

THE GEOPOLITICS OF ENERGY PROJECT

OIL: THE NEXT REVOLUTION

THE UNPRECEDENTED UPSURGE OF OIL PRODUCTION
CAPACITY AND WHAT IT MEANS FOR THE WORLD

LEONARDO MAUGERI



HARVARD Kennedy School

BELFER CENTER for Science and International Affairs

JUNE 2012

Discussion Paper #2012-10

Geopolitics of Energy Project

Belfer Center for Science and International Affairs

John F. Kennedy School of Government

Harvard University

79 JFK Street

Cambridge, MA 02138

Fax: (617) 495-8963

Email: belfer_center@harvard.edu

Website: <http://belfercenter.org>

Copyright 2012 President and Fellows of Harvard College

The author of this report invites use of this information for educational purposes, requiring only that the reproduced material clearly cite the full source: Maugeri, Leonardo. "Oil: The Next Revolution" Discussion Paper 2012-10, Belfer Center for Science and International Affairs, Harvard Kennedy School, June 2012.

Statements and views expressed in this discussion paper are solely those of the author and do not imply endorsement by Harvard University, the Harvard Kennedy School, or the Belfer Center for Science and International Affairs.

Cover image: In this Friday, July 17, 2009 file photo, an Iraqi worker operates valves at the Nahran Omar oil refinery near the city of Basra, 340 miles (550 kilometers) southeast of Baghdad, Iraq. Iraq's central government warned authorities in the semiautonomous Kurdish region on Monday that their oil deals with Turkey must have Baghdad's approval. (AP Photo)

OIL: THE NEXT REVOLUTION

THE UNPRECEDENTED UPSURGE OF OIL PRODUCTION
CAPACITY AND WHAT IT MEANS FOR THE WORLD

LEONARDO MAUGERI



HARVARD Kennedy School

BELFER CENTER for Science and International Affairs

JUNE 2012

ACKNOWLEDGEMENTS

It is always difficult to keep track of the individuals who contributed to a research work like this, whether by a quick exchange of opinions, data, comments, or a well-articulated set of suggestions.

I have an abiding debt to many people of different oil companies who helped me get data and interpret them correctly. Yet the list of them is too long to be reproduced here.

I have a debt of gratitude for the help and advice I received from some professors of the Harvard Kennedy School and the Belfer Center for Science and International Affairs, starting with Meghan O’Sullivan who invited me to join the Geopolitics of Energy Project at the Harvard Kennedy School and supported me during my first period here, and others along with her, who agreed to review this paper in spite of their busy schedule: Graham Allison, Henry Lee, and William Hogan. I also owe a special gratitude to Donald Paul, Bijan Mossavar-Rahmani, and Jonathan Hine, Jr. who also read the paper and suggested important clarifications and additions.

If I failed to capture the depth of the observations of my reviewers or to correct some point I alone am to blame.

I owe a special thanks to BP for its funding of the Geopolitics of Energy Project that made my study possible.

I have a debt towards Leah Knowles, who carefully edited the final version of the paper, and Amanda Sardonis, who took care of putting the paper in its final form and provided the policy brief. As always, I could never have begun or finished this work without the sweet support of my wife Carmen.

For all the help that others gave me, they are certainly not party to any mistakes I might have made. Even when they expressed some doubt about certain notions or data, they always left me free to consider or reject their points. I therefore remain the only person responsible, in every way, for the ideas expressed in this paper – along with any mistakes it might contain.

TABLE OF CONTENTS

List of Abbreviations and Terms	i
Executive Summary	1
Introduction	8
I. A Global View	11
1. Not Running Out of Oil: How Hydrocarbon Resources Evolve	11
2. Methodological Problems in Evaluating Future Supply	16
3. A Mounting Wave of Underestimated Supply	20
4. Adding New Production to Old	32
II. The U.S. Shale/Tight Oil	41
5. From Shale Gas to Shale and Tight Oil	41
6. Herald of the Revolution: the Bakken Shale case	46
7. A Broader View of the U.S. Shale/Tight Oil Potential	51
8. The Problems Looming over U.S. Shale Oil	55
9. Shale and Tight Oil & Gas versus the Environment	58
III. Conclusions	64
10. What is Really Ahead?	64
Appendix A	70
A Note on Methodology	70

LIST OF ABBREVIATIONS AND TERMS

Barrel – 42 gallons of oil (about 159 liters)

Bcf – Billion cubic feet

Bd – Barrels per day

BOE – Barrels of oil equivalent. It assumes that one 42 gallon barrel of oil is equivalent to 5,800 cubic feet of natural gas, that it holds the same energy content of one barrel of standard crude oil.

