analyst Jean Laherrère suggests that global deepwater production will continue to grow from 6.7 mbd in 2010 to 11.5 mbd in 2024, after which production will fall.[212] U.S. deepwater production is projected to remain at1.7 mbd or less through 2035, or about one quarter of total crude oil production (see Figure 29).

The environmental risks of deepwater oil production were spectacularly highlighted with the BP Macondo spill in the Gulf of Mexico in 2010, which resulted in tens of billions of dollars in damages and $4.5 billion in criminal fines for BP.[213] Such risks are impossible to reduce to zero given the harsh and unpredictable environments being explored.

Arctic offshore exploration adds another layer of risk as it is conducted in frigid, ice-choked waters. Whereas the high water temperatures in the Gulf of Mexico served to disperse and degrade the Macondo spill relatively quickly, the remnants of the Exxon Valdez spill in Alaska which occurred nearly 25 years ago are still visible. Unpredictable ice movements and icebergs pose a threat to rigs unlike anything experienced further south. Shell experienced some of these challenges when it attempted to initiate drilling in the Chukchi Sea in September 2012.[214,215]

Deepwater oil is projected to be a stable part of U.S. oil supply but will make up less than ten percent of projected U.S. consumption for the next two decades and longer. Opening up coastal areas currently under moratoriums would expand access to relatively minor additional resources, compared to the Gulf of Mexico, while posing environmental risks to much broader coastal regions. Arctic offshore oil production is unlikely to be more than a niche supply for the foreseeable future.

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210 David Welhe, "Transocean Biggest Winner From 28% Jump in Oil Rig Rates: Energy", Bloomberg, March 28, 2012, http://www.bloomberg.com/news/2012-03-27/transocean-biggest-winner-from-28-jump-in-oil-rig-rates-energy.html

211 Jean Laherrère, "Deepwater GOM: Reserves versus Production - Part 3: Older Fields and Conclusion", The Oil Drum, November 23, 2011, http://www.theoildrum.com/node/8604.

212 Ibid.

213 C. Krauss and J. Schwartz, "BP Will Plead Guilty and Pay Over $4 Billion", *The New York Times*, November 14, 2012, http://www.nytimes.com/2012/11/16/business/global/16iht-bp16.html.

214 J.M. Broder, "Shell Halts Arctic Drilling Right After It Began", *The New York Times*, September 10, 2012, http://green.blogs.nytimes.com/2012/09/10/shell-halts-arctic-drilling-right-after-it-began/.

215 Tracy Watson, "In Kulluk's Wake, Deeper Debate Roils on Arctic Drilling", National Geographic News, January 14, 2013, http://news.nationalgeographic.com/news/2013/130112-in-kulluks-wake-deeper-debate-roils-on-arctic-drilling/

Extra-Heavy Oil

Ninety percent of the world's extra-heavy oil is contained in Venezuela's Orinoco extra heavy oil belt, which is purported to be an even larger source of unconventional oil than the Canadian tar sands. Although it lies outside of North America, it is included here as Venezuela has historically been a large exporter to the U.S. and much of the refining capacity along the U.S. Gulf Coast is adapted to Venezuela heavy crude oil. Extra-heavy oil is slightly lighter in gravity on average (4-16 API) than bitumen from the Canadian tar sands and hence is easier to move and refine, although it still requires upgrading to make it useful.

The Orinoco Belt comprises 55,000 square miles straddling the 1,330 mile long Orinoco River.[216] The Orinoco Basin is one of the lushest in South America and the world. Figure 94 outlines the limits of the Orinoco Belt within which the USGS has estimated a mean unproved technically recoverable resource of 513 billion barrels.[217]

Figure 94. Location of Orinoco extra-heavy oil belt within Venezuela.[218]

[216] Sarah Wykes, "Venezuela – The Orinoco Belt", Heinrich Boll Stiftung, 2012, http://www.boell.de/intlpolitics/energy/resource-governance-tar-sands-venezuela-15659.html.
[217] C.J. Schenk, et al., "An Estimate of Recoverable Heavy Oil Resources of the Orinoco Oil Belt, Venezuela", USGS, 2010, http://pubs.usgs.gov/fs/2009/3028/pdf/FS09-3028.pdf.
[218] Ibid.

The USGS was careful to qualify its estimates of unproved technically recoverable resources with the following statements:

> *No attempt was made in this study to estimate either economically recoverable resources or reserves within the Orinoco Oil Belt AU. Most important, these results do not imply anything about rates of heavy oil production or about the likelihood of heavy oil recovery. Also, no time frame is implied other than the use of reasonably foreseeable recovery technology.*[219]

In fact, notwithstanding these very large estimates of in situ resources, Venezuela's oil production peaked in 1970 as illustrated in Figure 95. Although domestic consumption of oil has been rising, total oil production and U.S. exports have been falling since 1998.

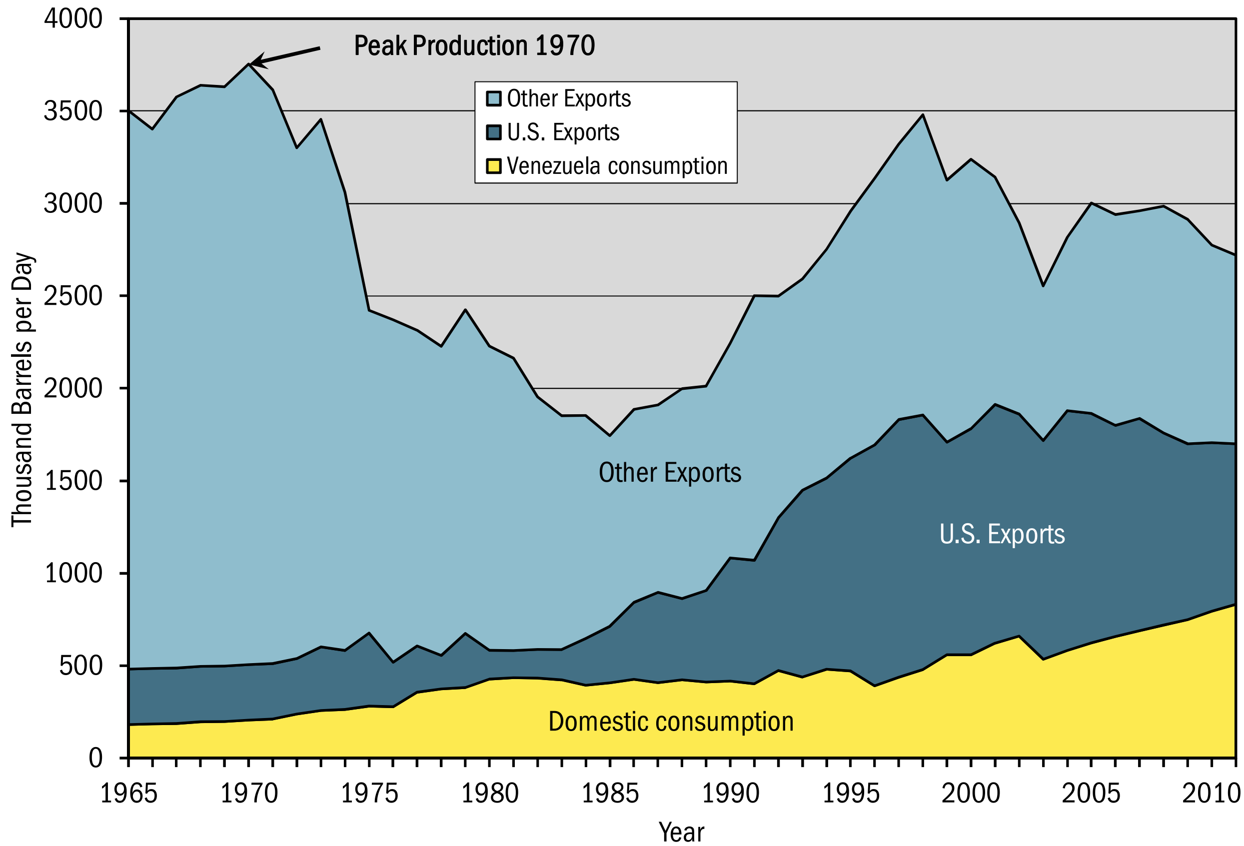

Figure 95. Venezuela oil production and allocations, 1965-2011.[220]
Venezuelan oil production peaked in 1970.

[219] Ibid., page 3.
[220] U.S. exports from EIA, http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=MCRIMUSVE2&f=A; U.S. exports estimated for 1965-1972 period; Venezuela production and consumption data from BP, *Statistical Review of World Energy*, 2012.

The Venezuelan state-owned petroleum company Petroleos de Venezuela (PDVSA) "certified" 215 billion barrels of "reserves" in the Orinoco Belt in its 2010 annual report.[221] This brought the total "reserves" of the country to 296.5 billion barrels, making it the number one holder of oil reserves in the world. This completed a near four-fold increase in reported Venezuelan reserves in a mere six years since 2005, while at the same time production continued to fall as illustrated in Figure 96. The CATO Institute has declared this ramp up in reported reserves "seriously fraudulent", as it is based on rudimentary data which is inadequate to quantify a "reserve".[222] Nonetheless, the widely cited BP Statistical Review of World Energy has accepted the claim and including 296.5 billion barrels of oil for Venezuela in its world estimates.[223]

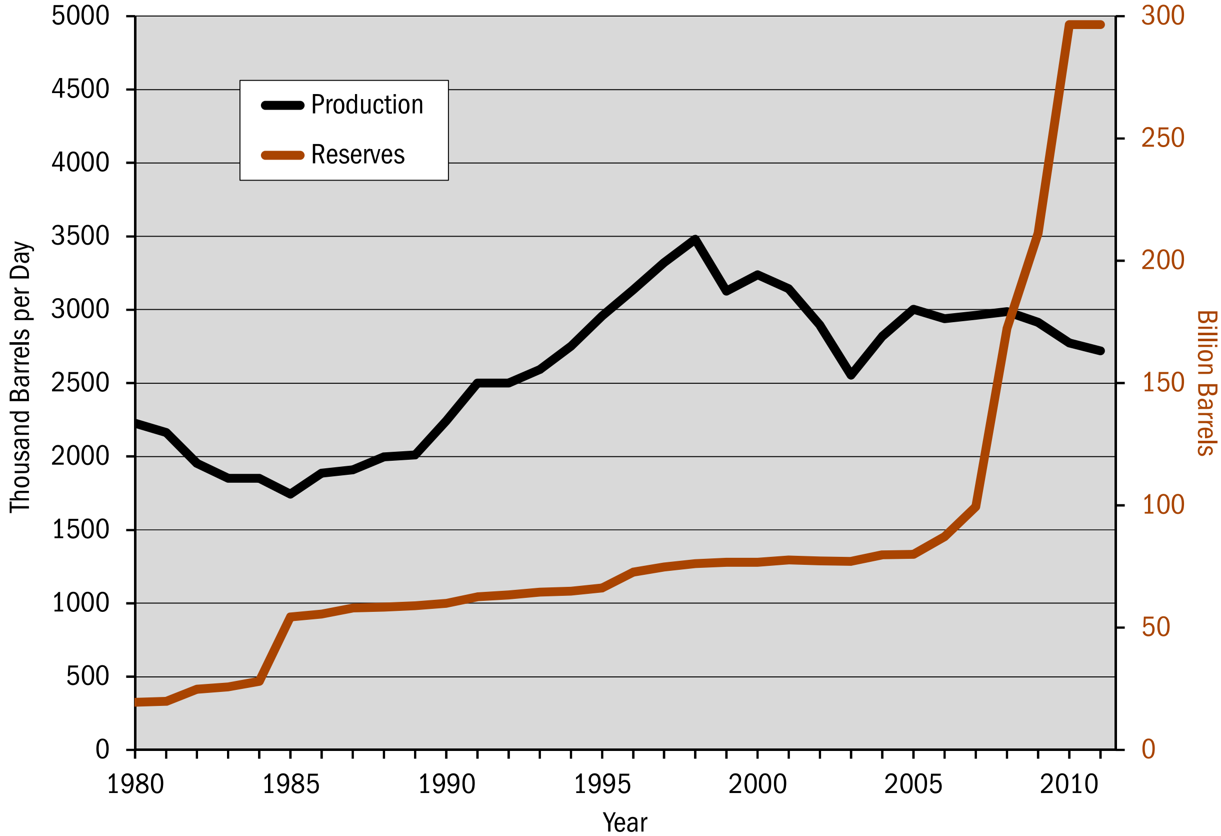

Figure 96. Venezuela oil production and reported reserves, 1980-2011.[224]

[221] G. Coronel, "The Curious 2010 Annual Report of Petroleos de Venezuela", CATO Institute, 2011, http://www.cato.org/publications/commentary/curious-2010-annual-report-petroleos-de-venezuela.
[222] Ibid.
[223] BP, *Statistical Review of World Energy*, 2012.
[224] Ibid.

The Chavez Government in Venezuela has stated that it plans to double oil production by 2019, most of which would have to come from the Orinoco Belt. It is highly questionable if production will grow at all given the failure of earlier schemes and the generally high debt levels of PDVSA, which is used as a piggy bank by the Chavez Government to fund a wide variety of social programs. Wykes offers a good recent review of the debt issues and foreign investment risks in Venezuela oil production.[225]

Given its political issues, Venezuela offers a good example of "above ground" challenges to significantly growing production, notwithstanding significant "below ground" geological complexities. Reserves are likely overstated and growth must come from extra-heavy oil, which presents similar challenges to the Canadian tar sands. The application of thermal recovery technology, such as SAGD, means the recovered oil will likely have a comparatively low EROEI similar to that of in situ tar sands.

Thus Venezuela extra-heavy oil is both rate-constrained and net-energy limited, and is unlikely to provide significant new production to offset declines in world conventional crude oil production.

[225] Sarah Wykes, "Venezuela – The Orinoco Belt", Heinrich Boll Stiftung, 2012, http://www.boell.de/intlpolitics/energy/resource-governance-tar-sands-venezuela-15659.html.

Biofuels

Biomass is a significant contributor to primary energy consumption in the form of traditional wood-burning, burning as a primary fuel or in tandem with coal in power plants, and in the production of biofuels to displace oil in the transportation sector. Here we will focus on its use as a liquid fuel in the transportation sector as a substitute for oil.

Biofuels in the U.S. are primarily produced from corn, but are also produced from a variety of other food crops including sugarcane, soy beans and palm oil. Cellulosic ethanol refers to the use of non-food crops, or the non-edible parts of food crops, including corn stover, switch grass, jatropha and woody biomass – so far cellulosic ethanol has not proceeded past pilot scale to commercial demonstration. Production of biofuels from algae has also eluded commercialization despite several hundred million dollars spent on research. There is a large body of research on the issues associated with each of these sources and their ability to scale to meaningful volumes which are reviewed briefly below.

Liquid fuels produced from biomass include ethanol, which is used as a ten-percent blend (E10) in gasoline for most vehicles in the U.S. and up to 85 percent (E85) in specially designed flex-fuel vehicles. Biodiesel produced from biomass can be used as a complete substitute for petroleum-based diesel fuel (B100). The U.S. is the largest producer of biofuels in the world, with combined ethanol and biodiesel production of 1.06 mbd which amounts to about five percent of total consumption as illustrated in Figure 97 (these amounts also include petroleum additives to denature the ethanol to make it unsuitable for human consumption). The U.S. is also a net exporter of biofuels, and exported between 6 and 8 percent of ethanol production and 7 to 10 percent of biodiesel production over the past two years.

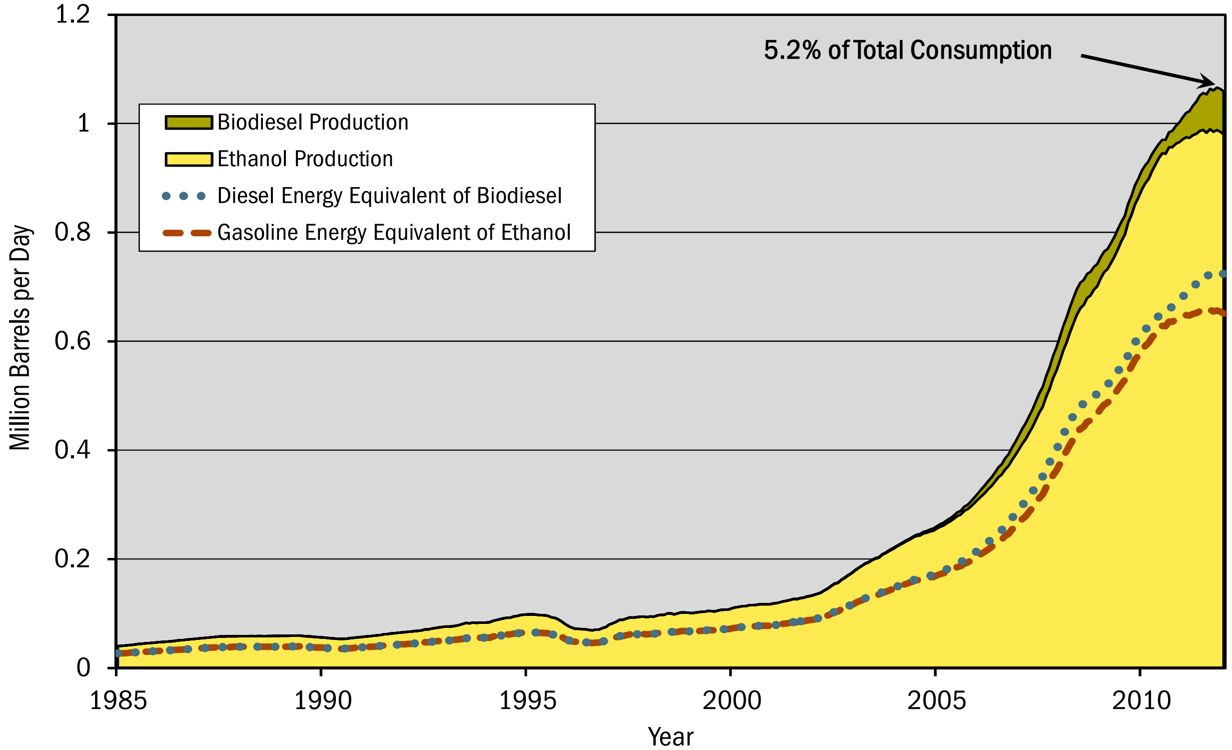

Figure 97. U.S. production of ethanol and biodiesel, 1985-2012,[226] **compared to equivalent amount of gasoline and #2 diesel fuel to provide same energy content.**[227]
Data include denaturing additives to make the ethanol unfit for human consumption.

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226 EIA, November, 2012, ethanol from http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T10.03 and biodiesel from http://www.eia.gov/totalenergy/data/monthly/query/mer_data_excel.asp?table=T10.04.

227 Ethanol converted at 76,100 btu/gallon vs 114,500 btu/gallon for gasoline, http://en.wikipedia.org/wiki/Gasoline_gallon_equivalent; biodiesel converted at 118,296 btu/gallon vs 129,500 btu/gallon for #2 diesel fuel, http://www.biodiesel.org/docs/ffs-basics/energy-content-final-oct-2005.pdf?sfvrsn=6.

Figure 98 illustrates the EIA's projection for biofuel production in the U.S. through 2040.[228] The EIA projects no net growth in either ethanol or biodiesel production by 2040, with significant production of "other biomass-derived liquids" increasing substantially only after 2030. This projection, at 1.13 mbd in 2035, is less than half of the projection the EIA made just six months earlier (2.37 mbd).[229]

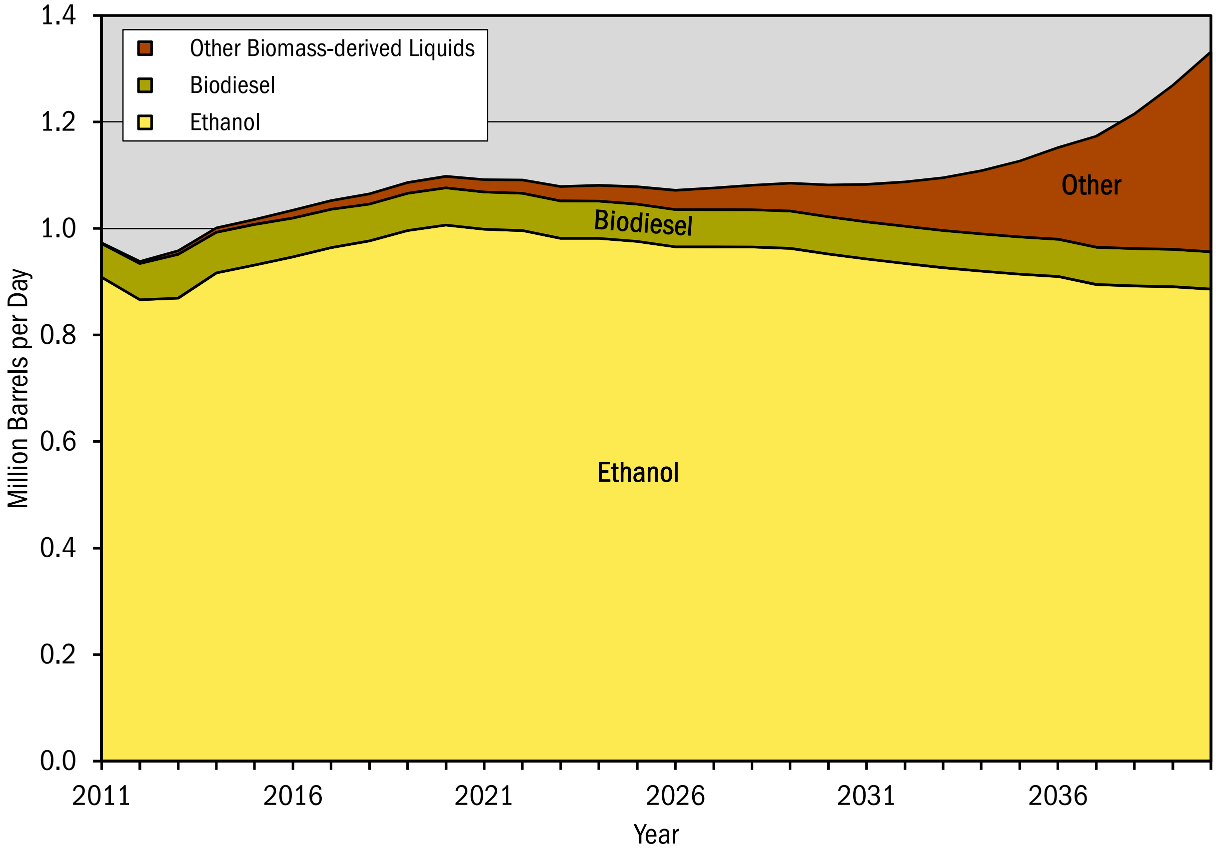

Figure 98. U.S. biofuel production forecast, 2011-2040 (EIA Reference Case, 2012).[230]
"Other" includes pyrolysis oils, biomass-derived Fischer-Tropsch liquids, and renewable feedstocks used for the onsite production of gasoline and diesel fuel.

228 EIA Annual Energy Outlook 2013, table 11.
229 EIA Annual Energy Outlook 2012, table 11, http://www.eia.gov/oiaf/aeo/tablebrowser/aeo_query_server/?event=ehExcel.getFile&study=AEO2012&region=0-0&cases=ref2012-d020112c&table=11-AEO2012&yearFilter=0.
230 EIA Annual Energy Outlook 2013, table 11.