BOEd – Barrels of oil equivalent per day

Btu – British thermal unit

CERA – Cambridge Energy Research Associates

Cheap oil – The expression “cheap oil” has not exact boundaries. Generally, in the oil literature it is used in reference to the cheap oil prices prevailing over the second half of the 20th Century, when oil price in real terms (2000 U.S. dollars) ranged between \$ 20-30 per barrel, with some noteworthy exception (such as during the period of the oil shocks in the 1970s and early 1980s, when the price of oil largely exceed \$ 100 per barrel in real terms).

CO₂ – Carbon Dioxide

Depletion rate – The natural decline of an oilfield’s output after years of production. It could be partially offset by reserve growth.

DOE – (U.S.) Department of Energy

EIA – (U.S.) Energy Information Administration

EOR – Enhanced Oil Recovery

EUR – Estimated Ultimate Recovery

GDP – Gross Domestic Product

GtL – Gas to Liquids

IEA – International Energy Agency

IOCs – International Oil Companies

IOR – Improved Oil Recovery

IRR – Internal Rate of Return

MEND – Movement for the Emancipation of the Niger Delta

MBtu – Million British thermal units

Mbd – Million barrels per day

MIT – Massachusetts Institute of Technology

NDDMR – North Dakota Department of Mineral Resources

NGLs – Natural Gas Liquids. These include ethane, propane, butane, pentane, and natural gasoline. Like crude oil, they are considered as part of oil production and oil production capacity.

OECD – Organization for Economic Cooperation and Development

OPEC – Organization of Petroleum Exporting Countries. It is formed by 12 countries: Algeria, Angola, Ecuador, Iran, Iraq, Kuwait, Libya, Nigeria, Qatar, Saudi Arabia, United Arab Emirates, and Venezuela.

OPP – Original oil in place. The total estimated amount of oil in an oil reservoir, including both producible and non-producible oil. Because of reservoir characteristics and limitations in petroleum extraction technologies, only a fraction of this oil can be brought to the surface, and it is only this producible fraction that is considered to be *reserves*. The ratio of producible oil reserves to total oil in place for a given field is often referred to as the *recovery factor*.

PADD – Petroleum Administration for Defense Districts. These districts are the geographical aggregations used by the US government to collect petroleum data. PADD 1 is the east Coast region, PADD 2 is the Mid-Continent and Midwest, PADD 3 is the Gulf Coast region, PADD 4 is the Rocky Mountain region, and PADD 5 is the West Coast.

SPM – Single Point Mooring (a floating oil export terminal)

Spare capacity – The difference between the total oil production capacity (usually referred to a country, or the world) that can be reached within 30 days – and sustained for 90 days – and the actual production. As a consequence, it represents an unused oil capacity that can be activated in a very short period of time.

Reserve growth – The estimated increases in crude oil, natural gas, and natural gas liquids that could be added to existing reserves through extension, revision, improved recovery efficiency, and the discovery of new pools or reservoirs connected with a reservoir that is already producing oil. In other words, it refers to the upgrading of already discovered reservoirs, and not to the discovery of brand-new fields.

U.K. – United Kingdom

Unconventional oil – According to the EIA definition, conventional crude oil and natural gas production refers to oil and gas “produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore”. By converse unconventional hydrocarbon production doesn’t meet these criteria, either because geological formations present a very low level of porosity and permeability, or because the fluids have a density approaching or even exceeding that of water, so that they cannot be produced, transported, and refined by conventional methods.

U.S. – United States

U.S. Mid-Continent – Includes the states of North Dakota, South Dakota, Nebraska, Kansas, and Oklahoma

U.S. Midwest – Includes Minnesota, Iowa, Missouri, Wisconsin, Michigan, Illinois, Indiana, Ohio, Kentucky, and Tennessee

USGS – U.S. Geological Survey

WACC – Weighted Average Cost of Capital

WEC – World Energy Council

WTI – West Texas Intermediate

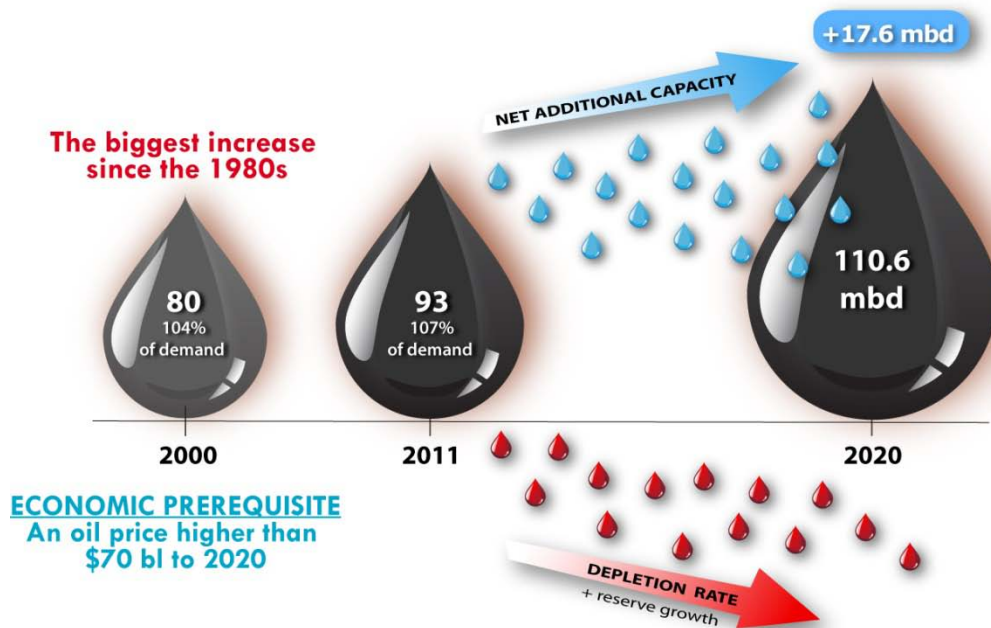
EXECUTIVE SUMMARY

Contrary to what most people believe, oil supply capacity is growing worldwide at such an unprecedented level that it might outpace consumption. This could lead to a glut of overproduction and a steep dip in oil prices.

Based on original, bottom-up, field-by-field analysis of most oil exploration and development projects in the world, this paper suggests that an unrestricted, additional production (the level of production targeted by each single project, according to its schedule, unadjusted for risk) of more than 49 million barrels per day of oil (crude oil and natural gas liquids, or NGLs) is targeted for 2020, the equivalent of more than half the current world production capacity of 93 mbd.

After adjusting this substantial figure considering the risk factors affecting the actual accomplishment of the projects on a country-by-country basis, the additional production that could come by 2020 is about 29 mbd. Factoring in depletion rates of currently producing oilfields and their “reserve growth” (the estimated increases in crude oil, natural gas, and natural gas liquids that could be added to existing reserves through extension, revision, improved recovery efficiency, and the discovery of new pools or reservoirs), the net additional production capacity by 2020 could be 17.6 mbd, yielding a world oil production capacity of 110.6 mbd by that date – as shown in Figure 1. This would represent the most significant increase in any decade since the 1980s.

Figure 1: World oil production capacity to 2020
(Crude oil and NGLs, excluding biofuels)



The economic prerequisite for this new production to develop is a long-term price of oil of \$70 per barrel. Indeed, at current costs, less than 20 percent of the new production does not seem profitable at prices lower than this level.

Only four of the current big oil suppliers (more than 1 mbd of production capacity) face a net reduction of their production capacity by 2020: Norway, the United Kingdom, Mexico, and Iran. For the latter two, the loss of production is primarily due to political factors. All other producers are capable of increasing or preserving their production capacity. In fact, by balancing depletion rates and reserve growth on a country-by-country basis, decline profiles of already producing oilfields appear less pronounced than assessed by most experts, being no higher than 2 to 3 percent on a yearly basis.

This oil revival is spurred by an unparalleled investment cycle that started in 2003 and has reached its climax from 2010 on, with three-year investments in oil and gas exploration and production of more than \$1.5 trillion (2012 data are estimates).

As shown in Figure 2, in the aggregate, production capacity growth will occur almost everywhere, bringing about also a “de-conventionalization” of oil supplies. During the next decades, this will produce an expanding amount of what we define today as “unconventional oils”^{*} – such as U.S. shale/tight oils, Canadian tar sands, Venezuela’s extra-heavy oils, and Brazil’s pre-salt oils.