The production of ethanol from corn in the U.S. may be approaching its limits. Production of corn has doubled since 1980 and the proportion of the crop utilized for ethanol production has increased from less than ten percent in 2000 to 45 percent in 2012 as illustrated in Figure 99. This implies the diversion of land to corn production from other food crops and increases in productivity from ever greater applications of petroleum-based fertilizers to the crop. Much of this growth was a result of subsidies of up to $6 billion per year which ended at the start of 2012. The federal and state renewable fuel standards, however, ensure the need for vast quantities of corn ethanol, which means continued diversion of the corn crop to ethanol production.[231]

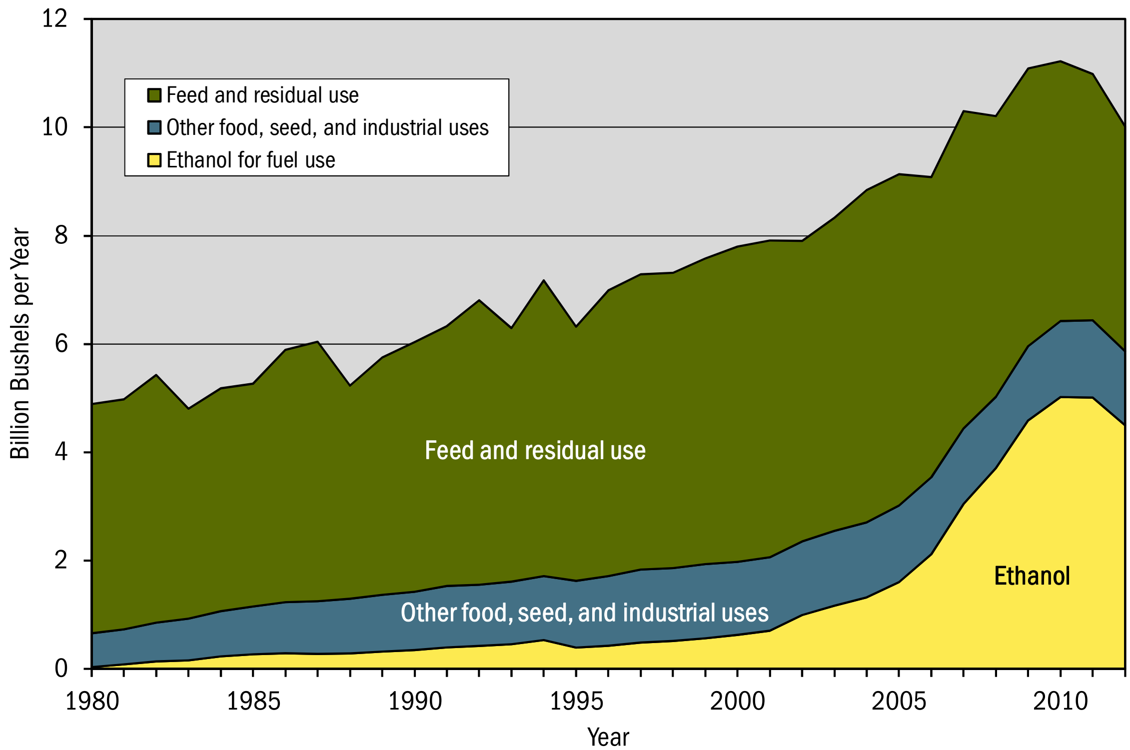

Figure 99. Disposition of U.S. corn crop for ethanol and other uses, 1980-2012.[232]

The decline in 2012 corn production is in large part related to the severe drought that covered much of the U.S.

One of the major criticisms of corn ethanol is the use of a food crop for fuel, resulting in increased food prices and possibly food shortages, as well as the displacement of other food crops. Albino et al. point out that the ethanol in a gallon of E10 gasoline (10 percent ethanol), contains enough food energy to feed one person for 1.4 days.[233] They also point out that *"the total amount of ethanol produced in the U.S. in 2011 was 13.95 billion gallons, enough to feed 570 million people in that year."*

[231] K. Drum, "Ethanol Subsidies: Not Gone, Just Hidden a Little Better", January 5, 2012, *Mother Jones*, http://www.motherjones.com/kevin-drum/2012/01/ethanol-subsidies-not-gone-just-hidden-little-better.

[232] Data from U.S. Department of Agriculture, "Corn Use Table", 2012, http://www.ers.usda.gov/media/866543/cornusetable.html.

[233] D.K. Albino, et al., "Food for Fuel: the Price of Ethanol", New England Complex Systems Institute, 2012, http://necsi.edu/research/social/foodprices/foodforfuel/foodforfuel.pdf.

Perhaps the most damning criticism of corn ethanol is its low net energy return (EROEI). Murphy et al. have calculated an EROEI of 1.07:1, with a possible error range of from 0.87:1 to 1.27:1.[234] Others suggest it is as low as 0.82:1 or as high as 1.73:1.[235] Murphy et al. recognize that the EROEI is likely to vary between regions with high potential for growing corn and more marginal areas. Due to the subsidies and incentives to grow corn imposed by the federal government, it is likely that ever more marginal areas have been converted to corn reducing the overall net energy return. Indeed Murphy et al. point out that "*production of corn ethanol within the United States is unsustainable and requires subsidies from the larger oil economy.*"

There are similar issues with other food crops—such as soy beans, sugarcane and palm oil—displacing both food for humans and, in the case of sugarcane and palm oil, virgin tropical ecosystems.[236] The EROEI of these sources is somewhat higher than corn ethanol. Sugarcane, for example, including the use of stalks burned for heat in the process, may be as high as 8:1. Others suggest the EROEI is no higher than 2.7:1 to 3:1.[237]

Although pilot plants have been producing small amounts of cellulosic ethanol for some time, commercial production does not exist. Iogen, one of the leading cellulosic ethanol proponents, has operated a pilot project in Ottawa for the past eight years which produces about five barrels per day.[238] A joint project with Shell to build a commercial scale plant in Manitoba was recently cancelled.[239] Although President Bush in 2007 mandated the use of 500 million gallons of cellulosic ethanol by 2012, and subsidies of $1.5 billion were applied, the 2012 limit has since been revised downward to less than 12 million gallons (783 barrels per day).[240]

Commercialization of algae biofuels has similarly not materialized despite decades of research and hundreds of millions of dollars in expenditures. Although algae holds considerable promise, given that it can produce much higher amounts of biomass per unit area and does not displace food crops, its commercialization has proven elusive.[241] A recent study by the National Research Council suggests large-scale production of algae biofuels is unsustainable with existing technology.[242]

Biofuels have the ability to contribute perhaps as much as 10 percent of current U.S. petroleum liquids consumption. They clearly have their own set of environmental impacts on water, soils and ecosystems and may have only limited impact in reducing greenhouse gas emissions given their generally low net energy return.

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[234] D.J. Murphy, et al., "New perspectives on the energy return on (energy) investment (EROI) of corn ethanol", *Environ Dev Sustain* 13:179-202, 2011, http://www.springerlink.com/content/j458318434015735/fulltext.pdf.

[235] C.J. Hall, "Seeking to Understand the Reasons for Different Energy Return on Investment (EROI) Estimates for Biofuels", *Sustainability* 3(12), 2413-2432, 2011; doi:10.3390/su3122413.

[236] T. Knudson, "The Cost of the Biofuel Boom: Destroying Indonesia's Forests", Yale Environment 360, January 19, 2009, http://e360.yale.edu/feature/the_cost_of_the_biofuel_boom_destroying_indonesias_forests/2112/.

[237] David Fridley, Lawrence Berkeley National Laboratory, personal communication, December, 2012.

[238] Iogen Corporation, "Demo Plant Production", 2012, http://www.iogen.ca/index.html

[239] S. McCarthy, "Shell-Iogen plant cancellation raises doubts about new biofuel technology", *Globe and Mail*, April 30, 2012, http://www.theglobeandmail.com/report-on-business/industry-news/energy-and-resources/shell-iogen-plant-cancellation-raises-doubts-about-new-biofuel-technology/article4103858/.

[240] *The Wall Street Journal*, "The Cellulosic Ethanol Debacle", December 14, 2011, http://online.wsj.com/article/SB10001424052970204012004577072470158115782.html

[241] Oilprice.com, "Why are we not drowning in algae biofuel?", October 16, 2012, http://oilprice.com/Alternative-Energy/Biofuels/Why-are-we-not-Drowning-in-Algae-Biofuel.html

[242] Committee on the Sustainable Development of Algal Biofuels, "Sustainable Development of Algal Biofuels in the United States", National Research Council of the National Academies, October 2012, http://download.nap.edu/cart/download.cgi?&record_id=13437&free=1.

Coal- and Gas-to-Liquids

Conversion of coal to liquid fuels using the Fischer-Tropsch process has been used for decades in South Africa and to a lesser degree elsewhere. More recently, gas-to-liquids plants have been constructed in Qatar and are proposed in the U.S. The conversion of both fuels to liquids suffers from several intrinsic problems:

- the infrastructure is very expensive.
- the process is very energy intensive and produces disproportionate amounts of CO_2.
- the process is uneconomic unless gas and coal prices are very low relative to oil.

Exxon Mobil expressed some of these issues recently on gas-to-liquids:[243]

> *"The reason you see so few [gas-to-liquids] plants is the economics are challenged at best," said William M. Colton, Exxon Mobil's vice president of corporate strategic planning. "We do not see it being a relevant source of fuels over the next 20 years."*

For a gas-to-liquids plant recently completed in Qatar, Shell spent approximately $136,000 per barrel-per-day of capacity (i.e., $19 billion for a capacity of 140,000 bpd)—considerably higher than a tar sands plant with an upgrader typically costing about $100,000 per barrel-per-day of capacity.

From a CO_2 emissions perspective, the Natural Resources Defense Council (NRDC) reports that liquids derived from coal have twice the "well-to-wheels" emissions of gasoline.[244] Bartis et al. point out the infeasibility of scaling up coal-to-liquids (CTL) production: "*CTL development at a scale of three million bpd by 2030 would require about 550 million tons of coal production annually.*"[245] This would require scaling up coal mining in the U.S. by 50 percent. The collateral environmental impacts of coal mining are well known, and scaling by anywhere near this amount is likely impossible from logistical and reserve-availability standpoints. And, even if it were possible, 3 mbd is not that significant in the face of total consumption.

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243 John Broder and Clifford Krauss, "Big, and Risky, Energy Bet", December 17, 2012, *New York Times*, http://www.nytimes.com/2012/12/18/business/energy-environment/sasol-betting-big-on-gas-to-liquid-plant-in-us.html.
244 Natural Resources Defense Council, "Why Liquid Coal Is Not a Viable Option to Move America Beyond Oil", 2011, http://www.nrdc.org/globalwarming/coal/liquids.pdf
245 Bartis, et al., "Producing Liquid Fuels from Coal: Prospects and Policy Issues", RAND Corporation, 2008, http://www.rand.org/content/dam/rand/pubs/monographs/2008/RAND_MG754.pdf.

The EIA has recently scaled back its projection for coal-to-liquids in the U.S. while at the same time scaling up its estimates of gas-to-liquids as illustrated in Figure 100. Its most recent projection calls for 0.26 mbd of combined coal- and gas-to-liquids by 2040. So despite the fact that coal and gas are purported to have vast in situ resources, this is a case of a severe "tap", or rate of supply, constraint on the "tank." It is unlikely that coal- or gas-to-liquids will be a significant supplier of liquid fuels in the foreseeable future.

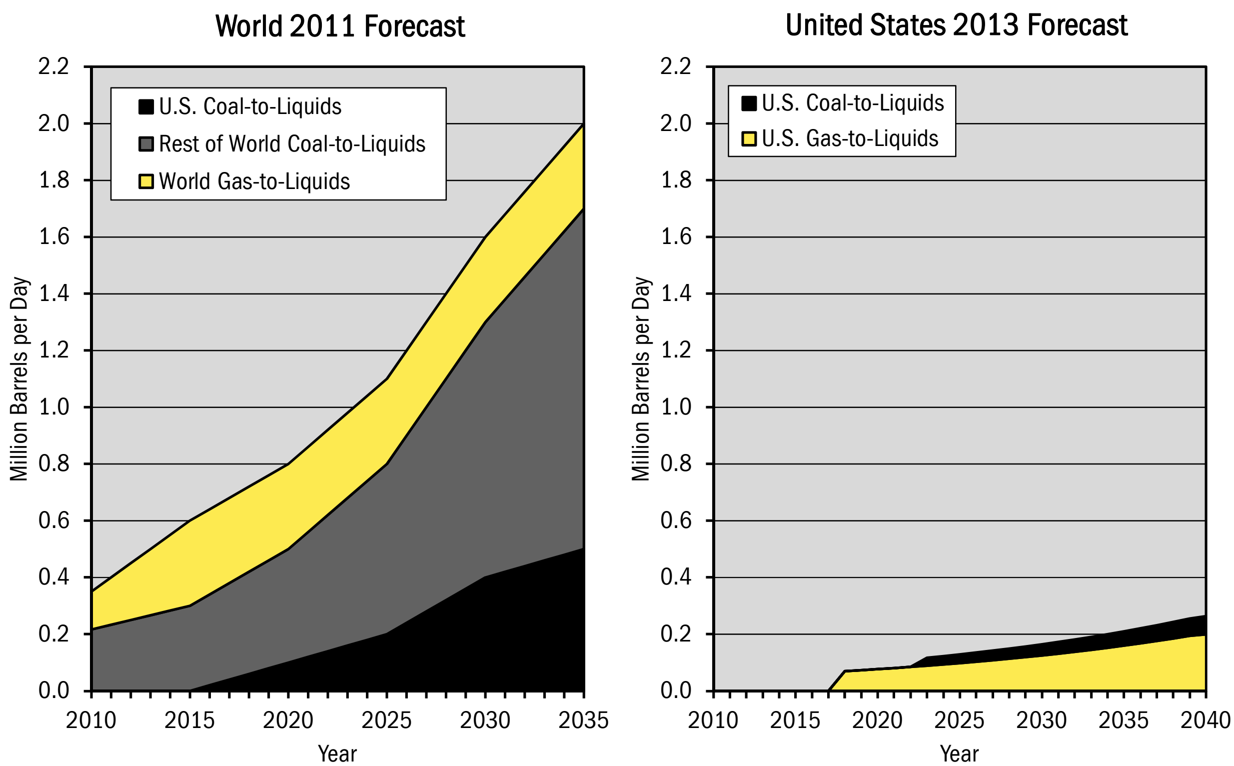

Figure 100. Projections of world and U.S. coal- and gas-to-liquids production, 2011 EIA forecast (left) compared to EIA 2013 U.S. forecast (right), 2010-2035.[246]

Coal-to-liquids production has been scaled back whereas gas-to-liquids production has increased for the U.S., but still is relatively insignificant in the face of projected consumption.

[246] Data from the EIA International Energy Outlook 2011, http://www.eia.gov/forecasts/ieo/ and the EIA Annual Energy Outlook 2013 early release.

Enhanced Oil Recovery

Enhanced oil recovery involves the injection of CO_2 to displace oil in exhausted or nearly exhausted oil fields. It has also been touted as a way to enhance coalbed methane production as CO_2 selectively displaces methane in coal (it also swells the coal, however, reducing permeability and thus limiting the ability to produce the methane). Perhaps the most widely known example is the Weyburn field of Saskatchewan,[247] although CO_2 injection has been used for decades for enhanced oil recovery in Texas and elsewhere. This may seem like a no-brainer—sequester CO_2 while recovering more oil—and in fact it is a niche source of oil, although the source of the CO_2 has more commonly been naturally occurring deposits than anthropogenic emissions. The Weyburn project is an exception, as the CO_2 used is obtained from the Great Plains Synfuels Plant near Beulah, North Dakota, and pipelined north to Canada.

Figure 101 illustrates the projection of the EIA in its 2012 and 2013 forecasts for CO_2 enhanced oil recovery. Rates of production are forecast to fall in the near term and then triple to 0.66 mbd by 2040. As with any oil and gas production project, significant investments in infrastructure are necessary to provide the CO_2 along with injection, monitoring and production wells. Long-term storage integrity is also a major concern, and has been questioned at the Weyburn project with allegations of leaking CO_2.[248] Enhanced oil recovery is highly unlikely to be more than a small contributor to future requirements.

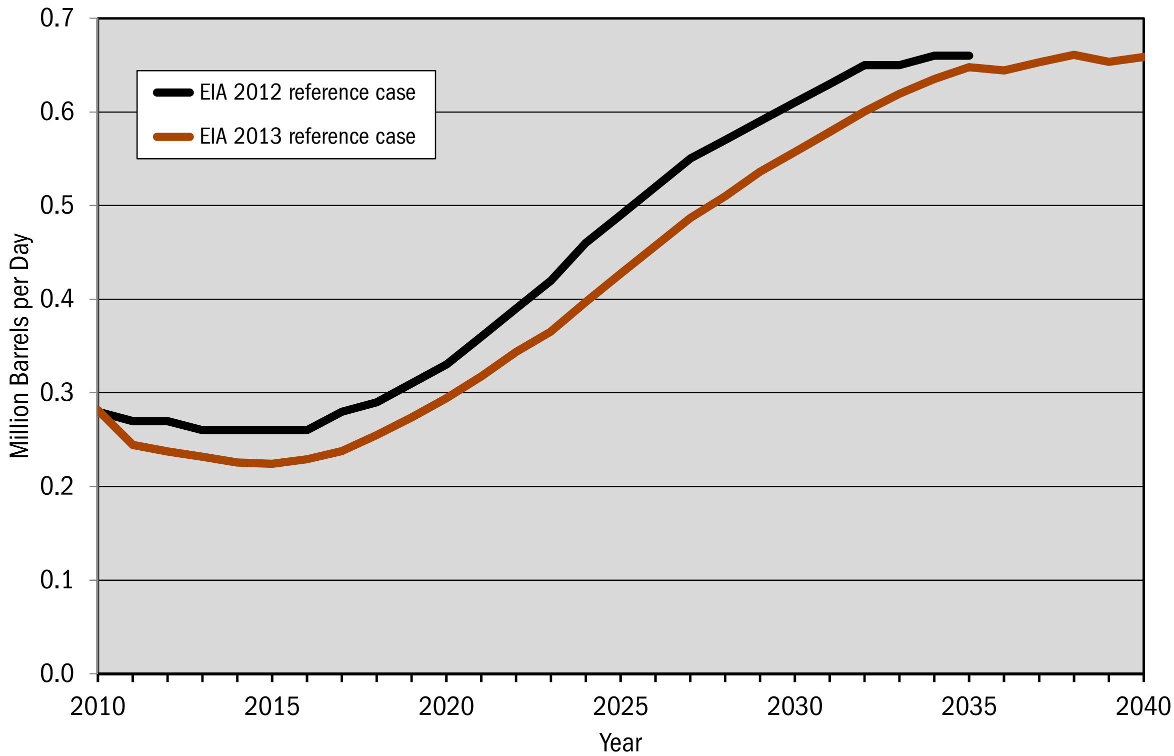

Figure 101. U.S. enhanced oil recovery production forecasts, 2010-2040 (EIA Reference Cases, 2012 and 2013).[249]

[247] Carbon Capture & Sequestration Technologies, "Weyburn Fact Sheet: Carbon Dioxide Capture and Storage Project", MIT Energy Initiative, Massachusetts Institute of Technology, December 5, 2012, http://sequestration.mit.edu/tools/projects/weyburn.html.
[248] Canadian Broadcasting Corporation, "Alleged leak of CO2 at Sask. farm to be probed", April 19, 2011, http://www.cbc.ca/news/technology/story/2011/04/19/tech-carbon-capture-weyburn-saskatchewa.html.
[249] Data from EIA Annual Energy Outlook 2013 early release, Table 14, and Annual Energy Outlook 2012, Table 14.

OTHER UNCONVENTIONAL GAS

KEY TAKEAWAYS

- **Coalbed methane** is and will continue to be a small player in total U.S. gas supply. Production has plateaued and reserves have fallen over the past five years. Given this the EIA's projection of flat to rising production and the consumption of nearly three times current proved reserves by 2040 seems unlikely.
- **Offshore gas** is projected to make up less than 10 percent of U.S. gas supply through 2040. Notwithstanding the significant undiscovered potential, it is difficult gas that will remain constrained by the "tap" more than the "tank."
- **Gas hydrates** have extremely large in situ resources which have resisted any significant production. They will likely remain "*the fuel of the future that always will be.*" They are an extreme example of a rate-constrained resource with a very large "tank" and a "tap" that remains completely shut, despite decades of research at the expenditure of hundreds of millions of dollars.
- **In situ coal gasification** is a much hyped resource in some circles but so far has been relegated to a niche source at best, with no commercial production outside of Uzbekistan, where it has purportedly fueled an onsite power plant for decades.
- **Biogas** from municipal landfills is capturing and utilizing methane, which is a potent greenhouse gas, that would otherwise be vented into the atmosphere. Although it is a small niche player in terms of total supply, it provides important environmental benefits. Household-scale biogas production is also utilized in developing nations. Large-scale centralized biogas production from food crops as currently conducted in Germany is more controversial.

Coalbed Methane

Coalbed methane is ubiquitous in the widespread coalfields of the United States; however, geological conditions with sufficient gas content and permeability to allow commercial production are more rare. Figure 102 illustrates the distribution of coal basins and regions of coalbed methane production in the U.S.

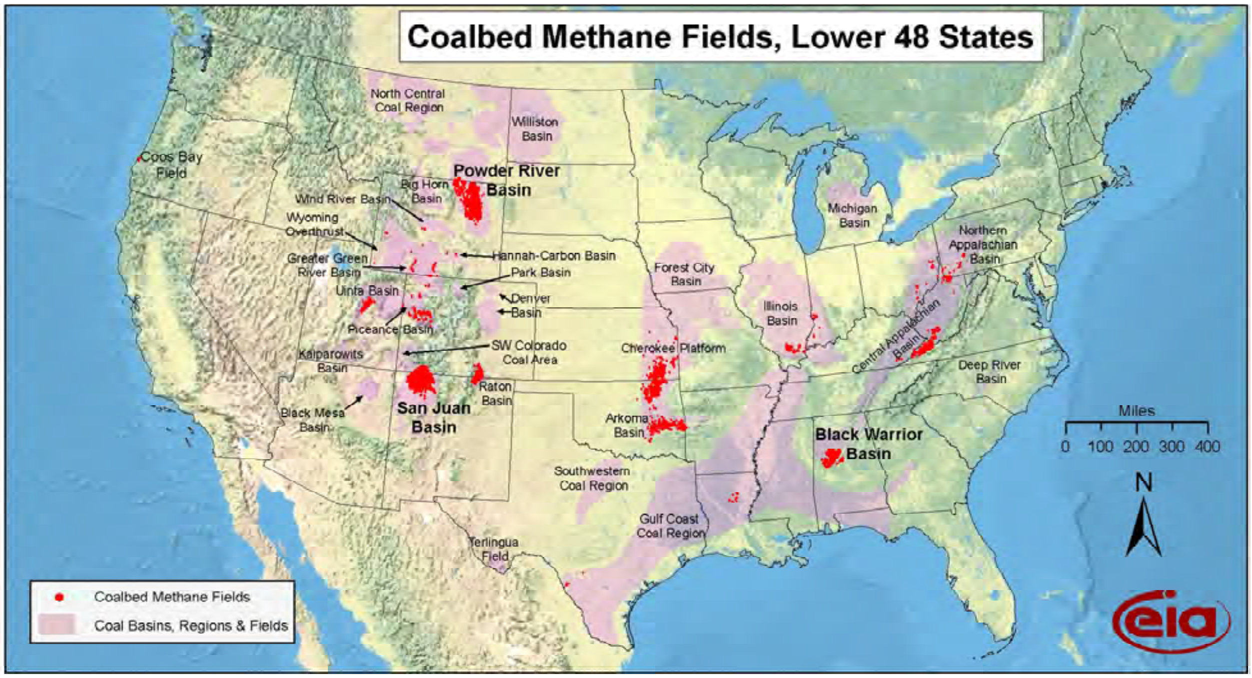

Figure 102. Distribution of coalbed methane fields and coal basins in the U.S.[250]

The San Juan Basin of Colorado and New Mexico was the first field developed and is still by far the largest producer.

At one point in the early 1990's coalbed methane was viewed as a budding panacea for U.S. gas supplies, similar to what shale gas is purported to be now. Subsequent exploration and development work revealed that such expectations were unwarranted. Figure 103 illustrates coalbed methane production in the U.S. by region. Coalbed methane is now about eight percent of U.S. gas production and has been falling from a recent peak in 2008. Fully half of production comes from Colorado and New Mexico, mainly from the San Juan Basin, which was the first coalbed methane field developed and is still the largest producer. Thirty percent of the remainder comes from the Powder River Basin of Wyoming, which has unique low-rank but high-permeability coal seams. The balance comes from numerous other basins.

[250] Map from the EIA, updated April 8, 2009, http://www.eia.gov/oil_gas/rpd/coalbed_gas.jpg.