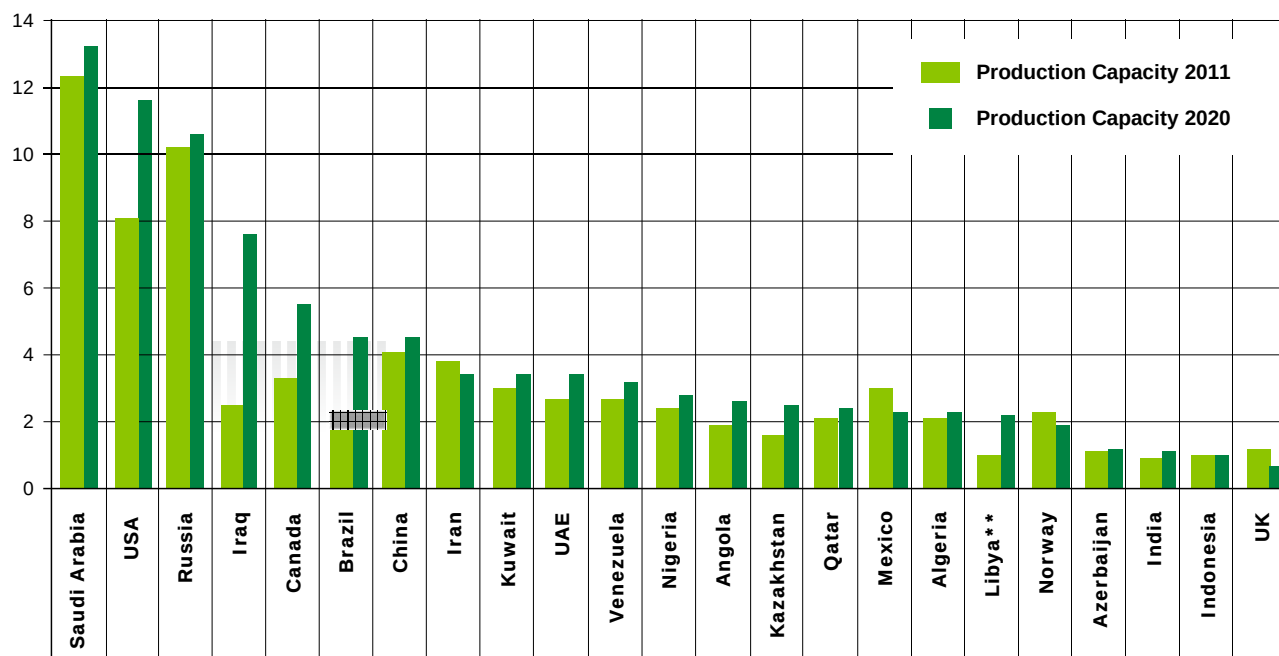
After considering risk-factors, depletion pattern and reserve growth, four countries show the highest potential in terms of effective production capacity growth: they are, in order, Iraq, the U.S., Canada, and Brazil. This is a novelty, because three out of four of these countries are part of the western hemisphere, and one only – Iraq – belongs to the traditional center of gravity of the oil world, the Persian Gulf.

The most surprising factor of the global picture, however, is the explosion of the U.S. oil output.

Thanks to the technological revolution brought about by the combined use of horizontal drilling and hydraulic fracturing, the U.S. is now exploiting its huge and virtually untouched shale and tight oil fields, whose production – although still in its infancy – is already skyrocketing in North Dakota and Texas.

^{*} According to the EIA definition, conventional crude oil and natural gas production refers to oil and gas “produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore”. By converse unconventional hydrocarbon production doesn’t meet these criteria, either because geological formations present a very low level of porosity and permeability, or because the fluids have a density approaching or even exceeding that of water, so that they cannot be produced, transported, and refined by conventional methods.

Figure 2: Country-by-country evolution of oil production capacity to 2020
(First 23 countries)



The U.S. shale/tight oil could be a paradigm-shifter for the oil world, because it could alter its features by allowing not only for the development of the world's still virgin shale/tight oil formations, but also for recovering more oil from conventional, established oilfields – whose average recovery rate is currently no higher than 35 percent.

The natural endowment of the initial American shale play, Bakken/Three Forks (a tight oil formation) in North Dakota and Montana, could become a big Persian Gulf producing country within the United States. But the country has more than twenty big shale oil formations, especially the Eagle Ford Shale, where the recent boom is revealing a hydrocarbon endowment comparable to that of the Bakken Shale. Most of U.S. shale and tight oil are profitable at a price of oil (WTI) ranging from \$50 to \$65 per barrel, thus making them sufficiently resilient to a significant downturn of oil prices.