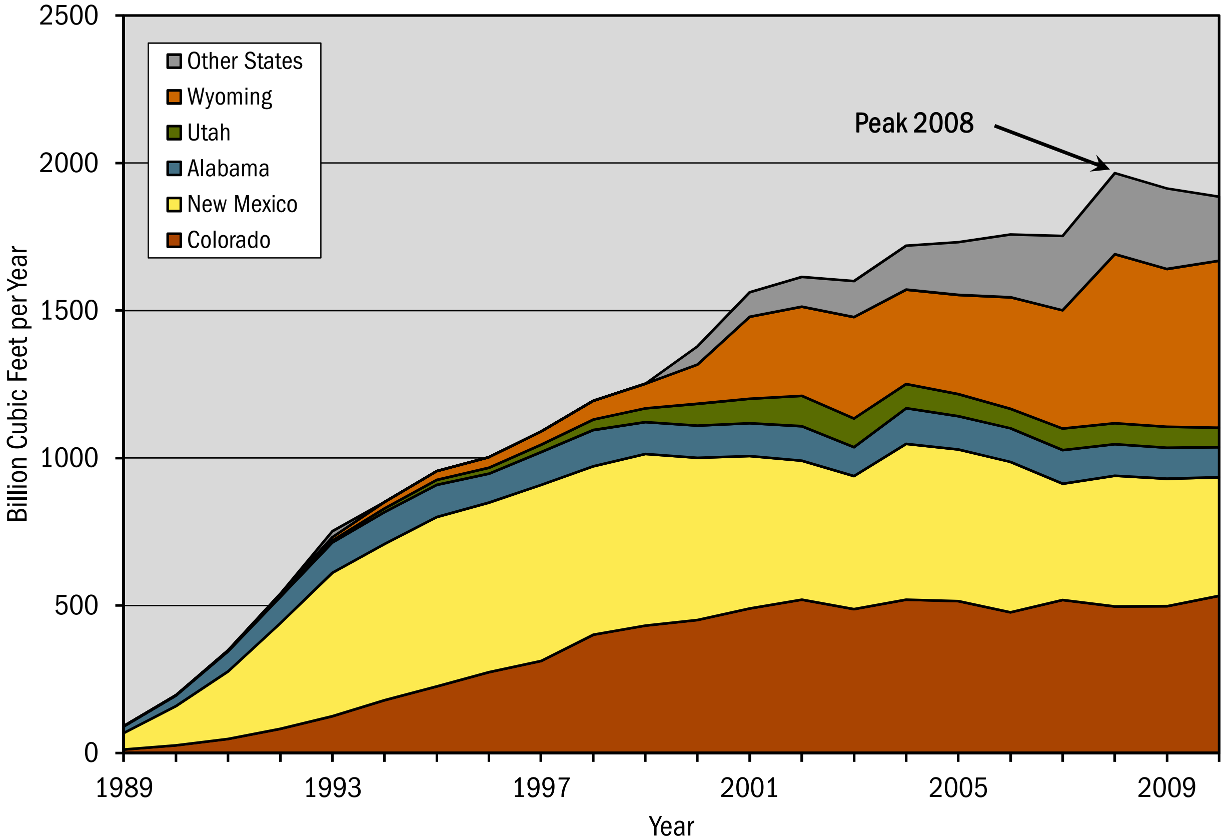

Figure 103. U.S. coalbed methane production by state, 1989-2010.[251]
Coalbed methane is currently about 8 percent of U.S. gas production.

Coalbed methane is generated as part of the coalification process as organic matter is converted to coal through burial over millions of years and exposure to heat and pressure. The methane is adsorbed to the coal (i.e., the methane molecules adhere to surface of the coal) and held there under pressure. Typically the first phase of developing a coalbed methane well is the production of the formation water, sometimes for a year or more, to dewater the coal and reduce pressure so that the adsorbed methane is freed and can migrate to the well bore. Natural permeability is very important and is often enhanced with hydraulic fracturing or cavitation. The production and disposal of large amounts of formation water can be problematic and has led to strong public opposition to coalbed methane in some areas. Unlike the rapid production declines observed in shale gas wells, coalbed methane wells, once dewatered, can produce with relatively low decline rates for many years. Early production of coalbed methane was assisted by a Section 29 tax credit that expired in 1992.[252]

251 Data from the EIA, "Coalbed Methane Production," August 2, 2012, http://www.eia.gov/dnav/ng/xls/NG_PROD_COALBED_S1_A.xls.
252 EIA, "Coalbed Methane Basics," undated,, http://www.eia.gov/emeu/finance/sptopics/majors/coalbox.html.

In the 21 years since significant coalbed methane production was initiated, 27 tcf has been produced. The latest projection of the EIA is that another 52 tcf can be recovered in the 29 years from 2011 to 2040. This is an extremely aggressive forecast that defies the geological realities. Current coalbed methane reserves are 17.5 tcf, having fallen from 21.9 tcf in 2007; in other words, production has not been replaced with new reserve additions. Yet the EIA is projecting that nearly three times the current reserves will be produced and consumed by 2040. Coalbed methane reserves by state compared to the EIA production forecast are illustrated in Figure 104.

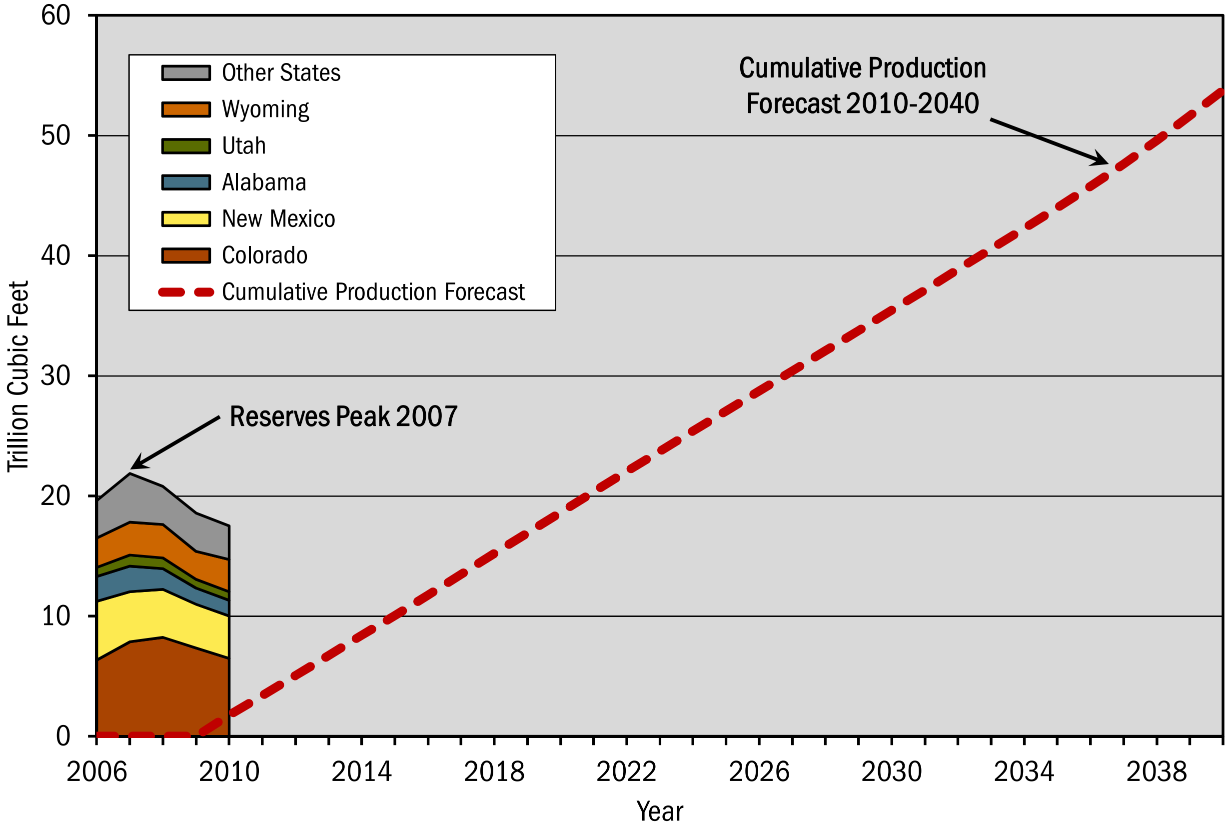

Figure 104. U.S. coalbed methane reserves by state (2006-2010) compared to production forecast through 2040 (EIA, 2013).[253]

This is an extremely aggressive forecast in that nearly three times current proved reserves are projected to be produced by 2040.

Coalbed methane will continue to be a small player in total U.S. gas supply. Given that production has been falling over the past three years, the EIA's projection of flat to rising production and the consumption of nearly three times current proved reserves by 2040 seems unlikely. Coalbed methane is an example of a resource with a very large "tank," if one considers all of the methane in situ in deep coal seams in the U.S., but with a limited and closing "tap", if one looks at the geological realities of what can likely be produced.

[253] Reserves from EIA, 2012, http://www.eia.gov/naturalgas/crudeoilreserves/excel/table_15.xls and projection is from EIA Annual Energy Outlook 2013 early release.

Arctic/Deepwater Gas

Although technically not unconventional gas (it is included in the IEA estimates of conventional gas), the deepwater and the Arctic are unconventional locales demanding the latest in drilling and production technologies. The U.S. Bureau of Ocean Energy Management (BOEM) has produced a new assessment of undiscovered technically recoverable oil and gas resources for the outer continental shelf areas illustrated in Figure 91.[254]

As with crude oil, the Gulf of Mexico has by far the highest potential in terms of gas reserves and undiscovered technically recoverable resources, as illustrated by Figure 105. Although there have been moratoriums in place to prevent exploitation of the Atlantic, most of the Pacific, and the eastern Gulf of Mexico, these regions collectively comprise only 14 percent of the total estimated undiscovered technically recoverable resources. For example, the mean undiscovered technically recoverable estimate of 31.3 tcf for the entire Atlantic coast, if it could be recovered, would supply the U.S. for 15 months. The Pacific coast north of southern California, where the current bans are in place, holds 16.1 tcf—which would last the U.S. 8 months.

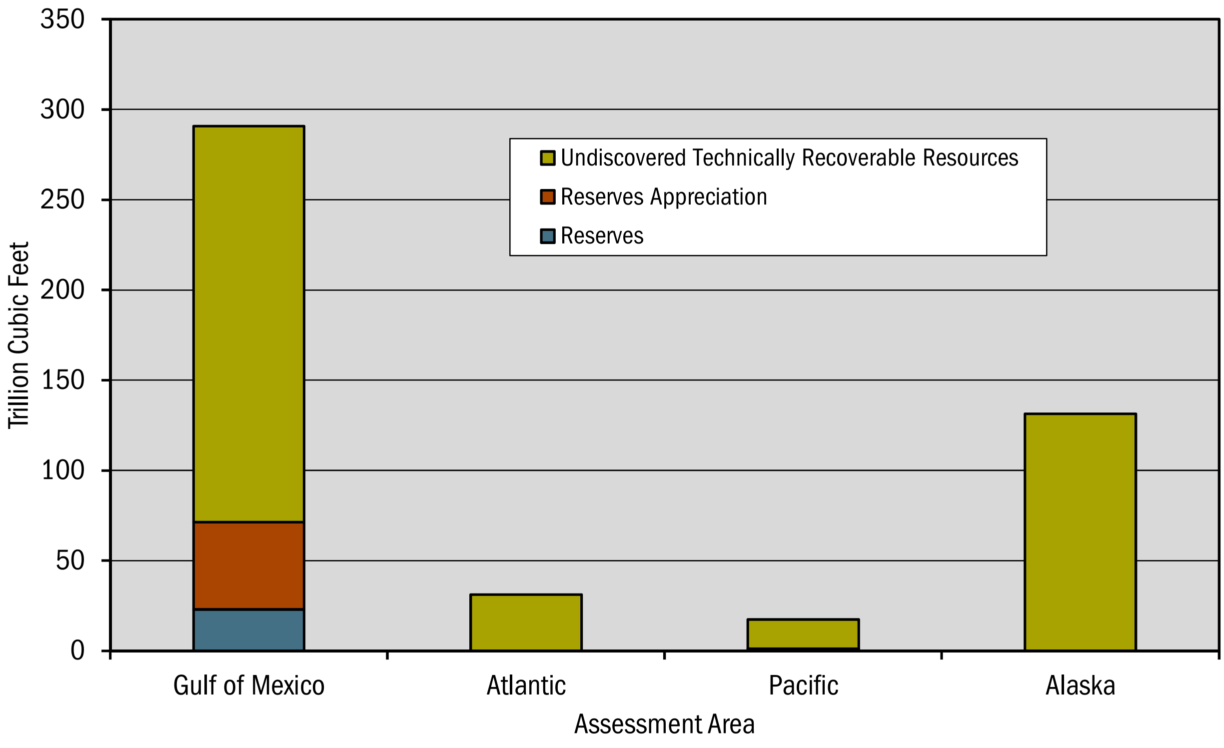

Figure 105. Remaining reserves and undiscovered technically recoverable gas resources in the U.S. outer continental shelves (BOEM, 2012).[255]

Note that "Reserves Appreciation" refers to estimates which are not necessarily proved.

[254] U.S. Bureau of Ocean Energy Management, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011", http://www.boem.gov/Oil-and-Gas-Energy-Program/Resource-Evaluation/Resource-Assessment/2011-RA-Assessments.aspx.
[255] U.S. Bureau of Ocean Energy Management, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011."

Of the total remaining resources in Figure 105, less than four percent are actually proved reserves. The balance are probabilistic estimates based on limited input data. BOEM estimated the potential recovery costs of the undiscovered technically recoverable gas resources (Figure 106). It suggests that 253 tcf, or 64 percent of the total, could be extracted at a cost of $6.41 per mcf or less, which is the maximum price the EIA foresees by 2035. This would require lifting the moratoriums on all coasts, developing all outer continental shelves and accepting the environmental risks which were the reason that the moratoriums were imposed in the first place. It would also mean developing the Chukchi and Beaufort Seas in the Arctic which contain 88 percent of Alaska's offshore gas potential.

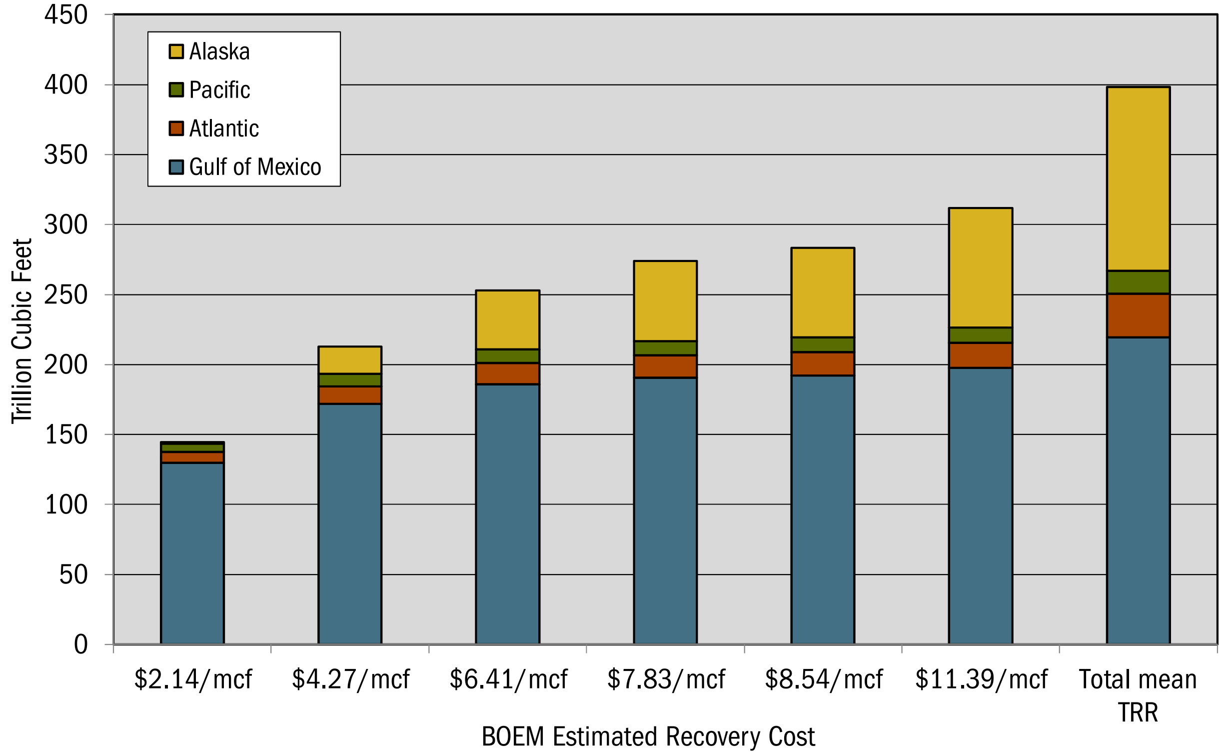

Figure 106. Estimated recovery cost of undiscovered technically recoverable gas resources in the U.S. outer continental shelves (BOEM, 2012).[256]

[256] U.S. Bureau of Ocean Energy Management, "Assessment of Undiscovered Technically Recoverable Oil and Gas Resources of the Nation's Outer Continental Shelf, 2011."

As with deepwater oil, deepwater gas exploration and production is very expensive. Wells cost $100 million or more, and ultra-deepwater rigs rent at $600,000 to $700,000 per day.[257] Despite the optimism of the EIA for maintaining and slightly increasing gas production in the offshore Gulf of Mexico through 2040 (Figure 32), production has been trending steadily downward (Figure 18), to where it is now 70 percent below 1998 levels. Given these trends, the EIA's optimism seems hardly warranted.

Deepwater gas production is less of an environmental threat that oil given that it dissipates quickly. Much of the offshore Gulf of Mexico production is, however, produced in association with oil, hence the inherent risks spectacularly highlighted with the BP Macondo spill in 2010 may still be evident for wells producing both gas and oil.[258] Such risks are impossible to reduce to zero given the harsh and unpredictable environments being explored.

Arctic offshore exploration adds another layer of risk as it is conducted in frigid, ice-choked waters. Unpredictable ice movements and icebergs pose a threat to rigs unlike anything experienced further south. Shell experienced some of these challenges when it attempted to initiate drilling in the Chukchi Sea in September, 2012.[259]

Offshore gas is projected to make up less than 10 percent of U.S. gas supply through 2040. Notwithstanding the significant undiscovered potential, it is difficult gas that will remained constrained by the "tap" more than the "tank." Opening up coastal areas currently under moratoriums would expand access to relatively minor additional resources, compared to the Gulf of Mexico, while posing environmental risks to much broader coastal regions. Arctic offshore gas production is unlikely to be more than a niche supply for the foreseeable future.

[257] David Welhe, "Transocean Biggest Winner From 28% Jump in Oil Rig Rates: Energy", Bloomberg, March 28, 2012, http://www.bloomberg.com/news/2012-03-27/transocean-biggest-winner-from-28-jump-in-oil-rig-rates-energy.html.
[258] C. Krauss and J. Schwartz, "BP Will Plead Guilty and Pay Over $4 Billion", *The New York Times*, November 14, 2012, http://www.nytimes.com/2012/11/16/business/global/16iht-bp16.html.
[259] J.M. Broder, "Shell Halts Arctic Drilling Right After It Began", *The New York Times*, September 10, 2012, http://green.blogs.nytimes.com/2012/09/10/shell-halts-arctic-drilling-right-after-it-began/.

Gas Hydrates

Gas hydrates, also known as methane clathrates, occur in regions of permafrost and in marine seafloor sediments when water and natural gas combine at low temperatures and high pressures to make an ice-like solid substance. They are very widespread and some estimates of in situ resources are astronomical, (exceeding 4 million tcf by some estimates[260]), yet meaningless from a supply point of view. Despite hundreds of millions of dollars spent on research, most notably by Canada, the U.S. and Japan, there is no commercial production. Avenues for production include changing the gas hydrate stability conditions by heating, depressurization, and injection of an "inhibitor." The most economical of these appears to be depressurization.[261]

Like any hydrocarbon resource, gas hydrates occupy a pyramid of resource quality (Figure 107).

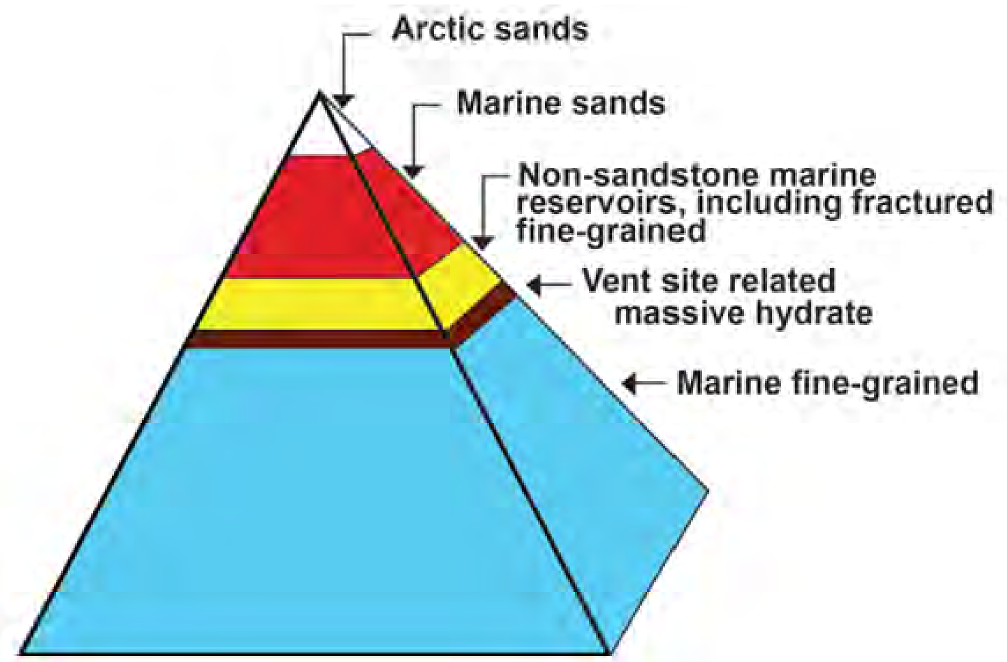

Figure 107. Gas hydrate resource pyramid illustrating the relative volumes of different rock types.

The rock types with the most potential are at the top of the pyramid. Although there has been no commercial production of gas hydrates anywhere in the world, the more permeable sandy lithologies at the top of the pyramid, particularly in conjunction with underlying conventional gas reservoirs, have the most promise for viable production.[262]

Research suggests that prospects for production are most likely for gas hydrates that are associated with underlying conventional gas deposits and which occur in sandy sediments.[263] The most likely candidates for commercial production are the Arctic sands and sandy marine deposits at the top of the pyramid, notwithstanding the fact that trying to produce gas hydrates from such deposits compounds

[260] Expert Panel on Gas Hydrates, "Energy from Gas Hydrates: Assessing the Opportunities and Challenges for Canada", Council of Canadian Academies, 2008, see Table 3.1, http://www.scienceadvice.ca/en/assessments/completed/gas-hydrates.aspx.
[261] Ibid, page 10.
[262] C. Ruppel, et al., "A New Global Gas Hydrate Drilling Map Based on Reservoir Type", National Energy and Technology Laboratory, 2011, *Methane Fire in the Ice* 11:1, 2011, http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/MHNews_2011_05.pdf#page=13.
[263] Expert Panel on Gas Hydrates, "Energy from Gas Hydrates: Assessing the Opportunities and Challenges for Canada".

the aforementioned environmental and economic issues for Arctic and offshore conventional gas resources. Gas hydrate deposits overlying conventional gas pools are likely to be an extremely small proportion of the total purported resource, and as yet have seen no commercial production.

Figure 108 illustrates one estimate of the volume of methane hydrates in sandy sediments which have the best prospects for production. At more than 43,000 tcf worldwide, this estimate is very large (but one hundredth of the largest numbers). Commercial production of significant volumes of gas from even the highest probability sediments is decades away, if ever.

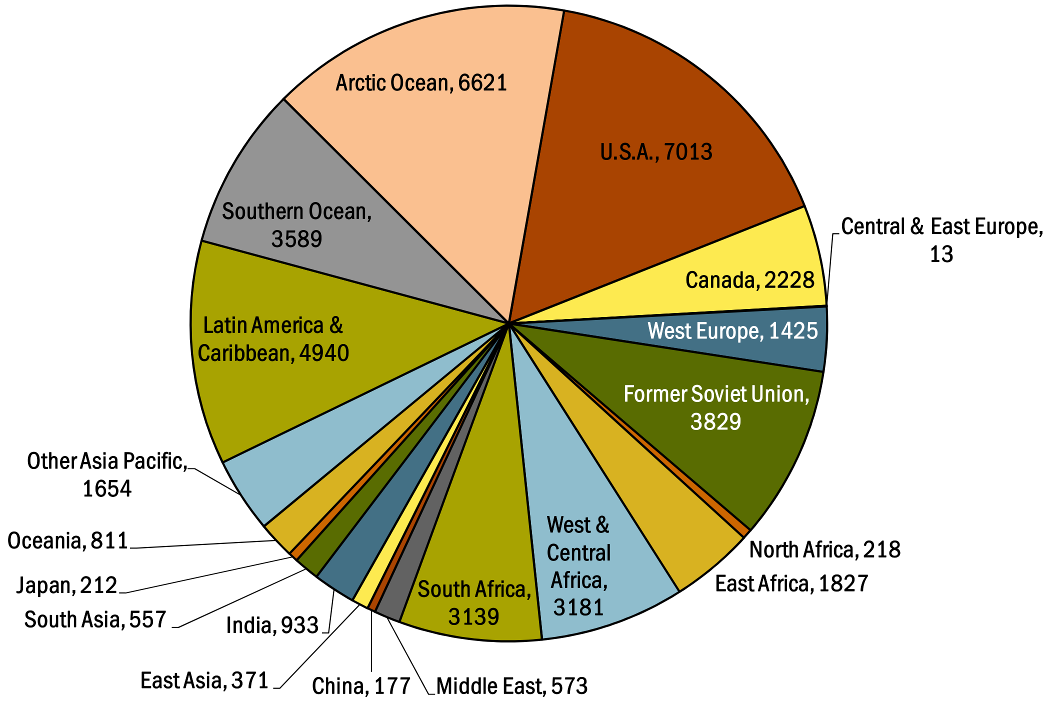

Figure 108. Median estimates of world in situ gas hydrate resources by region (tcf).[264]

Total estimate=43,311 tcf. These are estimates of the in situ volume of gas hydrates within sandy sediments, which have the most promise of successful production.

One of the most extensive production tests of gas hydrates was conducted in the Mackenzie Delta of the Canadian Arctic at the Mallik site. This project utilized depressurization to destabilize the reservoir and produced an average of 76 mcf/d over the six-day test.[265] No further work has been conducted at the site since it was abandoned in 2008. The Mallik project was located onshore in a relatively accessible location. Although it produced gas there is no indication of well life or basic economics, which speaks to the immense challenges of trying to produce gas hydrates in more remote arctic- and offshore-locations.

Gas hydrates will likely remain "*the fuel of the future that always will be.*" They are an extreme example of a rate-constrained resource with a very large "tank" and a "tap" that remains completely shut, despite decades of research at the expenditure of hundreds of millions of dollars.

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[264] Arthur H. Johnson, 2011, "Global Resource Potential of Gas Hydrate – A New Calculation", National Energy and Technology Laboratory, *Methane Fire in the Ice*, 11:2, 2011, http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/MHNews-2011-12.pdf#Page=1.

[265] Koji Yamamoto and Scott Dallimore, "Aurora-JOGMEC-NRCan Mallik 2006-2008 Gas Hydrate Research Project Progress", National Energy Technology Laboratory, *Fire in the Ice* 8:3, 2008, http://www.netl.doe.gov/technologies/oil-gas/publications/Hydrates/Newsletter/HMNewsSummer08.pdf#Page=1.

In Situ Coal Gasification

In situ or underground coal gasification (UCG) attempts to gasify coal seams that are too deep for surface mining and have not yet been, or are unsuitable for, underground mining. This is potentially a huge resource and efforts to develop UCG have been underway for more than a century. Much of the early work was conducted in the former Soviet Union (FSU) with five industrial scale projects reported to have been operating in the 1960's. The only commercial scale UCG project left in the world, which has reportedly been operating for 50 years, is located in Angren, Uzbekistan, and produces a low-heating-value syngas (primarily H_2 and CO) for an onsite power plant.[266]

Outside of the FSU a number of pilot projects were conducted in the U.S. and in Western Europe, mainly in the 1970's and 1980's. One of the largest in recent years is the Chinchilla project located in Queensland, Australia, which operated from 1999 to 2003 and gasified 35,000 tons of coal. In total, considering the 50,000 tons of coal gasified during the U.S. pilot projects, 85,000 tons of coal have been gasified via UCG outside of the FSU over four decades. By comparison, the U.S. produced and consumed nearly a billion tons of coal in 2011 alone.

Although there are many proposals and early-stage UCG projects scattered around the world, including in Canada and the U.S., a review of the websites of several promoters of UCG reveals that none of these have proceeded to fruition as large-scale commercial projects. Typically they are announced with great fanfare and then fade from existence. Lawrence Livermore National Laboratory (LLNL), whose scientists worked on some of the early U.S. UCG pilot projects, became a consultant to a group attempting to initiate a commercial UCG project in Alaska (Cook Inlet Region Incorporated). LLNL does not consider UCG a commercial technology, and proposed a four-year, $120 million program to address limiting issues, some of which include: [267,268]

- Lack of process monitoring
- Best gasification design unclear
- Variable syngas quality
- Difficulty controlling in situ cavity growth
- Commercial viability of CO_2 disposal given the large quantities produced
- Environmental issues including groundwater contamination and subsidence

These problems and the lack of widespread commercial viability of UCG, despite decades of attempts, make it a niche player at best in terms of future gas supply. UCG is yet another example of a rate-constrained resource with a potentially very large tank but a very limited tap.

[266] Evgeny Shafirovich, Maria Mastalerz, John Rupp, and Arvind Varma, "Phase I Report to the Indiana Center for Coal Technology Research (CCTR)", Purdue University, August 31, 2008, http://www.purdue.edu/discoverypark/energy/assets/pdfs/cctr/researchReports/UCG-Phase1-08-31-08.pdf.
[267] Bill Powers, "Technical and Cost Issues Associated with CIRI Underground Coal Gasification Project", Powers Engineering, February 23, 2010, http://www.groundtruthtrekking.org/Documents/UCG/Powers%20Egr_CIRI%20UCG_feasibility_cost_report.pdf.
[268] Julio Friedmann, "Accelerating Development of Underground Coal Gasification: Priorities and Challenges for U.S. Research and Development", Chapter 1 in *Coal Without Carbon: An Investment Plan for Federal Action*, Clean Air Task Force Report, 2009, http://www.catf.us/resources/publications/files/Coal_Without_Carbon.pdf.

Biogas

Biogas is gas generated from the gasification of organic wastes from agriculture or from municipal landfills (landfill gas). Its use has been expanding rapidly in the developing world and in Europe as well as increasingly in North America.

The U.S. Environmental Protection Agency (EPA) estimates that there are now 560 landfill gas projects in the U.S. with the potential for an additional 510 projects.[269] These projects produce a low-Btu-content gas (50 percent methane and 50 percent CO_2) that can be used for heating and electricity generation in much the same way as conventional gas. Given that methane is a much more potent greenhouse gas than carbon dioxide, capturing and utilizing methane as opposed to venting it into the atmosphere greatly reduces this impact. Gas production from these projects currently amounts to 0.31 bcf/day, with an additional potential of 0.59 bcf/day if all projects are developed. Although this is very small compared to the total gas production of the U.S. it makes imminent sense: Methane is captured and utilized instead of vented, risks from landfill gas are eliminated, and the volume in landfills is reduced.

Biogas is also generated from agricultural and other organic wastes in small-scale distributed gasifiers at the individual farm and community levels, and in larger-scale and more centralized gasifiers. In the developing world, efforts are underway to install small-scale gasifiers to produce fuel for cooking and other uses from manure and organic wastes.[270] This displaces the need to use firewood for energy and therefore reduces ecological degradation. In developed countries, larger-scale biogas facilities are typically used to provide fuel for electricity generation. In Germany this practice is controversial, as the primary feedstock is corn and the resulting gas is heavily subsidized by Germany's Renewable Energy Act.[271] The situation is reminiscent of the U.S. subsidies on corn for ethanol: the subsidies in Germany have resulted in corn displacing other food crops, driven up prices and necessitated imports of grain and animal feed.

Biogas is thus a niche source of gas supply. In the right circumstances it can make sense as it can reduce greenhouse gas emissions and provide a fuel source to reduce other ecological impacts. However, it is not scalable to be able to offset a significant proportion of today's gas consumption, and attempts to scale it at the expense of food crops are counterproductive.

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269 Environmental Protection Agency, "Landfill Gas Energy", 2012, http://www.epa.gov/statelocalclimate/documents/pdf/landfill_methane_utilization.pdf.

270 Hivos, "Indonesia Domestic Biogas Programme", 2012, http://www.snvworld.org/sites/www.snvworld.org/files/publications/indonesia_domestic_biogas_programme_brochure.pdf.

271 Nils Klawitter, "Biogas Boom in Germany Leads to Modern-Day Land Grab," Spiegel Online International, August 30, 2012, http://www.spiegel.de/international/germany/biogas-subsidies-in-germany-lead-to-modern-day-land-grab-a-852575.html

NON-GEOLOGICAL CONSIDERATIONS

ECONOMICS

Energy underpins all facets of modern society and the provision of food, transport, and the myriad natural resources that are inputs to the manufacture of the components of everyday life. Hydrocarbons (oil, gas and coal) currently provide over 80 percent of this energy but their reign of 160 years has been short-lived in the context of the evolutionary development of mankind. As pointed out in Figure 109, 90 percent of these hydrocarbons have been consumed in a mere 75 years since 1938, and half have been consumed since 1986. This amounts to 3,083 billion barrels of oil equivalent hydrocarbon energy burned since 1850.

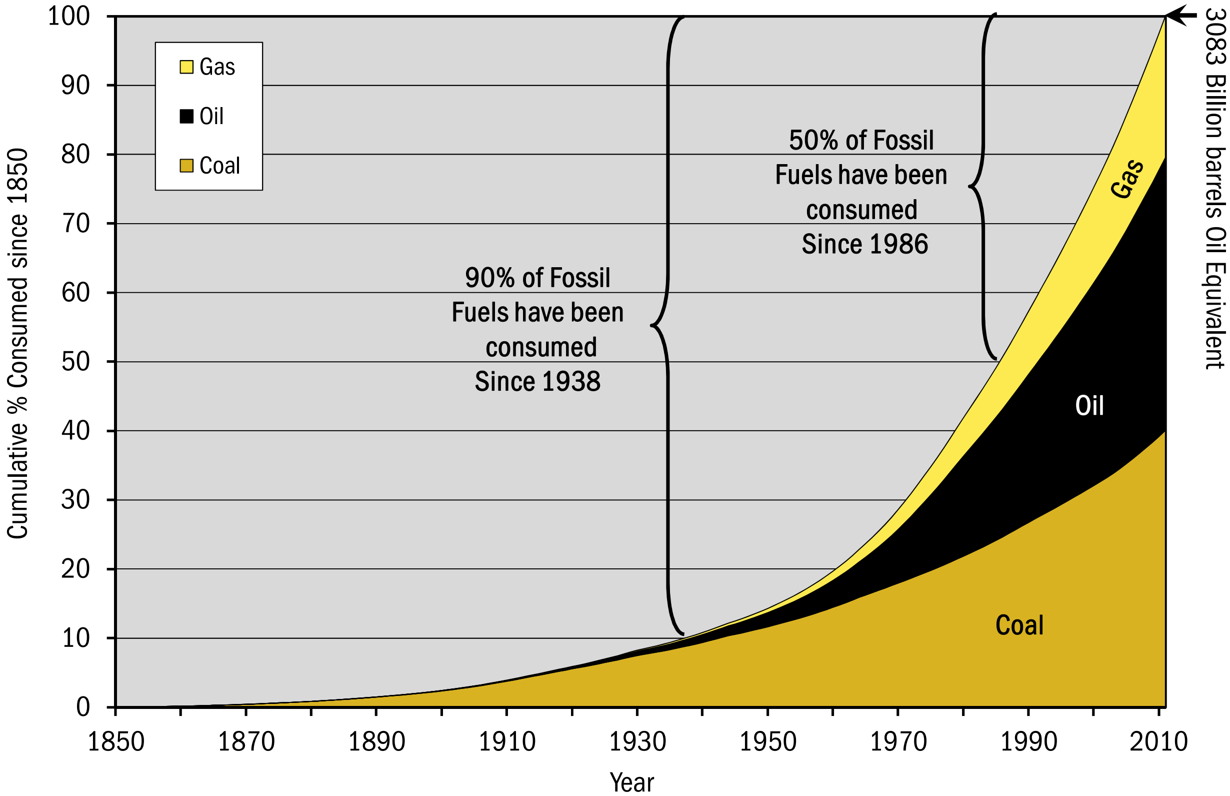

Figure 109. Cumulative world consumption of oil, gas and coal since 1850.[272]

A total of 3,083 billion barrels oil equivalent of hydrocarbon energy have been consumed as of year-end 2011.

The EIA's most recent reference case projection for the world requires a 47 percent increase in total energy consumption over 2010 levels by 2035, at which point hydrocarbons would still make up 79 percent of energy consumption.[273] This translates to the consumption of 27 percent more oil, 48 percent more gas, and 45 percent more coal in 2035 compared to 2010. This would require the acquisition and consumption of 2,190 billion barrels of oil equivalent energy in terms of oil, gas, and coal in the 24 years between 2011 and 2035, an amount which equals 71 percent of all the hydrocarbons *ever consumed*.

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[272] Data from Arnulf Grubler, "Technology and Global Change: Data Appendix," 1998, http://www.iiasa.ac.at/~gruebler/Data/TechnologyAndGlobalChange/; BP, *Statistical Review of World Energy*, 2012.

[273] EIA International Energy Outlook 2011, Table A2, http://www.eia.gov/forecasts/ieo/excel/appa_tables.xls.

Given the IEA's projection of declining production of conventional crude oil through 2035 (Figure 22), and the review of potential supply from unconventional oil and gas sources conducted in this report, the EIA projection will be very difficult and likely impossible to achieve. At a minimum, future energy supply will mean higher and more volatile prices and, without adequate planning and foresight, could mean physical supply shortages. Energy prices are already at historically high levels and are increasingly tightly linked to the prices of other commodities that form the basic inputs to modern society (Figure 110). Energy and commodity prices are up 70 to 90 percent over 2005 levels despite the fact that the developed world economies are struggling with low rates of growth.

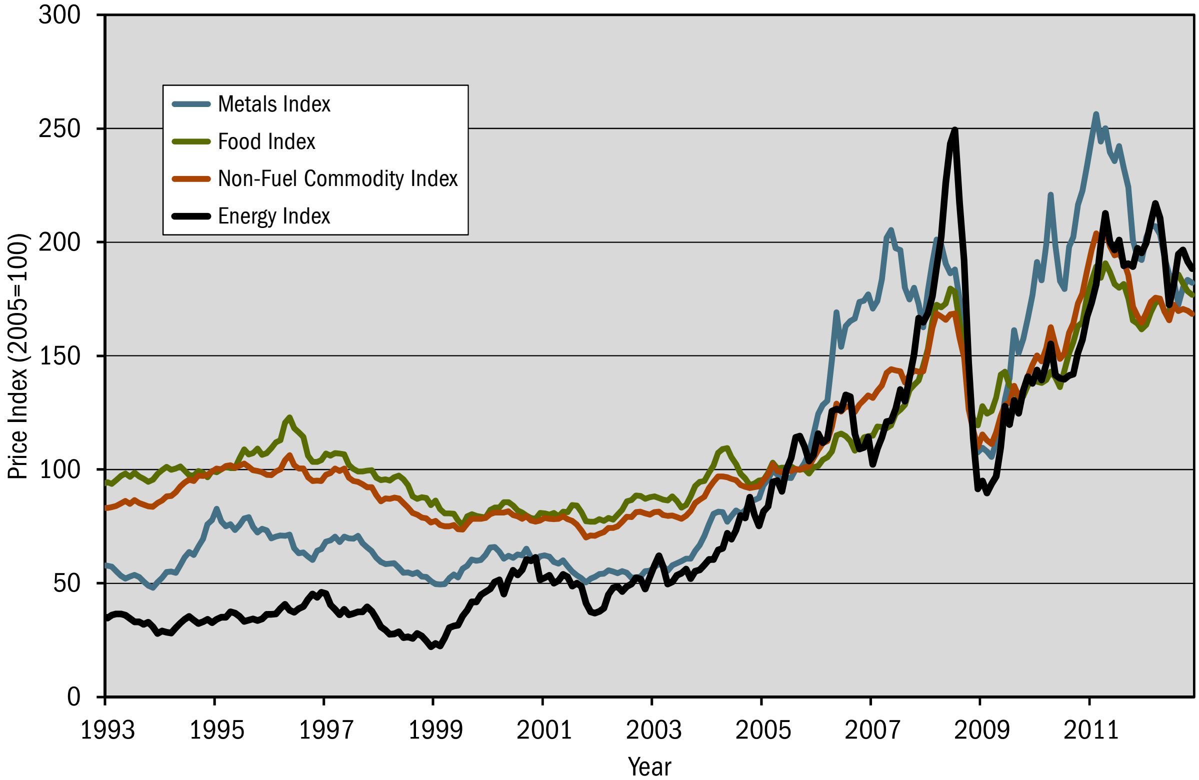

Figure 110. Price indices for energy, metals, food and non-food commodities, 1993-2012.

Prices of commodities have become increasingly correlated with the price of energy which forms a fundamental input into their supply.[274]

Some well-respected observers suggest that low- or zero-rates of growth will become a permanent condition.[275] Other observers point to looming shortfalls in the availability of basic commodities including water and arable land.[276] The lack of abundant cheap energy which allowed the rapid growth in supply of natural resource inputs and the exploitation of arable land and water over the past century is likely to be a step change unlike anything observed thus far in the evolution of industrial society. We ignore this at our peril, yet the projections from the EIA assume that U.S. GDP will rise at 2.5 percent per

[274] Price indices from the International Monetary Fund, via http://www.indexmundi.com/commodities/ (accessed January 2013).

[275] Jeremy Grantham, "On the Road to Zero Growth", *GMO Quarterly Letter*, November 2012, http://www.gmo.com/websitecontent/JG_LetterALL_11-12.pdf.

[276] Dambisa Moyo, "The Resource Shortage is Real", *Time*, June 8, 2012,.

year for the next 25 years and that unemployment will return to rates below 6 percent by 2018 and remain there through 2040.[277]

One of the reasons for the EIA's optimism is the improvement in "energy intensity" over time, which is the amount of energy consumed to produce a dollar of GDP. Figure 111 illustrates this trend over the past 45 years. Notwithstanding this improvement in energy intensity, growth in GDP is generally always accompanied by a growth in real energy consumption. World energy consumption more than tripled over the past 45 years while U.S. consumption grew by 76 percent. The EIA projects that improvement in U.S. energy intensity will continue, with 48 percent less energy required per dollar of GDP in 2040 compared to 2010—but also that overall energy consumption will increase by 9 percent over this period.

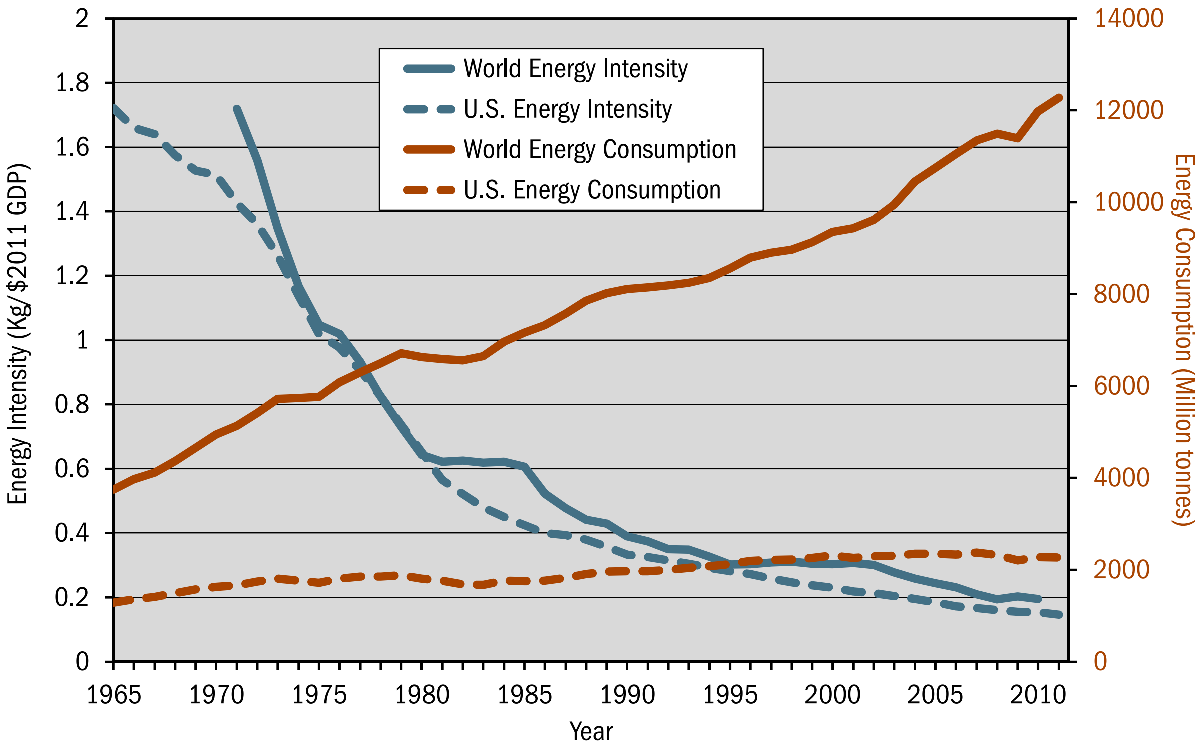

Figure 111. World and U.S. energy intensity versus energy consumption, 1965-2011.[278]

Energy intensity is expressed in kilograms of oil equivalent per dollar of GDP; energy consumption is expressed in million metric tons of oil equivalent. World energy consumption has increased by 227 percent over the period and U.S. consumption has increased 76 percent.

GDP growth is tightly linked to the consumption of energy and the production of carbon dioxide. In 2010, the creation of a dollar of GDP required the consumption of 153 grams (5.3 ounces) of oil equivalent hydrocarbon energy and resulted in the emission of 380 grams (13.4 ounces) of CO_2 equivalent greenhouse gases.

There are no unconventional fuel "panaceas" lying in wait to solve the problem of future higher-cost supplies of oil and gas. Notwithstanding the fact that in theory some of these resources have very large in situ volumes, the likely rate at which they can be converted to supply and their cost of acquisition will

277 EIA, 2012, "Annual Energy Outlook 2013 early release", Table 20.

278 GDP and energy production for energy intensity from World Bank, 2012, http://data.worldbank.org/indicator?display=default ; 1965-2011 energy production from BP, *Statistical Review of World Energy* 2012.

not allow them to quell higher energy costs and potential supply shortfalls. Shale gas and tight oil, the latest "panaceas" heralded by various pundits and vested interests, are expensive, require high levels of capital input to maintain production levels, and are unlikely to be able to maintain production over the long haul. Furthermore, increasing amounts of unconventional fuels, with their inherently lower net energy returns, mean increasing amounts of collateral environmental impacts, whether through fracking for gas and tight oil or producing tar sands, biofuels, oil shales and other unconventional sources.

A *de facto* energy strategy which assumes the availability of escalating quantities of reasonably priced hydrocarbons along with ever-increasing GDP and low unemployment without examining the supply fundamentals is a dangerous one in terms of mitigating supply shocks and other future impacts to society. The impact of high and volatile energy prices on economic growth has been made abundantly clear over the past five years, as well as during previous recessions (see Figure 10, Figure 11, and Figure 12), and there is little reason to believe that it will not continue in the future despite the rosy forecasts.

McKinsey Global Insight suggests that a "productivity response" directed at reducing consumption and more efficient use of resources could reduce demand for energy, land, water and steel (as a proxy for other commodities), compared to a business-as-usual projection, by up to 30 percent by 2030, with corresponding reductions in emissions.[279] Although such a response would not necessarily reduce capital input requirements over attempting to grow supply, it would go a long way towards mitigating the impacts of resource shortfalls on society. The opportunities for a "productivity response" McKinsey provides could be modified and expanded upon; however, maximizing conservation and efficiency is clearly a crucial first step in managing the impacts of resource scarcity in the future.

GEOPOLITICS

Geopolitical risks concerning energy supply arise from both the inequitable consumption rates of developed versus developing countries and the concentration of supply, particularly of oil, in politically unstable regions. In terms of consumption we have seen that developed countries such as the U.S. consume many times more energy per capita than developing counties: four times more than China and 17 times more than India (Figure 3). Given the correlation between GDP growth and energy consumption, rapidly growing economies will require (and demand) increasing amounts of energy. Moreover, the developing world as a whole aspires to developed world levels of energy consumption. In terms of energy supply, oil remains the most vulnerable to geopolitical risks; natural gas is an issue in Europe and Asia, however, due to both pipeline supplies out of Russia and LNG imports.

Oil is a globally priced commodity and as such the U.S. will not be exempt from price increases associated with disruptions in global supply, regardless of how much oil is produced domestically.[280] Projections from the EIA show that the U.S. will still be dependent on imports for 36% of supply (6.9 mbd) by 2040, even with optimistic assumptions on the growth of domestic production (Figure 28). It is highly unlikely that these imports could be met by North American sources from Canada and Mexico.

[279] Richard Dobbs, et al., "Resource Revolution: Meeting the world's energy, materials, food and water needs", McKinsey Global Institute, 2011, http://www.mckinsey.com/features/resource_revolution.

[280] Michael Levi, "The False Promise of Energy Independence", *New York Times*, December 21, 2012, http://www.nytimes.com/2012/12/21/opinion/the-false-promise-of-energy-independence.html.

The vulnerability of oil supplies to geopolitical disruptions is illustrated in Figure 112 by the disparate concentration of export capacity and import requirements. Fully half of the 38.3 mbd of global net exports in 2011(total oil movements are larger than this as several regions both import and export oil) were provided by the Middle East, with 12 percent of the balance provided by West Africa. These regions are political hotspots, particularly Iran, Iraq, and Nigeria, and to a lesser extent other Middle East and North African countries affected by the "Arab Spring". The former Soviet Union controlled an additional 22 percent of net exports in 2011.

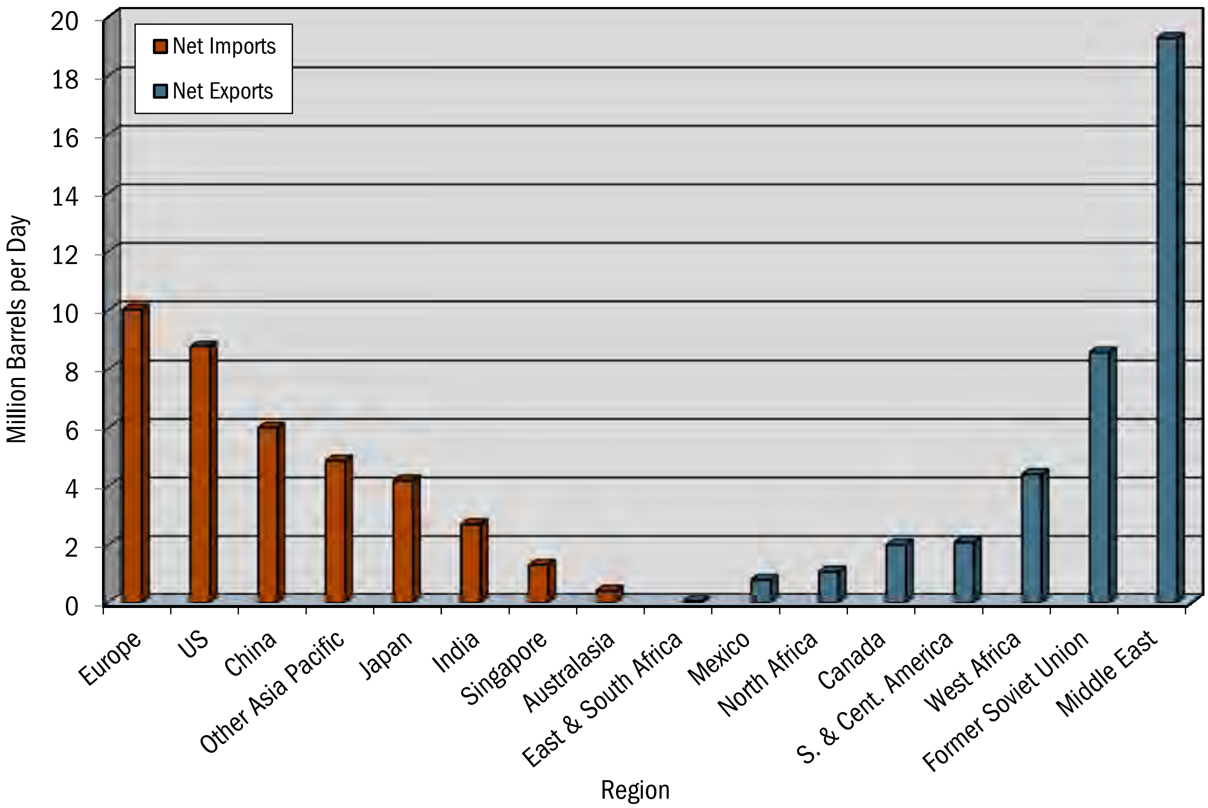

Figure 112. Global net imports and net exports of oil by region, 2011.[281]

The Middle East and West Africa, both regions prone to political instability, are responsible for 62 percent of global net exports.

Europe and the U.S. consume 49 percent of net imports, and hence are highly vulnerable to disruptions in oil supply and price shocks. Together with Japan and Singapore, the developed world consumes 63 percent of global net imports. The developing world consumes just 37 percent, but this share has been growing rapidly (China was a net exporter of oil as recently as 1993—see Figure 6—and now accounts for 16 percent of global net imports). Growing oil consumption in both China and India is rapidly putting pressure on availability and price for other major oil importers. China, in particular, has been taking an aggressive role in securing oil supplies through investments in Angola, Venezuela, Canada and elsewhere.

Global crude oil surplus production capacity in late 2012 was about 2 mbd (expected to rise to 3.3 mbd in 2013).[282] This is a very narrow margin of surplus capacity—about 2.5 percent of current world oil

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[281] Data from BP, *Statistical Review of World Energy* 2012.

consumption. Disruption of production in a major oil producer such as Iran through war or sanctions could easily remove all surplus capacity from the system. Disruption of shipping channels such as the Strait of Hormuz or the Straits of Malacca, through which 19 and 17 percent (respectively) of world oil consumption transits daily,[283] would precipitate a crisis of supply if it lasted long enough to consume global stocks of crude oil storage.

Petroleum geologist and analyst Jeffrey Brown points out an even more daunting geopolitical risk factor with respect to the availability of oil for importing nations. As consumption rises within oil-exporting nations, the available quantity of oil for export shrinks without corresponding increases in production capacity. Indonesia, for example, which was once a net exporter of oil, is now a net importer as a result of both rising domestic consumption and falling production. China and India are rapidly increasing their need for imported oil—they now consume 23 percent of available imports—which reduces the oil available for other importing nations.

Brown has developed what he terms the “Export Land Model”[284] and estimates that available oil for export from Saudi Arabia has declined by 38 percent since 2005.[285] He further suggests that total oil available for export, once the needs of China and India are met, has declined by 48 percent since 2005. Carrying this analysis forward he estimates that, if China and India’s growing import requirements are met, available net exports for the rest of the world’s importing nations could disappear by 2030.[286] This implies, to put it mildly, the possibility for geopolitical tensions and aggression as oil-importing economies compete for dwindling exports and face not only much higher prices but physical shortages.

There are many other risks to geopolitical stability emerging besides energy. Access to water, food, minerals and a host of other resources as well as the impacts of climate change will provide immense challenges. The scenario of ever-increasing energy consumption in a rate-constrained world is not only likely to be very difficult or impossible to achieve over the long term, it exacerbates many other geopolitical risk factors. A scenario of applying resources to the task of reducing energy throughput and impact on ecosystems while maintaining access to essential inputs will serve us much better in reducing overall risk and promoting longer-term sustainability.

ENVIRONMENTAL PROTECTION

The saying “there’s no such thing as a free lunch” certainly applies to the environmental costs of procuring energy, whether it comes from fossil fuels, nuclear, or renewables. There is always a cost—what varies is how high that cost is (and who pays it). The leverage of the energy humanity has harvested in the last two centuries has allowed massive alteration of ecosystems worldwide for agriculture, urbanization, resource extraction, and other human pursuits. It has also allowed lifestyles for billions of people based on energy throughputs that are tens of times larger than existed previously.

There is no thinking person who upon reflection would not admit that fossil fuels are non-renewable (despite the protests of fringe “abiotic oil” theorists). Yet we have seen that fossil fuels currently comprise over 80 percent of our consumption and are projected to continue to do so for the

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282 EIA Short Term Energy Outlook, 2012, Table 3c, http://www.eia.gov/forecasts/steo/xls/STEO_m.xls.

283 EIA, “World Oil Transit Chokepoints”, 2012, http://www.eia.gov/countries/regions-topics.cfm?fips=WOTC&trk=p3.

284 See http://en.wikipedia.org/wiki/Export_Land_Model.

285 Jeffrey J. Brown, personal communication, 2012, http://i1095.photobucket.com/albums/i475/westexas/Slide2-6_zps3f248dc1.jpg.

286 Jeffrey J. Brown, “An Update On Global Net Oil Exports: Is It Midnight On The Titanic?”, Energy Bulletin, April 24, 2012, http://www.resilience.org/stories/2012-04-24/update-global-net-oil-exports-it-midnight-titanic.

foreseeable future. We have legions of scientists telling us that continuing to rely on fossil fuels is suicidal for the climate, and yet greater legions of stockbrokers, politicians, and corporate leaders continue to herald a new bonanza of fossil fuels, based on unconventional resources. This bonanza is projected by government officials to propel us to a blissful future of a continuously growing economy with low unemployment *ad infinitum* (or at least until the charts end in 2040).

On examination, the facts of the matter are quite different:

- Conventional crude oil production is on a plateau, and maintaining production will require a herculean effort in terms of investment, new discoveries and drilling (four new Saudi Arabias would be needed by 2035).
- Shale gas and tight oil require very large amounts of capital input for drilling to offset steep production declines. Hydraulic fracturing required to produce shale gas and tight oil have environmental impacts that have been widely opposed in several countries. Production is unlikely to be sustainable in the longer term.
- Tar sands require very large amounts of capital input to scale production modestly. They have a large environmental impact and their greenhouse gas emissions are significantly higher than conventional oil.
- Biofuels are displacing other food crops and ecosystems for transportation fuels and have a very low net energy content.
- Other non-renewable unconventional sources discussed in this report are characterized by high capital inputs, high collateral environmental damage, low net energy yield, and a low ability to scale rate-of-supply.

Pursuit of unconventional fuels in an attempt to grow petroleum liquids supply to meet business-as-usual requirements is unlikely to be successful over the long haul owing to their physical properties and rate-of-supply limitations. Although unconventional fuels will be important in mitigating declines in conventional oil and gas to some extent, they are simply not scalable to the levels required in business-as-usual forecasts. Furthermore, the low net energy yields and increasingly invasive extraction methods of unconventional fuels necessarily mean increasingly larger impact on ecosystems and the climate. These include:

- *Water:* Contamination of groundwater by shale gas extraction (faulty well engineering, frack-water disposal), tar sands, and in situ coal gasification. Excessive overall water consumption required by shale gas and tight oil extraction, tar sands, oil shale and biofuels.
- *Land:* Physical footprint of drill pads, roads, mining pits, pipelines and, in the case of biofuels, ecosystems destroyed and food crops displaced to grow corn, palm oil, sugar cane, and other biomass inputs. The industrial footprint of truck traffic, compressors and rigs in built-up areas with shale gas extraction is also significant.
- *Air:* Emissions from the extraction, refining, and distribution of unconventional fuel sources. These include the emissions from drilling rigs, trucks, compressors, mining, and refining operations in populated areas and similar, although largely unnoticed, emissions in unpopulated areas.

- *Climate:* The disproportionate emissions of CO_2, methane, and other greenhouse gases from the extraction process compared to conventional hydrocarbons, owing to low net energy and invasive extraction techniques. Tar sands, for example, have well-to-wheels emissions about 23 percent higher than conventional oil.[287] A recent study in Nature suggests that methane emissions could be as high as 9 percent from some gas fields,[288] which is more than three times the average EPA estimates, and significantly higher than earlier studies showing that shale gas has a greater greenhouse gas impact over the short term (40-50 years) than coal in the production of electricity.[289]

So yes, there is no such thing as a free lunch. Even wind turbines and photovoltaic cells require the expenditure of hydrocarbon energy in the extraction of the raw materials used in their manufacture, as well as their manufacture itself, and the imposition of wind turbines on the landscape has increasingly been the subject of organized opposition.

All this points to the need to rethink our approach to energy. The rates of energy throughput enjoyed for the past century are not sustainable. By rethinking the way we organize ourselves and expend energy to reduce requirements as much as possible we will ensure a much less disruptive transition to a world with less energy. This will not be a world without hydrocarbons, at least not for the foreseeable future, but it will be a world where energy is more sustainable, environmental impacts are minimized, and climate change can be mitigated.

287 Natural Resources Defense Council, "Report: Fuel from Canadian Tar Sands Significantly Dirtier Than Average", February 9, 2011, http://switchboard.nrdc.org/blogs/smui/european_commission_report_fin.html.
288 Jeff Tollefson, "Methane leaks erode green credentials of natural gas", *Nature* 493, 12 (January 3, 2013), http://www.nature.com/news/methane-leaks-erode-green-credentials-of-natural-gas-1.12123.
289 J.D. Hughes, "Life Cycle Greenhouse Gas Emissions from Shale Gas Compared to Coal: An Analysis of Two Conflicting Studies", Post Carbon Institute, 2011, http://www.postcarbon.org/reports/PCI-Hughes-NETL-Cornell-Comparison.pdf.

Conclusion

Fossil fuels have propelled an immense growth in population, per capita energy consumption and total energy consumption in a mere 160 years (Figure 1). Growth in GDP and the health of the economy has been tightly linked with growth in consumption of energy, yet more than 80 percent of that energy is currently provided by finite, non-renewable fossil fuels. Rhetoric based on estimates of the in situ resources of unconventional fossil fuels suggests that hydrocarbons will be abundant and can provide a major part of the growth in energy consumption required to sustain the economy over the next 25 years.

Projections from the latest EIA International Energy Outlook reference case suggest that world energy consumption will grow by 44 percent from 2011 through 2035, by which time population will have grown 23 percent and per capita energy consumption will have grown 14 percent (Figure 113). The cumulative amount of energy consumption required to sustain such an increase amounts to 71 percent of all the hydrocarbons consumed between 1850 and 2011—in just 24 years. This would get us to 10 times the average per capita energy consumption of 1850 and 70 times the total energy throughput.

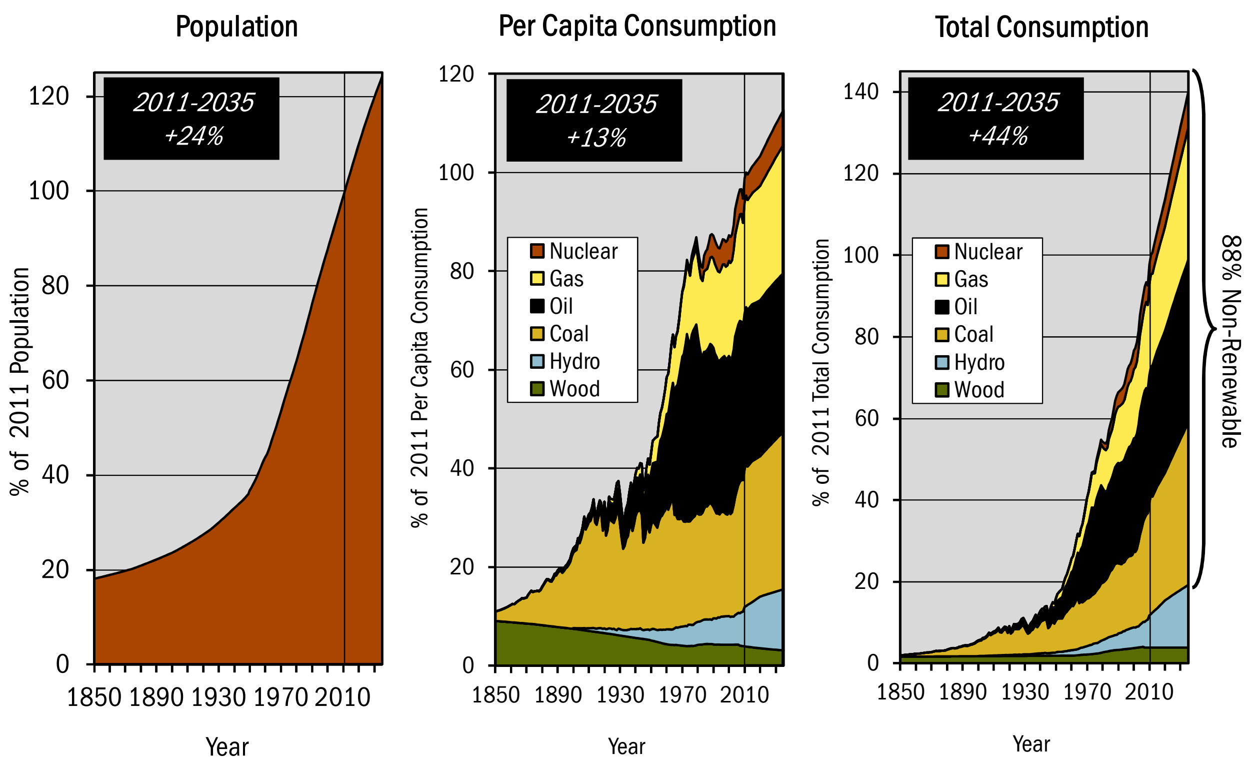

Figure 113. World population, per capita-, and total-energy consumption by fuel as a percentage of 2011 consumption, 1850-2035,.[290]

This is what the world's energy consumption profile would look like in 2035 assuming the EIA reference case projection for growth in global energy consumption and forecasts of growth in world population come to fruition.

Much of the optimism in the EIA projections is unwarranted, given an analysis of the energy supply options they are based on. Yet the EIA projections are conservative compared to some of the hype

[290] Data from Arnulf Grubler, "Technology and Global Change: Data Appendix," 1998, http://www.iiasa.ac.at/~gruebler/Data/TechnologyAndGlobalChange/; BP, *Statistical Review of World Energy*, 2012; U.S. Census Bureau, 2012, http://www.census.gov/population/international/data/idb/informationGateway.php; global projections from EIA International Energy Outlook 2011, reference case, September, 2011, http://www.eia.gov/forecasts/ieo/

propagated by various groups, often vested interests, on shale gas, tight oil, and other unconventional resources fueling a new renaissance in energy consumption and "energy independence." Although unconventional fuels are now and will continue to be important in offsetting terminal declines in the production of conventional resources, viewing them as panaceas to avoid addressing the longer-term energy sustainability dilemma facing mankind, due to its reliance on finite, non-renewable fossil fuels, is dangerous. This dilemma will eventually have to be faced whether it is ignored or not.

An objective understanding of energy realities is crucial for minimizing the societal impacts of a transition from the current paradigm requiring continuous large and unsustainable increases in energy consumption to a new paradigm with a much lower energy footprint—and which is inherently more sustainable. Although some unconventional fuels potentially have a very large in situ resource base, they suffer from low net energy yield, the need for large and continuous inputs of capital, rate-of-supply limitations, and large environmental impacts in their extraction.

Unconventional fuels are not a panacea for an endless extension of the growth paradigm. At best they are a high-cost interim source of energy that will mitigate some of the impacts of the decline in production of lower-cost conventional fuels. They can buy some time to facilitate the development of the infrastructure that will be required to reduce energy throughputs. But to view them as "game-changers" capable of indefinitely increasing the supply of low-cost energy which has underpinned the economic growth of the past century is a mistake. Hopefully the analysis of the portfolio of unconventional fuels provided in this report will provide an understanding of the realities and risks of such a course of action.

Hydrocarbons have been a tremendous onetime energy bonanza for the human race; their unique properties and versatility will be very difficult or impossible to replace. Unfortunately they are a finite, non-renewable resource, with sizeable collateral environmental impacts in their extraction and utilization. They will be needed to develop infrastructure for a more sustainable energy future. It is imperative that planning for that future be based on a foundation of objective facts, not wishful thinking.

ABBREVIATIONS

/d — per day

bbl — barrel

bbls — barrels

bcf — billion cubic feet

Btu — British thermal unit (1,055 Joules)

CAPP — Canadian Association of Petroleum Producers

EIA — Energy Information Administration of the U.S. Department of Energy

ERCB — Alberta Energy Resources Conservation Board

EUR — estimated ultimate recovery

GDP — Gross Domestic Product

IEA — International Energy Agency — the energy watchdog of the Organization for Economic Cooperation and Development (OECD)

IP — initial productivity (i.e., of a well) — typically the highest rate of production over well lifetime achieved in the first month of production

Kbbls — thousand barrels

mbd — million barrels per day

mcf — thousand cubic feet

MMcf — million cubic feet

MMbtu — million British thermal units

NEB — Canadian National Energy Board

SAGD — Steam-Assisted Gravity Drainage

tcf — trillion cubic feet

TRR — technically recoverable resources

URR — ultimate recoverable resources

USGS — United States Geological Survey

Crude oil — As used herein, conventional crude oil not including natural gas liquids, biofuels or refinery gains.

Horizontal well — A well typically started vertically which is curved to horizontal at depth to follow a particular rock stratum or reservoir.

Hydraulic fracturing ("fracking") — The process of inducing fractures in reservoir rocks through the injection of water and other fluids, chemicals and solids under very high pressure.

Multi-stage hydraulic-fracturing — Each individual hydraulic fracturing treatment is a "stage" localized to a portion of the well. There may be as many as 30 individual hydraulic fracturing stages in some wells.

Oil shale — Organic-rich rock that contains kerogen, a precursor of oil. Depending on organic content it can sometimes be burned directly with a calorific value equivalent to a very low grade coal. Can be "cooked" in situ at high temperatures for several years to produce oil or can be retorted in surface operations to produce petroleum liquids.

Petroleum liquids (also, "liquids") — All petroleum-like liquids used as liquid fuels including crude oil, lease condensates, natural gas liquids, refinery gains and biofuels.

Play — A prospective area for the production of oil, gas or both. Usually a relatively small contiguous geographic area focused on an individual reservoir.

Reserve — A deposit of oil, gas or coal that can be recovered profitably within existing economic conditions using existing technologies. Has legal implications in terms of company valuations for the Securities and Exchange Commission.

Shale gas — Gas contained in shale with very low permeabilities in the micro- to nano-darcy range. Typically produced using horizontal wells with multi-stage hydraulic fracture treatments.

Shale oil — See "tight oil."

Stripper well — An oil or gas well that is nearing the end of its economically useful life. In the U.S., a "stripper" gas well is defined by the Interstate Oil and Gas Compact Commission as one that produces 60,000 cubic feet (1,700 m^3) or less of gas per day at its maximum flow rate. Oil wells are generally classified as stripper wells when they produce ten barrels per day or less for any 12-month period.

Tank-to-wheels emissions — Emissions generated from burning gasoline or diesel fuel not considering the emissions in the extraction and refining process.

Tight oil — Also referred to as shale oil. Oil contained in shale and associated clastic and carbonate rocks with very low permeabilities in the micro- to nano-darcy range. Typically produced using horizontal wells with multi-stage hydraulic fracture treatments.

Type decline curve — The average production declines for all wells in a given area or play from the first month on production. For shale plays in this study the type decline curves considered the average of the first four to five years of production.

Undiscovered technically recoverable resource — Resources inferred to exist using probabilistic methods extrapolated from available exploration data and discovery histories. Usually designated with confidence levels. For example, P90 indicates a 90 percent chance of having a least the stated resource volume whereas a P10 estimate has only a 10 percent chance.

Well-to-wheels emissions — Full cycle emissions including those associated with extraction, refining and burning at point of use.

Zimmerman & Associates

Environmental Litigation, Mediation, Enforcement & Compliance, Counseling

February 27, 2013

U.S. Department of Energy (FE–34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
P.O. Box 44375
Washington, DC 20026-4375

LNGStudy@hq.doe.gov.

Re: 2012 LNG Export Study – Oversized Document in Support Of Rebuttal Comments

Dear Sirs:

On behalf of Damascus Citizens for Sustainability, Inc. and NYH20, Inc., we submitted rebuttal comments on the 2012 LNG Export Study by NERA Consulting by letter dated February 25, 2013. These rebuttal comments were submitted by email prior to the 4:30 p.m. EST comment deadline. Attached to this comment letter were two documents. A third document could not be submitted by email because it was too large a file to be transmitted by our internet service provider. We only learned this when we received an email from the service provider informing us that the file could not be sent to you due to its size. One of the two documents that were attached to our comments was an executive summary of this third document and we incorporated a quotation from this executive summary in our comment letter. In order to assure that you have the full report, we contacted Mr. John Anderson, the individual listed as the point of contact in the Federal Register notice, and after checking with his legal counsel, he requested that we deliver the document on a compact disk and include this letter to explain why this document is being submitted after the comment deadline.

If you have any questions about this matter, please contact me at your convenience.

Sincerely,

/s/ J.J. Zimmerman

Jeff Zimmerman
counsel for Damascus Citizens for
Sustainability and NYH2O

Attachment on disk

13508 Maidstone Lane, Potomac, MD 20854 (240) 912- 6685 (office); (301) 963-9664 (fax)

From:	Jeff Zimmerman
To:	LNGStudy
Cc:	"B. Arrindell"; "Joe Levine"
Subject:	Rebuttal Comments re DOE NERA LNG Study
Date:	Monday, February 25, 2013 4:30:03 PM
Attachments:	Rebuttal Comments for DCS and NYH2O.doc Deborah Rogers SWS-report-FINAL.pdf Post Carbon Institute DBD-Exec-Summary.pdf

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Dear Sirs;

Attached are rebuttal comments for Damascus Citizens for Sustainability and NYH2O, including two reports as attachments.

Sincerely, Jeff Zimmerman

Jeff Zimmerman
Zimmerman & Associates
13508 Maidstone Lane
Potomac, MD 20854
(240) 912-6685 (office)
(202) 262-9664 (cell)
jjzimmerman@comcast.net

Zimmerman & Associates

Environmental Litigation, Mediation, Enforcement & Compliance, Counseling

February 25, 2013

U.S. Department of Energy (FE–34)
Office of Natural Gas Regulatory Activities
Office of Fossil Energy
P.O. Box 44375
Washington, DC 20026-4375

LNGStudy@hq.doe.gov.

Re: 2012 LNG Export Study – Rebuttal Comments

Dear Sirs:

On behalf of Damascus Citizens for Sustainability, Inc. and NYH20, Inc., we hereby submit for your consideration the attached additional information as comments on the 2012 LNG Export Study by NERA Consulting. However, as an initial matter, it is the responsibility of the Department of Energy under the National Environmental Policy Act to prepare and consider an environmental impact statement on the agency's program to dramatically increase the number of LNG export facilities that are anticipated to be built and operated in the coastal areas of the United States. As reported on the Federal Energy Regulatory Commission's LNG website (http://www.ferc.gov/industries/gas/indus-act/lng.asp, last visited at 3:45 p.m. EST today), as of February 21, 2013, there are 11 existing LNG export terminals, 6 more approved but not yet completed, 8 more proposed, and 9 more identified by project sponsors as potential projects. This is a total of 34 LNG export terminals.

If ever there were a program for which a programmatic environmental impact statement ought to be prepared, this is such a program. Both the Council on Environmental Quality regulations (40 CFR Part 1500-1508) and the Department of Energy's NEPA Procedures (10 CFR Part 1021) require preparation and consideration of a programmatic EIS in this case. The DOE NEPA procedures define a "program" requiring a programmatic EIS as, "a sequence of connected or related DOE actions or projects as discussed at 40 CFR 1508.18(b)(3) and 1508.25(a)."

This brings us to our other rebuttal comments. Attached to this letter are two substantial and important reports that demonstrate that the economics of shale gas production will not sustain the level of production necessary to support anywhere near the number of LNG export terminals already existing or anticipated at the present time based on the data from FERC noted above. The first of these reports is "*Shale and Wall Street: Was the Decline in Natural Gas Prices Orchestrated?*" by noted energy economist Deborah Rogers of the Energy Policy Forum. The second report is "*Drill, Baby, Drill: Can Unconventional Fuels Usher In a New Era of Energy Abundance?*" by J. David Hughes of the Post Carbon Institute. As Ms. Rogers concludes in the executive summary of her report, "It is imperative that shale [gas] be examined thoroughly and independently to assess the true value of shale [gas] assets, particularly since policy on both the state and national level is being implemented based on production projections that are overtly optimistic (and thereby unrealistic) and wells that are significantly underperforming original projections." Mr. Hughes reaches essentially the same conclusion, stating, "the projections by pundits and some government agencies that these technologies [shale gas from fracking and other technologies] can provide endless growth heralding a new era of "energy independence," in which the U.S. will become a substantial net exporter of energy, are entirely unwarranted based on the fundamentals. At the end of the day, fossil fuels are finite and these exuberant forecasts will prove to be extremely difficult or impossible to achieve." Both of these reports were published after the original comment deadline in this matter. Both should be carefully and fully considered by the Department as part of its evaluation.

We appreciate the opportunity to submit these comments. Please contact me at your convenience if you have any questions.

Sincerely,

/s/ J.J. Zimmerman

Jeff Zimmerman
counsel for Damascus Citizens for
Sustainability and NYH2O

Attachments
(sent by separate email)

EXECUTIVE SUMMARY

DRILL, BABY, DRILL

CAN UNCONVENTIONAL FUELS USHER IN A NEW ERA OF ENERGY ABUNDANCE?

BY J. DAVID HUGHES

FEB 2013

POST CARBON INSTITUTE

Executive Summary

World energy consumption has more than doubled since the energy crises of the 1970s, and more than 80 percent of this is provided by fossil fuels. In the next 24 years world consumption is forecast to grow by a further 44 percent—and U.S. consumption a further seven percent—with fossil fuels continuing to provide around 80 percent of total demand.

Where will these fossil fuels come from? There has been great enthusiasm recently for a renaissance in the production of oil and natural gas, particularly for the United States. Starting with calls in the 2008 presidential election to “drill, baby, drill!,” politicians and industry leaders alike now hail “one hundred years of gas” and anticipate the U.S. regaining its crown as the world's foremost oil producer. Much of this optimism is based on the application of technologies like hydraulic fracturing (“fracking”) and horizontal drilling to previously inaccessible shale reservoirs, and the development of unconventional sources such as tar sands and oil shale. Globally there is great hope for vast increases in oil production from underdeveloped regions such as Iraq.

However, the real challenges—and costs—of 21st century fossil fuel production suggest that such vastly increased supplies will not be easily achieved or even possible. The geological and environmental realities of trying to fulfill these exuberant proclamations deserve a closer look.

Context: History and forecasts

Despite the rhetoric, the United States is highly unlikely to become energy independent unless rates of energy consumption are radically reduced. The much-heralded reduction of oil imports in the past few years has in fact been just as much a story of reduced consumption, primarily related to the Great Recession, as it has been a story of increased production. Crude oil production in the U.S. provides only 34 percent of current liquids supply, with imports providing 42 percent (the balance is provided by natural gas liquids, refinery gains, and biofuels). In fact, the Energy Information Administration (EIA) sees U.S. domestic crude oil production—even including tight oil (shale oil)—peaking at 7.5 million barrels per day (mbd) in 2019 (well below the all-time U.S. peak of 9.6 mbd in 1970), and by 2040 the share of domestically produced crude oil is projected to be lower than it is today, at 32 percent. And yet, the media onslaught of a forthcoming energy bonanza persists.

Metrics: Size, Rate of Supply, and Net Energy

The metric most commonly cited to suggest a new age of fossil fuels is the estimate of *in situ* unconventional resources and the purported fraction that can be recovered. These estimates are then divided by current consumption rates to produce many decades or centuries of future consumption. In fact, two other metrics are critically important in determining the viability of an energy resource:

- ***The rate of energy supply***—that is, the rate at which the resource can be produced. A large in situ resource does society little good if it cannot be produced consistently and in large enough quantities, characteristics that are constrained by geological, geochemical and geographical factors (and subsequently manifested in economic costs). For example, although resources such as oil shale, gas hydrates, and in situ coal gasification have a very large in situ potential, they have been produced at only miniscule rates if at all, despite major expenditures over many years on pilot projects. Tar sands similarly have immense in situ resources, but more than four decades of very large capital inputs and collateral environmental impacts have yielded production of less than two percent of world oil requirements.

- *The net energy yield* of the resource, which is the difference between the energy input required to produce the resource and the energy contained in the final product. The net energy, or "energy returned on energy invested" (EROEI), of unconventional resources is generally much lower than for conventional resources. Lower EROEI translates to higher production costs, lower production rates and usually more collateral environmental damage in extraction.

Thus the world faces not so much a *resource* problem as a *rate of supply* problem, along with the problem of the collateral environmental impacts of maintaining sufficient rates of supply.

DATA: PRODUCTION, TRENDS, AND CONSTRAINTS

This report provides an in-depth evaluation of the various unconventional energy resources behind the recent "energy independence" rhetoric, particularly shale gas, tight oil ("shale oil"), and tar sands. In particular, the shale portions of this report are based on the analysis of production data for 65,000 wells from 31 shale plays using the DI Desktop/HPDI database, which is widely used in industry and government.

Shale gas

Shale gas production has grown explosively to account for nearly 40 percent of U.S. natural gas production; nevertheless production has been on a plateau since December 2011 —80 percent of shale gas production comes from five plays, several of which are in decline. The very high decline rates of shale gas wells require continuous inputs of capital—estimated at $42 billion per year to drill more than 7,000 wells—in order to maintain production. In comparison, the value of shale gas produced in 2012 was just $32.5 billion.

The best shale plays, like the Haynesville (which is already in decline) are relatively rare, and the number of wells and capital input required to maintain production will increase going forward as the best areas within these plays are depleted. High collateral environmental impacts have been followed by pushback from citizens, resulting in moratoriums in New York State and Maryland and protests in other states. Shale gas production growth has been offset by declines in conventional gas production, resulting in only modest gas production growth overall. Moreover, the basic economic viability of many shale gas plays is questionable in the current gas price environment.

Tight oil (shale oil)

Tight oil production has grown impressively and now makes up about 20 percent of U.S. oil production. This has helped U.S. crude oil production reverse years of decline and grow 16 percent above its all-time post-1970 low in 2008. More than 80 percent of tight oil production is from two unique plays: the Bakken in North Dakota and Montana and the Eagle Ford in southern Texas. The remaining nineteen tight oil plays amount to less than 20 percent of total production, illustrating the fact that high-productivity tight oil plays are in fact quite rare.

Tight oil plays are characterized by high decline rates, and it is estimated that more than 6,000 wells (at a cost of $35 billion annually) are required to maintain production, of which 1,542 wells annually (at a cost of $14 billion) are needed in the Eagle Ford and Bakken plays alone to offset declines. As some shale wells produce substantial amounts of both gas and liquids, taken together shale gas and tight oil require about 8,600 wells per year at a cost of over $48 billion to offset declines. Tight oil production is projected to grow substantially from current levels to a peak in 2017 at 2.3 million barrels per day. At that point, all drilling locations will have been used in the two largest plays (Bakken and Eagle Ford) and production will collapse back to 2012 levels by 2019, and to 0.7 million barrels per day by 2025. In short, tight oil production from these plays will be a bubble of about ten years' duration.

Tar sands

Tar sands oil is primarily imported to the U.S. from Canada (the number one supplier of U.S. oil imports), although it has recently been approved for development in Utah. It is low-net-energy oil, requiring very high levels of capital inputs (with some estimates of over $100 per barrel required for mining with upgrading in Canada) and creating significant collateral environmental impacts. Additionally it is very time- and capital-intensive to grow tar sands oil production, which limits the potential for increasing production rates.

Production growth forecasts have tended to be very aggressive, but they are unlikely to be met owing to logistical constraints on infrastructure development and the fact that the highest quality, most economically viable portions of the resource are being extracted first. The economics of much of the vast purported remaining extractable resources are increasingly questionable, and the net energy available from them will diminish toward the breakeven point long before they are completely extracted.

Other resources

Other unconventional fossil fuel resources, such as oil shale, coalbed methane, gas hydrates, and Arctic oil and gas—as well as technologies like coal- and gas-to-liquids, and in situ coal gasification—are also sometimes proclaimed to be the next great energy hope. But each of these is likely to be a small player in terms of rate of supply for the foreseeable future even though they have large *in situ* resources.

Deepwater oil and gas production make up a notable (yet still small) share of U.S. energy consumption, but growth prospects for these resources are minimal, and opening up coastal areas currently under moratoriums would expand access to only relatively minor additional resources. Production of biofuels, although not fossil fuels, is projected to be essentially flat for at least the next two decades (while requiring significant fossil fuel inputs) and will remain a minor player in terms of liquid fuel consumption.

CONCLUSION

The U.S. is a mature exploration and development province for oil and gas. New technologies of large scale, multistage, hydraulic fracturing of horizontal wells have allowed previously inaccessible shale gas and tight oil to reverse the long-standing decline of U.S. oil and gas production. This production growth is important and has provided some breathing room. Nevertheless, the projections by pundits and some government agencies that these technologies can provide endless growth heralding a new era of "energy independence," in which the U.S. will become a substantial net exporter of energy, are entirely unwarranted based on the fundamentals. At the end of the day fossil fuels are finite and these exuberant forecasts will prove to be extremely difficult or impossible to achieve.

A new energy dialogue is needed in the U.S. with an understanding of the true potential, limitations, and costs—both financial and environmental—of the various fossil fuel energy panaceas being touted by industry and government proponents. The U.S. cannot drill and frack its way to “energy independence.” At best, shale gas, tight oil, tar sands, and other unconventional resources provide a temporary reprieve from having to deal with the real problems: fossil fuels are finite, and production of new fossil fuel resources tends to be increasingly expensive and environmentally damaging. Fossil fuels are the foundation of our modern global economy, but continued reliance on them creates increasing risks for society that transcend our economic, environmental, and geopolitical challenges. The best responses to this conundrum will entail a rethink of our current energy trajectory.

Unfortunately, the “drill, baby, drill” rhetoric in recent U.S. elections belie any understanding of the real energy problems facing society. The risks of ignoring these energy challenges are immense. Developed nations like the United States consume (on a per capita basis) four times as much energy as China and seventeen times as much as India. Most of the future growth in energy consumption is projected to occur in the developing world. Constraints in energy supply are certain to strain future international relations in unpredictable ways and threaten U.S. and global economic and political stability. The sooner the real problems are recognized by political leaders, the sooner real solutions to our long term energy problem can be implemented.

FEBRUARY 2013

SHALE AND WALL STREET:

WAS THE DECLINE IN NATURAL GAS PRICES ORCHESTRATED?

Deborah Rogers

ENERGY POLICY FORUM

Contents

Executive summary

In 2011, shale mergers and acquisitions (M&A) accounted for $46.5B in deals and became one of the largest profit centers for some Wall Street investment banks. This anomaly bears scrutiny since shale wells were considerably underperforming in dollar terms during this time. Analysts and investment bankers, nevertheless, emerged as some of the most vocal proponents of shale exploitation. By ensuring that production continued at a frenzied pace, in spite of poor well performance (in dollar terms), a glut in the market for natural gas resulted and prices were driven to new lows. In 2011, U.S. demand for natural gas was exceeded by supply by a factor of four.

It is highly unlikely that market-savvy bankers did not recognize that by overproducing natural gas a glut would occur with a concomitant severe price decline. This price decline, however, opened the door for significant transactional deals worth billions of dollars and thereby secured further large fees for the investment banks involved. In fact, shales became one of the largest profit centers within these banks in their energy M&A portfolios since 2010. **The recent natural gas market glut was largely effected through overproduction of natural gas in order to meet financial analyst's production targets and to provide cash flow to support operators' imprudent leverage positions**.

As prices plunged, Wall Street began executing deals to spin assets of troubled shale companies off to larger players in the industry. Such deals deteriorated only months later, resulting in massive write-downs in shale assets. In addition, the banks were instrumental in crafting convoluted financial products such as VPP's (volumetric production payments); and despite of the obvious lack of sophisticated knowledge by many of these investors about the intricacies and risks of shale production, these products were subsequently sold to investors such as pension funds. Further, leases were bundled and flipped on unproved shale fields in much the same way as mortgage-backed securities had been bundled and sold on questionable underlying mortgage assets prior to the economic downturn of 2007.

As documented in this report, emerging independent information on shale plays in the U.S. confirms the following:

- Wall Street promoted the shale gas drilling frenzy, which resulted in prices lower than the cost of production and thereby profited [enormously] from mergers & acquisitions and other transactional fees.

- U.S. shale gas and shale oil reserves have been overestimated by a minimum of 100% and by as much as 400-500% by operators according to actual well production data filed in various states.

- Shale oil wells are following the same steep decline rates and poor recovery efficiency observed in shale gas wells.

- The price of natural gas has been driven down largely due to severe overproduction in meeting financial analysts' targets of production growth for share appreciation coupled and exacerbated by imprudent leverage and thus a concomitant need to produce to meet debt service.

- Due to extreme levels of debt, stated proved undeveloped reserves (PUDs) may not have been in compliance with SEC rules at some shale companies because of the threat of collateral default for those operators.

- Industry is demonstrating reticence to engage in further shale investment, abandoning pipeline projects, IPOs and joint venture projects in spite of public rhetoric proclaiming shales to be a panacea for U.S. energy policy.

- Exportation is being pursued for the differential between the domestic and international prices in an effort to shore up ailing balance sheets invested in shale assets

It is imperative that shale be examined thoroughly and independently to assess the true value of shale assets, particularly since policy on both the state and national level is being implemented based on production projections that are overtly optimistic (and thereby unrealistic) and wells that are significantly underperforming original projections.

Introduction

Unconventional oil and gas from shales has been claimed to be a game changer, revolutionary, “a gift and national treasure”. Resource estimates for the U.S. have been giddily referred to as larger than “two Saudi Arabias” by Chesapeake Energy CEO Aubrey McClendon. It has even been said that shale oil and gas will provide energy independence for the U.S.

While such statements are expected from an industry which stands to gain monetarily, a careful, thorough and independent examination of shale production data and company filings demonstrate that shale promises have been vastly overstated, leading to troubling prognostications for the shale industry as a whole and for those regions exploited or planning to be exploited for this resource.

Shale development is not about long-term economic promise for a region. Such economic promise has failed to materialize beyond the first few years of a shale play's life in any region of the U.S. today that has relative shale maturity. Retail sales per capita and median household income in the core counties of the major plays are underperforming their respective state averages in direct opposition to spurious economic models commissioned by industry (see charts in Appendix).

Shale development is not about job creation. Optimistic job estimates by industry have relied heavily on unrealistic multipliers to claim vast numbers of indirect jobs.[1] Such job estimates in industry studies often include professions such as strippers and prostitutes in the overall job gains[2]—not the sort of jobs that most people think of when they hear optimistic numbers from the oil and gas industry. Moreover, direct industry jobs (for onshore and offshore oil and gas) have accounted for less than 1/20 of 1% of the overall U.S. labor market since 2003, according to the Bureau of Labor Statistics.[3] This cannot be construed as game changing job creation.

Shale development is not about the long-term financial viability of shale wells. The wells have not performed up to expectations. Well decline curves are precipitously steep in shale gas and even steeper in shale oil based on historical production data filed by the operators in various states. Typical shale gas wells have an average field decline of 29-52%+ per annum while shale oil fields are declining at about 40%+ per annum.[4] Industry admits that 80% of shale wells “can easily be uneconomic.”[5] Massive write-downs have recently occurred which call into question the financial viability of shale assets and possibly even shale companies. In one case, assets were written off for more than 50% of the purchase price within a matter of months.[6]

Further troubling is the realization that shale assets classified as PUDs (proved undeveloped) may not have been properly reclassified by some operators per SEC rules because such reclassification would have resulted in collateral default. The fact that other industry players have been reluctant recently to bid on assets in the Utica shale of Ohio and have abandoned plans for a pipeline for the Bakken shale in North Dakota would seem to suggest a recognition within the industry of the questionable economics and short life span of shales.[7]

Shale development is not about vast reserves or “100 years of gas.” A recently published report reviewing production data of over 60,000 shale gas and oil wells observes that

U.S. shale gas has been on a plateau since December 2011, and that 80 percent of shale gas production comes from five plays, several of which are in decline.[8] Further, according to a recent report by the Oil and Gas Journal, and industry publication, it is confirmed that the recovery efficiencies of shale plays are truly dismal. It is stated:

> "The recovery efficiency for the five major [shale gas] plays averages 6.5% and ranges from 4.7% to 10% ...this contrasts significantly with recovery efficiencies of 75-80% for conventional gas fields."[9]

Nor is shale development about technological advancements. Longer laterals have offered little in increased production, even in shale oil. Additional fracture stimulation stages also resulted in very little production gain according to studies conducted by the U.S. Geological Survey.[10]

Due to irresponsibly high debt levels, low cash, and the need to meet production targets for share appreciation, the price of both natural gas and natural gas liquids (NGLs) has been driven to new lows.[11] This complicates the shale picture enormously since margins are now non-existent. Exportation and its concomitant lucrative price spread is clearly seen by industry as offering the best hope for recovering losses.

The new business model of shales

Shale exportation provides a new frontier for shale development in the U.S. Operators are pushing lawmakers to open up vast tracts of land for exploration and development. This would clearly benefit the companies by giving them access at minimal cost and minimal future hassle.

Because of the favorable business climate, including exemption from all major federal environmental statutes and the willingness of some lawmakers to push for exportation, the U.S. has emerged as the preferred location for shale development by large multinational corporations.

It is also interesting to note that in countries such as Poland, once touted as the shale gas savior of Europe, industry has begun to abandon plans to exploit the resource due to higher costs and poor well production.[12] According to Deputy Environment Minister Piotr Wozniak, supplies have so far produced only "humble" results.

Fewer financial and environmental hurdles obviously lead to higher potential for margins and thereby profits. Given the slim margins in shale production at best, it makes good business sense to exploit the U.S. Unfortunately, adequate safeguards are not in place for those communities where such exploitation will take place.

In short, the lower the overall cost to extract shale hydrocarbons, the greater the profit spread particularly when the gas is exported. If export terminals were available today in the U.S., industry could extract, pipe, refine and ship shale gas to Asia for approximately $9/mcf. They would currently get paid as much as $18/mcf. Obviously, this is a highly lucrative spread.

In October of 2011, the Department of Energy granted the first shale gas export permit to Cheniere Energy. At that time, another 7 permits were pending which collectively committed approximately 20% of U.S. shale gas for export. One year later, in November of 2012, the number of permits had grown to 18 and the percentage of shale gas committed for export has grown significantly, accounting for approximately 60% of current U.S. consumption.[13]

It is interesting to note that while once the oil and gas industry exploited other regions of the globe to effect energy security for the U.S., it is now exploiting the U.S. to provide energy security to other regions, primarily Asia. These economies will pay the highest price and thereby offer the most profitability to the individual corporations.

It is, therefore, imperative to take a dispassionate view of this industry. Platform rhetoric about energy independence is nonsense as most within the industry realize. Further, oil and gas companies are not in business to steward the environment, save the family farm or pull depressed areas out of economic decline. If these things should by chance happen, they are merely peripheral to the primary mission of the companies and certainly were never considered in corporate exploration and production plans. Further, given shales' steep declines and thus limited lives, such benefits will be short-lived as well. It would be the height of naïveté to assume that such companies have altruistic intent towards a region or its residents. They do not. Oil and gas companies are in business to extract hydrocarbons as cheaply and efficiently as possible and get them to the customer that will pay the highest price. If they can shave dollars off already thin margins by refusing to use pollution control devices then that is precisely what they will do if it is not mandated, regardless of whether this will increase costs for a region due to pollution or negatively impact other industries. Even though pollution and degradation involve real costs, they are not borne by the industry that perpetrates them in today's economic accounting. This is especially true of the oil and gas industry as they are exempt from federal environmental protection statutes.

If shale developers can export their product to Asia where they will be paid multiples of what they can expect domestically, then that is where the gas will go. Additionally, the oil and gas industry is not in business to provide chemical, plastic and fertilizer manufacturers in the U.S. with low cost feed stock to the obvious detriment of their own bottom lines. Again, this would never be a part of their business model. Nor should it.

The energy context

For the past 100 years fossil fuels have held the primary position as the drivers of the U.S. and western economies. Nevertheless, fossil fuels are finite. New deposits of hydrocarbons have proven harder and harder to replace. Indeed, for more than a decade the largest oil and gas producers (the "Majors" as they are collectively called) have not been able to materially expand their reserve replacement ratios.[14] In fact, approximately one quarter of their reserve growth has come from acquisitions rather than the drill bit, such as ExxonMobil's acquisition of XTO Energy. This constitutes consolidation rather than organic growth.

To give another example, in 2010 Chevron replaced less than one fourth of the oil and gas it had sold the prior year.[15] This is highly problematic for the future share price of these companies and explains the exuberant share repurchase programs which they have engaged in recently, buying back shares in excess of as much $5 billion a quarter in the case of ExxonMobil.[16]

This is, of course, highly problematic for the future health of global economies. It is also problematic for the share prices of the individual fossil fuel companies.

Further, there are various grades and types of hydrocarbons, some much more efficient as fuels than others. Additionally, some hydrocarbons simply require such an expenditure of energy to extract and produce that their use becomes questionable. This measure is referred to EROI (energy returned on investment) and is often seen as a ratio. For instance, it is estimated that in the early days of the U.S. oil industry, the EROI for oil was 100:1 (that is, 100 units of energy recovered for every one unit of energy invested)[17] but this has since declined to an EROI of under 20:1.[18] Because unconventional hydrocarbons like tar sands and shales are by definition more challenging (i.e., more energy-intensive) to produce, they generally have very low EROIs: likely well under 5:1.[19]

Additionally, although industry boldly exclaims each new hydrocarbon discovery with hyperbole, there is a general consensus that we are on the downward slope of hydrocarbon abundance. In April 2011, the chief economist of the International Energy Agency (IEA) Fatih Birol stated: “We think that the crude oil production has already peaked, in 2006.”[20]

Street economics: The roots of the crisis

In an environment of declining crude reserves and a now-necessary reliance on low-EROI unconventional hydrocarbons, the oil and gas industry launched a public relations campaign with shale gas and oil of disproportionate scale to the actual performance of the wells. From a business perspective, of course, this made perfect sense.

The financial markets are intricately married to large multinational corporations. Without such markets, companies would be small and local rather than the transnational behemoths of today. Therefore, the growth of companies and the growth of economies relies heavily on the global capital markets.

In order for a publicly traded oil and gas company to grow extensively, it must manage not only its core business but also the relationship it enjoys with its investment bankers. Thus, publicly traded oil and gas companies have essentially two sets of economics. There is what may be called field economics, which addresses the basic day to day operations of the company and what is actually occurring out in the field with regard to well costs, production history, etc.; the other set is Wall Street or “Street” economics. This entails keeping a company attractive to financial analysts and investors so that the share price moves up and access to the capital markets is assured.

“Street” economics has more to do with the frenzy we have seen in shales than does actual well performance in the field.

With the help of Wall Street analysts acting as primary proponents for shale gas and oil, the markets were frothed into a frenzy. Boom cycles have the inherent characteristic of optimism. If left unchecked, such optimism can metamorphose into a mania such as we saw several years ago in the lead up to the mortgage crisis.

The Dallas Federal Reserve Bank noted in their 2011 Annual Report on "too big to fail" financial institutions:

> "Credit default swaps fed the mania for easy money by opening a casino of sorts, where investors placed bets on—and a few financial institutions sold protection on—companies' creditworthiness... Greed led innovative legal minds to push the boundary of financial integrity with off-balance-sheet entities and other accounting expedients. Practices that weren't necessarily illegal were certainly misleading—at least that's the conclusion of many post crisis investigations."[21]

Such similarities can now be seen with shale operators.

In this case, Wall Street once again led the mania by enlisting its army of sell-side analysts to promote shale production. In August of 2011, Neal Anderson of Wood Mackenzie had this to say about the investment community and shale exploration:

> "It seems the equity analyst community has played a key role in helping to fuel the shale gas M&A market, acting as chief cheerleaders for shale gas plays."[22]

A shale company's worthiness was extolled through analyst "buy" recommendations. Investors placed their bets and speculation drove natural gas prices in 2008 to artificially high levels far beyond historical prices. Investors leaped in with reckless and emotional abandon because of the exuberance. The price of natural gas hit a high of $13.50/mcf in 2008, more than twice the historical average of $5-6/mcf. Further, and even more troubling, operators and investors began to refer to such artificially high prices as though they were the new norm. In fact, drilling decisions were made based on an erroneous assumption that prices would never move back to historical levels.

High hopes, no transparency

All overtly exuberant market cycles have one common characteristic: they are overwhelmingly emotional rather than rational in their decision-making processes. This always poses a danger. In hindsight, the mortgage bubble was predicated on years of financial exuberance. A general outlook of "this party can go on forever" had taken hold. New technologies emerged which allowed for much more sophisticated financially engineered products. Creativity abounded on Wall Street. Products were deliberately engineered to reduce the lenders' risk. Or so it was thought.

Banks no longer held on to mortgages. Instead it became lucrative to make loans, package the mortgages, have a ratings agency pronounce it a safe investment and then flip them to investors, thereby collecting large fees. This is not unlike the land grab which shale operators engaged in by leasing millions of acres of land, drilling a handful of wells and pronouncing the field "proved up" and thereby a "safe" investment, and then flipping such parcels to the highest bidder. This exercise quickly drove prices up.

Before the mortgage crisis, once the extent of the appetite was realized for credit default swaps, representatives of the capital markets worldwide embraced the new products. The fees generated were immense. It was similar with shale. Land was bid up to ridiculous prices with signing bonuses reaching nearly $30,000/acre and leases on unproven fields being flipped for as much as $25,000/acre, multiples of original investment.[23] There seemed an unending appetite.

In another example of parallels: credit default swaps were not traded on any exchange, so transparency became a paramount issue. It proved very difficult to accurately measure the underlying fundamentals with such a lack of transparency. It was the same with shales. Due to the new technology of hydrofracture stimulation, shale results could not be verified for a number of years. There simply was not enough historical production data available to make a reasonable assessment. It wasn't until Q3 of 2009 that enough production history on shale wells in the Barnett had been filed with the Texas Railroad Commission that well performance could be checked.[24] What emerged was significantly different from the operators' original rosy projections. Of further interest is the fact that once numbers could begin to be verified in a play, operators sold assets quickly. This has followed in each play in the U.S. as it matured. The dismal performance numbers were recognized as a potential drag on company share prices. A good example would be the operators in the Barnett play in Texas. The primary players were Chesapeake Energy(significant portion of assets sold or jv'ed), Range Resources (all Barnett assets sold), Encana,(all Barnett assets sold) and Quicksilver Resources (company attempting to monetize all Barnett assets via MLP or asset sale since 2011. In that time frame, stock has plunged from about $15/share to $2.50/ share).

The issue of well performance disclosure has continued to mask problems in shale production. States such as Pennsylvania and Ohio do not release well performance data on a timely basis, which makes it very difficult to get a true picture of actual well history.

Purposeful complexity, willful ignorance

Many highly complex financial products were at the very heart of the mortgage crisis. Interestingly, they have also found a place in shale production.

For instance, in May 2011, Barclays Capital came up with an innovative structure through a volumetric production payment (VPP) which allowed a broader base of investors into a shale deal with Chesapeake Energy. According to Risk, March, 2012:

> "The main challenges in putting together the Chesapeake VPP deal were getting the structure right and guiding the rating agencies and institutional investors—who did not necessarily have deep familiarity with the energy business—through the complexities of natural gas production."[25]

Once again, investors are encouraged into investments in an off-balance sheet transaction which is inherently complex and which they admittedly do not have familiarity with. Further, by Barclay's own admission the ratings agencies needed to be “guided” to fully understand the complexities of the deal.

During the lead up to the mortgage crisis, financial products were actually reverse-engineered to pass the ratings agencies requirements. In addition, lenders sought out clients who were not qualified to assume mortgages.

It is also interesting to note that before the mortgage crisis, Congress encouraged the government agencies of Fannie Mae and Freddie Mac into becoming the largest buyers of mortgage securities, a move that in hindsight was ill-conceived.[26]

Recently some members of Congress have begun advocating the perceived benefits of shale gas and shale oil exportation. It is a controversial position, however, and one which is not necessarily shared by all industry insiders more well-versed in resource potential than Congressional representatives.

In August, 2012, the *New York Times* reported:

> “Last week, more than 40 members of Congress urged President Obama to move forward with approval, citing the benefits of free trade and the prospect of creating more jobs as demand for exports leads to growth in gas production.”[27]

And yet, in February, 2012, Lee Raymond, former CEO ExxonMobil stated:

> “Even if you get past the politics, you have to test whether or not the resource base is sufficient [for exportation]...It’s going to be a little while before people are really confident that there is going to be a sufficient amount of gas for 30 years...I’m frankly not sure that we have enough experience with shale gas to make the kind of judgment you’d have to make.”[28]

In addition, John Hofmeister, the former chief of U.S. operations for Shell, stated in September 2012, “Unless something seriously changes in the next five years, we'll be standing in gas lines because there won't be enough oil to go around.”[29]

The drilling treadmill

Mr. Hofmeister said he believes forecasts also understate the “decline” rate of shale fields. The hydrocarbons tend to flow robustly in the first months of drilling, then decline before plateauing at lower levels. Wells have also not been as long-lived as originally forecast.

Mr. Hofmeister concluded that to sustain growth, companies will need to drill many wells at a rate “beyond the capacity of the industry as currently defined...Those who ballyhoo oil shale and say that this will take care of us—no, it won't.”

Mr. Hofmeister is referring to a phenomenon known as the “drilling treadmill” or “exploration treadmill.” Shale extraction requires continuous and prolific drilling programs covering vast acreage in order to maintain a production plateau. Once drilling begins, it must be maintained or production declines rapidly. In other words, shales are heavily reliant on perpetual expansion. This is highly problematic for a fuel which is to be considered a bridge to alternative energies.

According to Dave Hughes, author of a forthcoming report on U.S. shale plays for the Post Carbon Institute:

> “The sweet spots have now been identified, and [initial productivities] are rising as drilling is focused on these areas. It is only a matter of time, however, until available locations in these areas become saturated and the Marcellus moves into middle age... Due to their high decline rates [tight oil] plays require high levels of capital input for drilling and infrastructure development to maintain production levels.”[30]

Hence the drilling treadmill: as production grows, more wells and capital are needed simply to offset the inherent steep declines of shale wells.

Each shale play has essentially followed the same pattern. Operators move into a region and begin a prolific drilling program. Economically, it provides a boost in the short term. The sweet spots are drilled out first as this provides the best possibilities for good wells in addition to good public relations material. In the beginning of a play, individual well productivity appears to climb rapidly. But to extrapolate from this that shale will necessarily provide long term economic stability for a region is highly problematic and unlikely. The older the play, the more difficult it becomes to maintain the production plateau. And the more costly.

Encana's statement from their press release of the sale of all their assets in the Barnett Shale of North Texas illustrates this point quite well:

> “We’re going to focus our energies on our higher growth properties that are at earlier stages of development and have more opportunity for growth...The Barnett is not the best place for Encana to put its money.. It’s a mature area and the sweet spots have been drilled out.”[31]

Each shale play in the U.S. has demonstrated such sweet spots and steep declines. In spite of industry promises of long-term stability, shale plays are known within the industry as statistical plays. Dr. John Lee, the architect of the SEC's rule change for oil and gas and a well-respected petroleum engineer stated:

> “It is sometimes said...that 20% of [shale] wells carry a project; the other 80% can easily be uneconomic.”[32]

This adds further problems for shale developers because with so many uneconomic wells it becomes that much harder to keep production flat. Furthermore, all new wells being drilled will follow this 80/20 estimation.

For illustrative purposes, industry would need to drill 561 new wells per year just to offset declines at present using the latest type curve for the Marcellus. Because the Marcellus is a relatively new play, currently there are 1244 new wells being added each year. Thus production is still in the growth phase. As production grows, so does the number of new wells needed to offset declines.[33]

This business model is not sustainable. Once the sweet spots are drilled out, operators begin to sell assets because the costs of trying to maintain a flat production profile are enormous. This corroborates Mr. Hofmeister's statements above.

The cost of maintaining a flat production profile is staggering. For instance, according to Dave Hughes, the cost of a Marcellus well is about $4.5 million, which translates to $2.5 billion each year to offset declines (excluding leasing and infrastructure costs). This is lower than the Haynesville at $7 billion (to maintain a flat production profile) and the Barnett at $5.3 billion.[34]

Financial co-dependency

In the lead up to the financial crisis, Wall Street bundled mortgages of different quality, packaged them and sold them off to investors. Through reverse-engineering to meet the ratings agency's stipulations, they managed to get approximately 80% of these loans classified as investment grade. These were inherently complex financial products. Due to the tremendous appetite for the securities, it then became expedient to originate mortgages. The more mortgages of any quality available, the more that could be packaged and sold to hungry investors. One study found that 68% of all residential mortgages had been originated by a mortgage broker prior to the crisis.[35]

In much the same manner, the shale operators moved into areas and began leasing acreage. Companies vied with one another to bundle vast acreage. Each play followed the same game plan: operators would originate leases and then bundle them.

Aubrey McClendon, CEO of Chesapeake Energy, stated unequivocally in a financial analyst call in 2008:

> "I can assure you that buying leases for x and selling them for 5x or 10x is a lot more profitable than trying to produce gas at $5 or $6 mcf."[36]

This sort of promotion was not peculiar to Chesapeake Energy. In January, 2012, Bloomberg reported:

> "Surging prices for oil and natural gas shales, in at least one case rising 10-fold in five weeks, are raising concern of a bubble as valuations of drilling acreage approach the peak set before the collapse of Lehman Brothers Holdings Inc."[37]

Bundling leases was highly profitable business in much the same manner as bundling mortgages. Operators and sell-side analysts, although not necessarily in admitted collusion, would froth the markets with heady forecasts. Operators would then drill a few wells and declare the field as “proved up”. There was, however, uncertainty as to whether the fields truly were “proved up”.

In January, 2012, Bloomberg noted:

> “Chinese, French and Japanese energy explorers committed more than $8 billion in the past two weeks to shale-rock formations from Pennsylvania to Texas after 2011 set records for international average crude prices and U.S. gas demand. As competition among buyers intensifies, overseas investors are paying top dollar for fields where too few wells have been drilled to assess potential production…”[38]

Moreover, production targets added further financial strain to ailing balance sheets.[39] They also added much more gas to already burgeoning supply capacity. This in turn drove prices lower still. In January, 2012, prices plunged under $3/mcf. Break even costs for shale wells were averaging about $4-6/mcf, so operators were facing significant shortfalls.[40]

And yet, the banks who were generating large fees off shale company transactions were still rating these same companies as “buys” to the average investor.

To give an example, Chesapeake Energy announced the sale of assets and a notes offering last February. Bank of America/Merrill Lynch, Morgan Stanley, Deutsche Bank, Goldman Sachs, Jeffries and Royal Bank of Scotland were the banks involved in the deals.

In the days and weeks leading up to the announcements, these same banks issued recommendations on Chesapeake Energy.[41] They were as follows:

Bank of America/Merrill Lynch	Buy
Jeffries and Co.	Buy
Morgan Stanley	Overweight
Goldman Sachs	Hold
Deutsche Bank	Neutral
Royal Bank of Scotland	N/A

At the same time of this announcement, other analysts at institutions which did not stand to gain fees from these transactions had an opposite view of the prospects for Chesapeake Energy.

On February 15, 2012, an analyst in *Deal Pipeline* stated, “Chesapeake is in serious trouble…Its Enron style of media hype, off-balance sheet accounting and excessive leverage has finally caught up with them. The end appears to be close.” [42]

Zacks Equity Research placed Chesapeake Energy on bankruptcy watch with an Altman Z score of .84. Anything below 1.80 is considered to be at high risk for bankruptcy.[43]

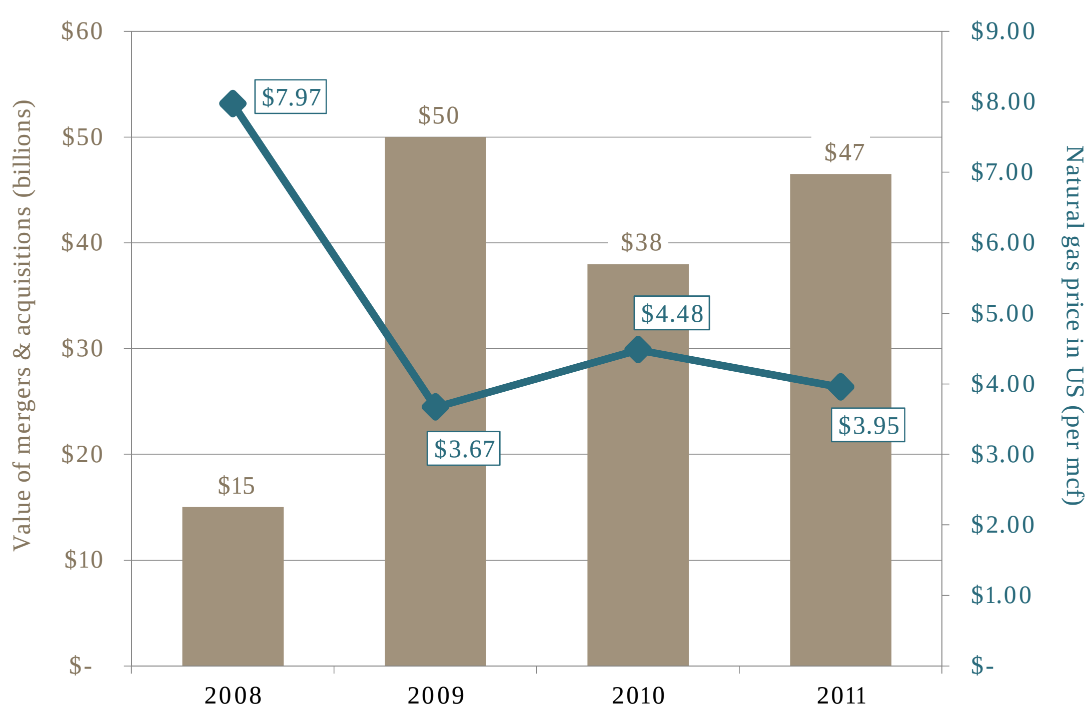
Over the next two months, numerous problems came to light regarding Chesapeake. Reuters broke a story disclosing $1.1B in undisclosed notes.[44] Then it was uncovered that Chesapeake CEO Aubrey McClendon was running a $200 million hedge fund from Chesapeake corporate offices in Oklahoma City trading in the very commodities which Chesapeake produced.[45] Both the Department of Justice and the SEC opened investigations.[46] In Q2-3 2012, the company wrote off over $2B in shale assets and have been forced to sell over $10B in assets just to stay afloat with more asset sales pending and expected.[47] The share price plunged over 40% in a matter of weeks.

Ralph Eads of Jefferies, one of Chesapeake Energy's primary investment banks, was quoted in the *New York Times*, October, 2012, admitting to talking up prices and perhaps even alluding to hoodwinking the Majors who bought shale assets:

> "Typically we represent sellers, so I want to persuade buyers that gas prices are going to be as high as possible...the buyers are big boys—they are giant companies with thousands of economists who know way more than I know. Caveat emptor."[48]

According to KPMG, shale gas accounted for $46.5 billion in deals in the U.S. alone in 2011.[49] The mergers and acquisitions market for shale assets exploded in the prior two years directly in sync with the downward descent of natural gas prices (see chart, below). In much the same way as mortgage backed securities bolstered the banks' profits before the downturn, energy M&A had now become the new profit center within these banks.

Value of Mergers & Acquisitions Compared to Natural Gas Prices, 2008-2011



Data: IHS Herold; Energy Information Administration.

The demise of the NGL market

As the drilling treadmill became more apparent, operators attempted to divert attention away from the plummeting natural gas price by focusing intently on liquids-rich production, announcing concentration on wet gas areas of shale plays. This was an obvious ploy to salvage the appearance of profitability and continue to meet the production targets so necessary for share price appreciation. In effect, however, this focus wreaked havoc on the natural gas liquids (NGL) market in the same way it had eroded natural gas prices.

Analysts did, in fact, recognize the possibility of a glut in NGLs. This would, of course, have placed additional psychological and financial pressure on operators to consider selling assets or seeking joint venture partners, even mergers, which the banks could then effect. About the NGL market, Bank of America/Merrill Lynch stated:

> "Perhaps more importantly, we also find that the weak fundamentals in the NGL market hold some interesting repercussions for natural gas. Although returns on NGL production are currently protecting natural gas producers from low natural gas prices, eventually the glut in the NGL market could catch up with them. Lower NGL prices could then quickly translate into a slowdown in liquid drilling programs if margins contract or turn negative even. In other words, while drilling for NGLs is currently producing a chunk of natural gas at zero cost, the surpluses in the NGL market could come to haunt producers."[50]

That is precisely what happened. In an obvious effort to appease their bankers and shareholders, operators had overproduced yet again and driven prices of NGL's to new lows.

In May, 2012 Reuters reported:

> "U.S. natural gas drillers, stung by decade-low gas prices, have flooded into so-called liquids-rich plays, but the surge in natural gas liquids (NGLs) output that was meant to salvage profitability is leading to a new glut."[51]

By July, 2012 Reuters reported:

> "U.S. oil and gas companies that have depended on natural gas liquids to lift profits may now have to rein in spending or sell some assets after the industry drilled its way into a glut of natural gas liquids."[52]

And the sale of assets began.

An interesting example of NGL overproduction is Range Resources, who heavily touted their emphasis on liquids-rich production. In their earnings call Q4 2011, it was stated:

> "The first is the super-rich Marcellus...Given the high price of oil versus the current low price of gas, this super-rich play enhances the value of our Marcellus economics."[53]

Range management went on to say:

> "The higher volumes are not only the result of drilling in the higher BTU area, but are also the result of drilling longer laterals and completing them with more frac stages. We've also experimented with reduced cluster spacing, decreasing the frac interval from 300 feet to 150 to 200 feet; all of this looks very promising. Once we extract ethane beginning late next year, this will further enhance the economics."[54]

Note that the additional BTUs gained from liquids "are also the result of drilling longer laterals and completing them with more frac stages." This translates into higher costs to extract liquids for which the market was already becoming glutted. Improving the economics in this way has proven to be wishful thinking as Range announced disappointing margins for the last five quarters with a loss of $53.8 million in 3Q 2012.[55]

Oil and gas companies with material exposure to NGLs include Range Resources, Quicksilver Resources Inc., Forest Oil Corp and Pioneer Natural Resources.

Foreign entities buy up U.S. shale

Beginning in 2009, the number of M&A deals within the shale market began to explode. Initially, many transactions involved foreign investors such as Chinese, Korean, French and Norwegian companies looking to purchase U.S. shale assets. The banks effected these transactions for large fees.

CNOOC, a Chinese oil and gas company, paid $1.1 billion for 33.3% of Chesapeake Energy's Eagle Ford acreage and agreed to fund another $1.1 billion of the drilling costs. It is estimated that Chesapeake cleared approximately $10,237 per acre, a significant multiple of original cost.[56] Anadarko, too, has entered into a joint venture with the Korea National Oil Corporation, which agreed to pay $1.55 billion for a 33% share of Anadarko Petroleum's acreage in the Maverick Basin in Texas.[57]

In addition, BHP Billiton, a large Australian mining multinational agreed to acquire Petrohawk Energy Corp, for approximately $15.2 billion paying a considerable premium of approximately 65% to Petrohawk's prior day close.[58] In addition, BHP paid Chesapeake Energy approximately $4.75 billion for its Fayetteville shale assets only to write down in excess of 50% of their value a mere 18 months later.[59] Many other deals were consummated during this time.

By Q2-Q3 2012, shale asset write-downs began in earnest.

Massive write-downs of shale assets

In the lead up to the mortgage crisis, there were hints of things to come in the form of asset write downs. Unfortunately, very few were heeded. In February 2007 HSBS booked a loss on mortgage assets of $10.5B.[60] In Q3, UBS announced a loss of $690m.[61] In January of 2008, Citigroup announced a loss for the prior quarter of $9.8B.[62] Other write-downs occurred, in addition to Chapter 11 filings for some companies.

Similar hints have been emerging with regard to shale. In May 2012, *Forbes* reported the following:

> "Chesapeake Energy shares closed down 14% today on wording in an SEC filing that the company might have to write down the value of its assets because of record low gas prices and might have trouble meeting its obligations under bond covenants...Although such write-downs don't affect the company's cash balance, they do erode the value of the assets carried on the company's balance sheet. This asset value directly impacts the amount of debt leverage the company can maintain."[63]

In Q3 2012, as predicted, further deterioration occurred for Chesapeake. The company took an additional and considerably larger impairment charge of $2.02B on it shale assets.[64]

Further, in July, 2012, ITG Investment Research, at the request of several large institutional investors, engaged in a study which ultimately questioned Chesapeake Energy's (CHK) claims of booked reserves. ITG gathered its well data from public sources such as production history filed with the Texas Railroad Commission. They concluded that a significant portion of Chesapeake reserves in the Barnett "have no positive value, heralding a potential writedown in our opinion."[65]

Through July and August 2012 the bad news kept pouring in. According to Reuters:

> "Encana said it had recorded a US$1.7 billion non-cash after-tax impairment charge resulting primarily from the decline in 12-month average trailing natural gas prices."[66]
>
> "Natural gas-focused producer Quicksilver Resources Inc. posted a second-quarter loss on a big impairment charge as weak prices for natural gas and natural gas liquids lower the value of the company's assets...Quicksilver said its results were hurt by a $992 million non-cash impairment of oil and gas properties due to lower prices."[67]

According to the *Financial Times* of London:

> "British Petroleum (BP) said Tuesday it is taking an impairment charge of US$2.11 billion, primarily relating to its U.S. shale gas assets."[68]
>
> "BHP Billiton (BHP) blamed a glut of gas supply in the US for a US$2.84B impairment charge against the value of its Fayetteville gas assets, which it acquired for US$4.75B 18 months ago."[69]

According to Bloomberg:

> “BG Group, the U.K.’s third-largest oil and gas producer, wrote down $1.3 billion on its U.S. shale fields...”[70]

Further impairments are expected in the coming quarters.

Although companies claim that such charges are not reflective of the fair value of the assets, this is highly questionable given the significant reserve downgrades which the USGS has assigned to all shale plays in the U.S. The fact that some of these companies would have found themselves in collateral default had they accurately reflected their reserves on the books is also extremely troubling.

In view of these significant impairments, deal-making appears to have reached saturation point as of Q3 2012.

According to PriceWaterhouseCoopers, companies with acreage in the Marcellus had enjoyed approximately $32 billion in merger and acquisition deals since the beginning of 2010. The third quarter of 2012, however, was the first in that period with no deals at all. Activity fell to zero.[71]

Given the poor performance of prior shale deals, it appears that investors are becoming more cautious. According to Reuters:

> “...one investment banker said that there is currently ‘a little bit of “JV fatigue” ’ in the energy industry, noting that some companies might be wary of linking up with the precariously positioned Chesapeake... ‘I think that's very true as it relates to Chesapeake, which has a bit of an asterisk beside their name at this point. I think people have found their experience with Chesapeake has been unrewarding...’ ”[72]

And yet, Chesapeake has been continuously touted by industry and its investment banks to have some of the very best shale acreage in the business.

Companies start pulling out

In spite of all the hype surrounding shale production, it is interesting to note the recent behavior of other industry players with regard to shale assets.

In October, 2011, Norse Energy announced it was putting its 130,000 acres in New York State's portion of the Marcellus up for bid. Over a year later, in December, 2012, Norse Energy had not been able to sell the assets. This, coupled with high levels of debt, forced Norse to declare bankruptcy under Chapter 11.[73]

Although there is a moratorium at present in New York State with regard to hydrofracking, it is generally assumed that fracking will be allowed at some point in the state. The fact that no other energy company was interested in picking up these assets, however, indicates a distinct lack of confidence in the assets overall.

Other companies have also begun letting their leases expire in New York with no intention to renew. For instance, Anschutz Exploration recently announced that they would not seek to renew leases. According to the *Denver Business Journal* in December 2012:

> "Anschutz Exploration isn't alone. Other companies are letting their oil and gas leases on property in the state lapse because a drilling moratorium, coupled with the threat of tougher regulations, has made New York less attractive for gas operations."[74]

As stated at the beginning of this report, industry relies heavily on fewer business hurdles to effect their drilling programs. Margins are simply too thin in shales and the well performance too poor to justify investment in wells with added regulatory and environmental costs.

It is also interesting to note that in the Utica shale, which Chesapeake Energy CEO Aubrey McClendon boasted in the early days was "the biggest thing to hit Ohio since the plow," operators have experienced difficulties getting joint venture partners for drilling. According to Bloomberg, September 2012:

> "PDC Energy Corp. didn't receive a high enough bid from would-be joint-venture partners for an interest in its Utica holdings and will develop the acreage on its own..."[75]

Information is emerging that the Utica wells are not performing up to expectations. Financial analysts, upon examining the initial well results released by the State of Ohio, characterized them as "underwhelming". According to Reuters:

> "Even Chesapeake has muted its trumpet...In an SEC filing this May, the company said it was planning to drill a significant number of wells in Utica's 'oil window' over the rest of this year, referring to an area that is expected to hold mostly oil. Three months later it said it 'continues to focus on developing the wet gas and dry gas windows,' with no mention of oil. Chesapeake declined to comment on the change in description."[76]

In the Bakken shale of North Dakota, which is primarily an oil shale play, plans to build a pipeline to carry the oil to a large storage facility in Cushing, Oklahoma were recently abandoned. According to Energy and Capital, November 2012:

> "Oneok Inc. (NYSE: OKE) experienced a recent setback after its subsidiary, Oneok Partners LP (NYSE: OKS), failed to secure enough oil producers to justify developing a $1.8 billion Bakken pipeline."[77]

This is of particular interest. Pipeline projects are expensive and require that a steady and consistent stream of gas or oil can be counted on for a long period of time in order to recoup initial capital outlay. Once initial capital is recouped, however, they tend to be cash cows. Given the steep decline curves for shale oil that are now readily apparent, it appears that operators recognize that the Bakken will not be a long-term play. As such, they are not prepared to invest the needed capital upfront for a pipeline: again, a distinct lack of confidence in the long term viability of shales.

Costs versus benefits

In the 2012 Summary of Revised Regulatory Impact Statement, the New York State Department of Environmental Conservation (DEC) made the following remark regarding high volume hydraulic fracturing (HVHF):

> "The Department considered the denial of permits for HVHF, but while this alternative would fully protect the environment from any environmental impacts associated with HVHF, it would eliminate the economic benefits."[78]

The purported economic benefits of shale gas and oil have been consistently and egregiously overstated by industry in every shale play to date. While there is some initial economic boost, it has proved short-lived and will almost certainly never cover the peripheral costs of production such as long-term environmental degradation, air quality impacts, aquifer depletion and potential contamination, road repairs and health costs just to name a few. The fact that DEC appears unaware of this is troubling and would seem to suggest that DEC has not done proper due diligence.

Examples abound of industry rhetoric which has not lived up to initial promises. For instance, in 2007 Chesapeake Energy, the largest leaseholder in New York State, issued the following statement in a press release regarding their wells at Dallas-Fort Worth Airport (DFW):

> "Assuming an estimated average recovery of approximately 2.5–3.0 billion cubic feet of natural gas equivalent (bcfe) gross reserves per well, the company believes that up to one trillion cubic feet of natural gas equivalent (tcfe) reserves can be produced from under the airport at an all-in finding and development cost of approximately \$2.00 per thousand cubic feet of natural gas equivalent (mcfe)."[79]

Firstly, based on actual production history in the Barnett shale, Chesapeake wells average 1.5 Bcf, not 2.5–3.0.[80] Secondly, while Chesapeake claimed that finding and development (F&D) costs were in the range of \$2/mcf, independent sources put F&D costs for the Barnett at approximately \$4/mcf.[81]

Not only were the wells in significant decline by year-end 2011—a mere four years after the above-mentioned giddy statements of the press release—Chesapeake also found itself settling a lawsuit with DFW Airport with regard to significant underpayment of royalties.[82]

Further, additional peripheral costs are being borne by taxpayers in states where drilling is prevalent. For instance, according to the *Fort Worth Star Telegram*, July, 2012:

> "...the Texas Department of Transportation (TXDOT) told industry representatives and elected officials on Monday that repairing roads damaged by drilling activity would 'conservatively' cost $1 billion for farm-to-market roads and another $1 billion for local roads."[83]

Another article dated 25 December, 2012, from the Associated Press (AP) stated:

> "The first operating loss in about five years at a north-central Pennsylvania hospital is a sign of the influx of natural gas field workers without health insurance, the facility's CEO said...Jersey Shore Hospital president and CEO Carey Plummer told the *Sun-Gazette* of Williamsport that many subcontractors attracted to the area's Marcellus Shale drilling boom do not cover employees."[84]

It is unlikely that such costs will be borne by the oil and gas industry given the poor performance of the wells and industry's frenzy to sell leases and joint venture shale properties. This will continue to prove problematic for states where shale development has occurred.

Moreover such costs must be factored into the overarching economic equations. Shale development is a highly industrial activity with all that entails. The Texas Commission on Environmental Quality submitted a report to U.S. EPA in December 2011, confirming that drilling activities were contributing 42% more volatile organic compounds then all on-road mobile sources in the Dallas-Ft. Worth region, a significant obstacle to ozone attainment goals.[85] Again, a cost to be borne by the taxpayers rather than the industry that created it.

Every region in the U.S. which has shale development provides a cautionary tale. Economic stability has proved elusive. Environmental degradation and peripheral costs, however, have proved very real indeed.

Conclusion

As documented in this report, emerging independent information on shale plays in the U.S. confirms the following:

- Wall Street promoted the shale gas drilling frenzy, which resulted in prices lower than the cost of production and thereby profited [enormously] from mergers & acquisitions and other transactional fees.

- U.S. shale gas and shale oil reserves have been overestimated by a minimum of 100% and by as much as 400-500% by operators according to actual well production data filed in various states.

- Shale oil wells are following the same steep decline rates and poor recovery efficiency observed in shale gas wells.

- The price of natural gas has been driven down largely due to severe overproduction in meeting financial analysts' targets of production growth for share appreciation coupled and exacerbated by imprudent leverage and thus a concomitant need to produce to meet debt service.

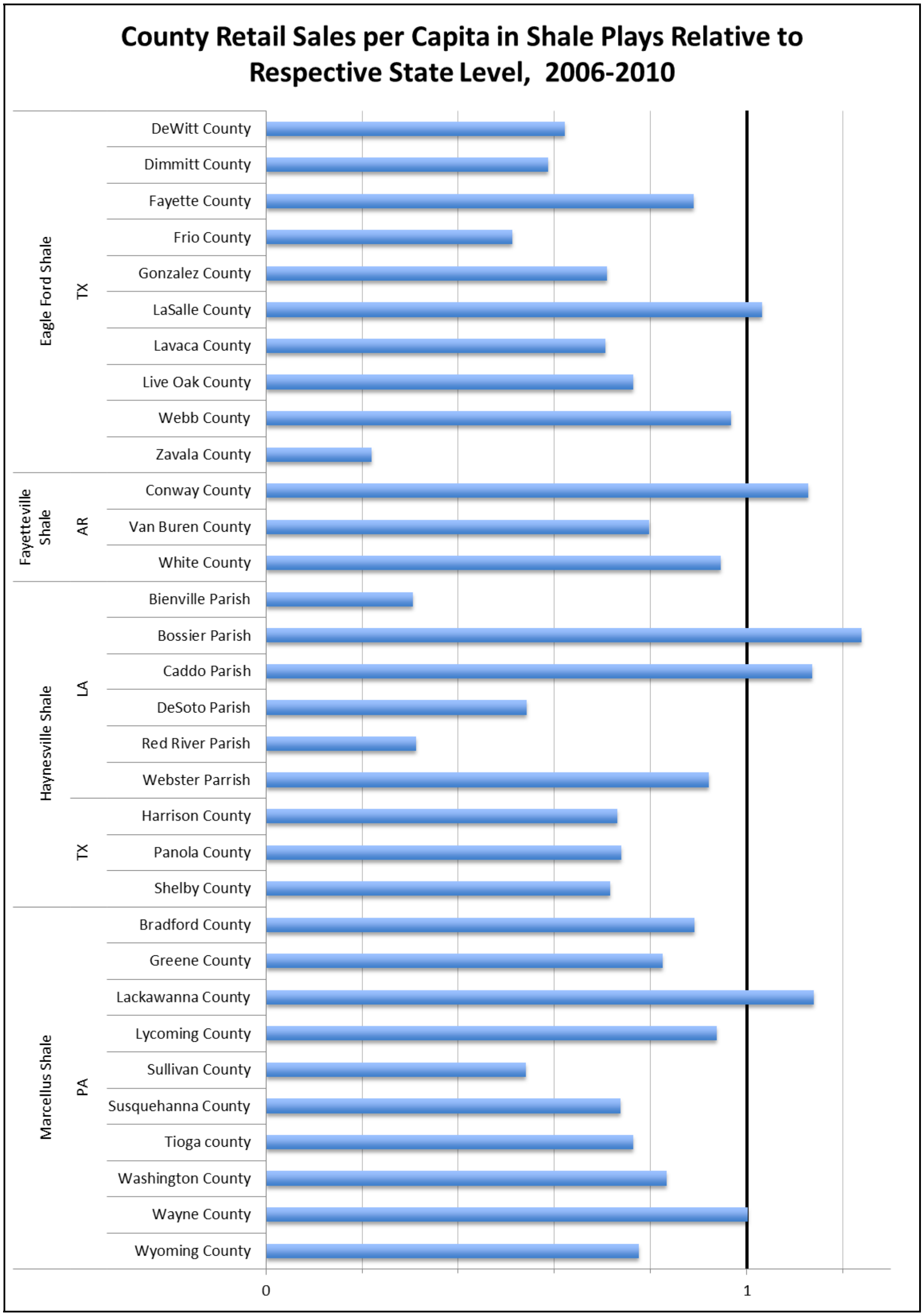
- Due to extreme levels of debt, stated proved undeveloped reserves (PUDs) may not have been in compliance with SEC rules at some shale companies because of the threat of collateral default for those operators.

- Industry is demonstrating reticence to engage in further shale investment, abandoning pipeline projects, IPOs and joint venture projects in spite of public rhetoric proclaiming shales to be a panacea for U.S. energy policy.

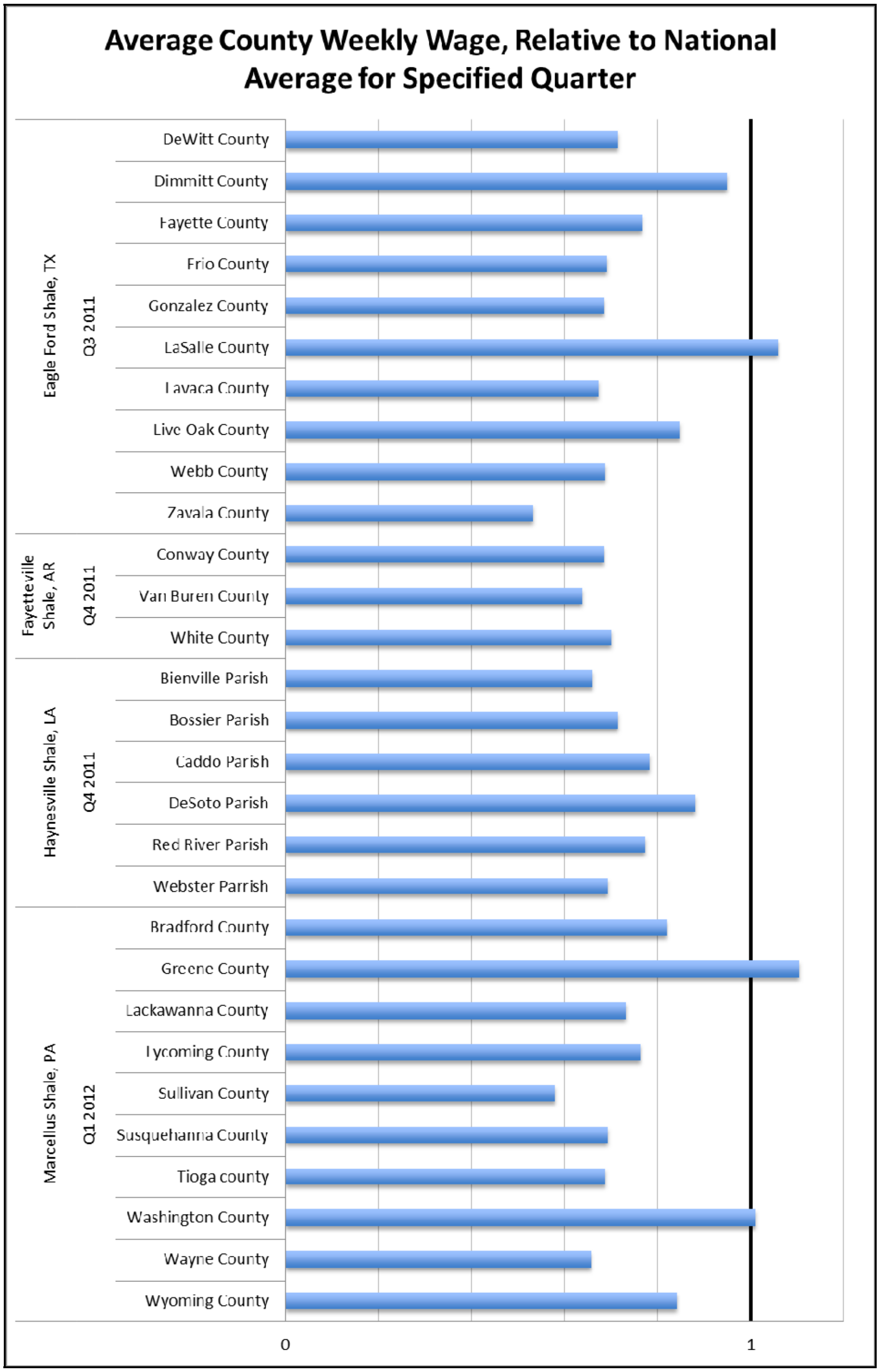
- Exportation is being pursued for the arbitrage between the domestic and international prices in an effort to shore up ailing balance sheets invested in shale assets

It is imperative that shale be examined thoroughly and independently to assess the true value of shale assets, particularly since policy on both the state and national level is being implemented based on production projections that are overtly optimistic (and thereby unrealistic) and wells that are significantly underperforming original projections.

Appendix



Data: U.S. Bureau of Labor Statistics, 2012.



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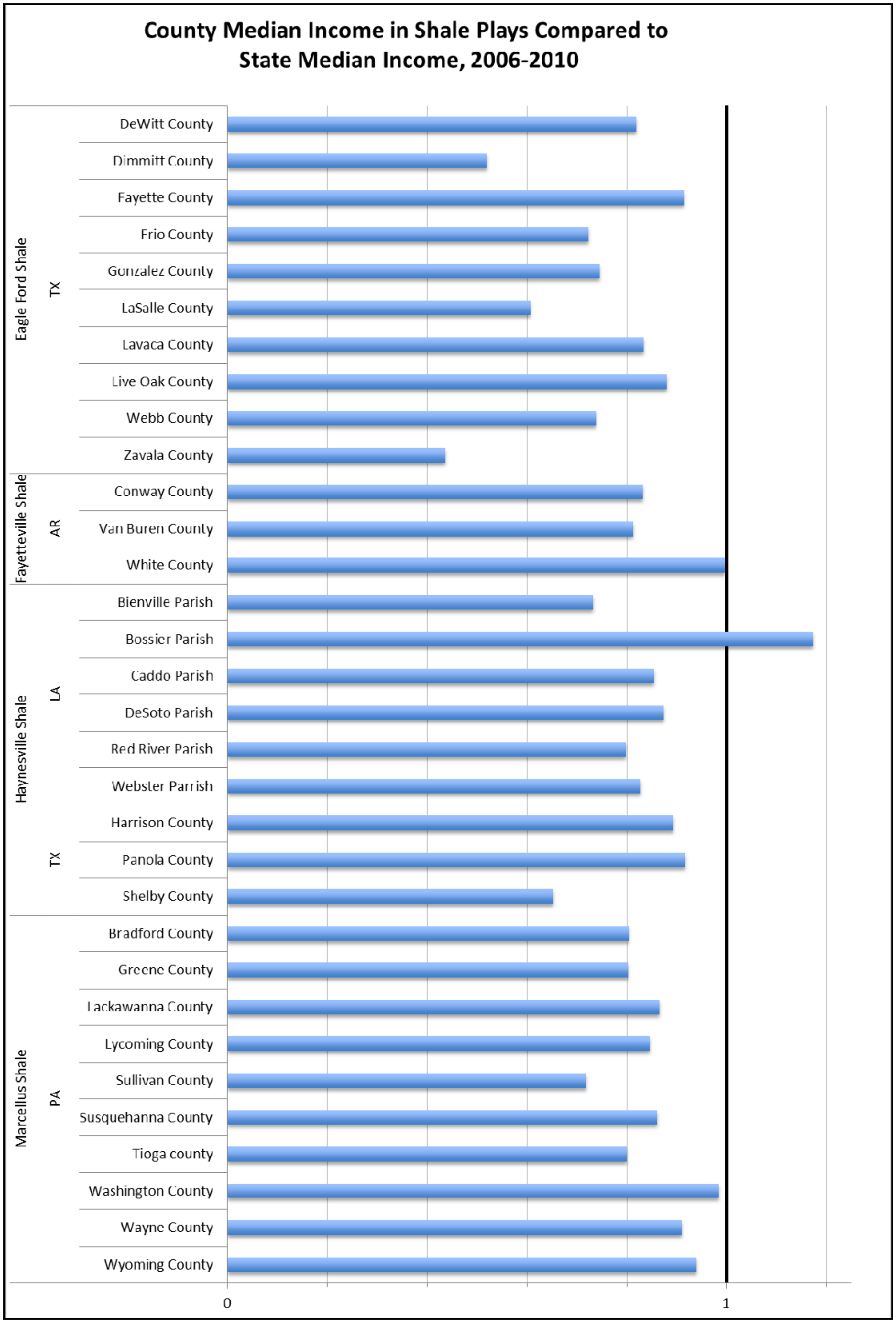

Note: Median household income (MHI), normalized by state.
Data: U.S. Bureau of Labor Statistics, 2012.

About the Author

Deborah Rogers began her financial career in London working in investment banking. Upon her return to the U.S., she worked as a financial consultant for several major Wall Street firms, including Merrill Lynch and Smith Barney. Ms. Rogers was appointed as a primary member to the U.S. Extractive Industries Transparency Initiative (USEITI), an advisory committee within the Department of Interior, in 2013 for a three year term. She also served on the Advisory Council for the Federal Reserve Bank of Dallas from 2008-2011. She was appointed in 2011 by the Texas Commission on Environmental Quality (TCEQ) to a task force reviewing placement of air monitors in the Barnett Shale region in light of air quality concerns brought about by the natural gas operations in North Texas. She is a Member of the Board of Earthworks/OGAP (Oil and Gas Accountability Project). She is also the founder of Energy Policy Forum, a consultancy and educational forum dedicated to policy and financial issues regarding shale gas and renewable energy. Ms. Rogers lectures on shale gas economics throughout the U.S. and abroad and has appeared on MSNBC and NPR. She has also been featured in articles discussing the financial anomalies of shale gas in the *New York Times* (June 2011), *Rolling Stone* (March 2012) and the *Village Voice* (September 2012).

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