The combined additional, unrestricted liquid production from the aggregate shale/tight oil formations examined in this paper could reach 6.6 mbd by 2020, in addition to another 1 mbd of new conventional production. However, there remain obstacles that could significantly reduce the U.S. shale output: among them, the inadequate U.S. oil transportation system, the country's refining structure, the amount of associated natural gas produced with shale oil, and environmental doubts about hydraulic fracturing, one of the key technologies for extracting oil

from shale. After considering risk factors and the depletion of currently producing oilfields, the U.S. could see its production capacity increase by 3.5 mbd. Thus, the U.S. could produce 11.6 mbd of crude oil and NGLs by 2020, making the country the second largest oil producer in the world after Saudi Arabia. Adding biofuels to this figure, the overall U.S. liquid capacity could exceed 13 mbd, representing about 65 percent of its current consumption.

The principal difficulty concerning shale gas is the effect of hydraulic fracturing on the environment, which is perceived as contributing to water and land contamination, natural gas infiltration into fresh water aquifers, poisoning of the subsoil because of the intensive use of chemicals, and even minor earthquakes. Even if those problems cannot be eliminated, after more than one million hydraulic fracturing operations in the United States since 1947 (hydraulic fracturing is not a new technology), the evidence shows that only a tiny percentage of these accidents occurred, and that they can be managed with appropriate best practices and adequate enforcement, rather than by over-regulating the activity.

It is worth noting that the U.S. shale revolution cannot be easily replicated in other areas of the world – at least in a short period of time – due not only to the huge resource base of shale/tight oil plays existing in the U.S., but also to some unique features of the U.S. oil industry and market, such as the private ownership of mineral rights, the presence of thousands independent companies – oftentimes small – that historically played the role of pioneering new high-risk, high-reward targets, the huge availability of drilling rigs and other exploration and production tools, a very active financial market that supply money for new ventures. With the exception of Canada, these key features are foreign to other parts of the world, and they make the U.S. and Canada a sort of unique arena of experimentation and innovation.

The analysis in this paper is subject to a significant margin of error, depending on several circumstances that extend beyond the risks in each project or country. In particular, a new worldwide recession, a drastic retraction of the Chinese economy, or a sudden resolution of the major political tensions affecting a big oil producer could trigger a major downturn or even a collapse of the price of oil, i.e. a fall of oil prices below \$70 per barrel (Brent crude).

The oil market is already adequately supplied. Global oil spare capacity (the difference between the world's total oil production capacity that can be reached within 30 days – and sustained for 90 days – and the actual global production), is probably at about 4 mbd,[†] which seems capable of

[†] In the first quarter 2012, average world oil production consistently reached or surpassed 91 mbd. At the same time, consumption has been lower than 89 mbd. This means that huge inventories of oil have accumulated, particularly in Saudi Arabia. For Saudi Arabia, I considered an oil production capacity of 12.3 mbd (slightly less than Saudi official figure of 12.5 mbd), even though part of that capacity (about 800,000 bd) would need at least three months to be activated. During the first quarter 2012, the Kingdom produced more than 10 mbd on average, with a peak of 10.5 mbd in some days. This could mean that the

absorbing a major disruption from a big oil producer such as Iran. In fact, the mere dynamics of supply, demand, and spare capacity cannot explain the high level of oil prices today. At more than \$100 per barrel, the international benchmark crude Brent is \$20 to \$25 above the marginal cost of oil production. Only geopolitical and psychological factors (above all, a major crisis related to Iran) and a still deep-rooted belief that oil is about to become a scarce commodity, can explain the departure of oil prices from economic fundamentals.

Coupled with global market instability, these features of the current oil market will make it highly volatile until 2015, with significant probabilities of an oil price fall due to the fundamentals of supply and demand, and possible new spikes due to geopolitical tensions. This will make difficult for financial investors to devise a sound investment strategy and allocate capital on oil and gas companies.

A hypothetical oil price downturn would have a significant impact, albeit short-lived, if it occurred before most of the projects considered in this paper had advanced significantly - that is, before 2015.

Conversely, if an oil price collapse were to occur after 2015, a prolonged phase of overproduction could take place, because production capacity would have already expanded and production costs would have decreased as expected, unless oil demand were to grow at a sustained yearly rate of at least 1.6 percent for the entire decade.

The opposite could also happen. A sudden rebound of the world economy could strain the equilibrium of oil demand and supply, particularly if accompanied by geopolitical tensions. This

Kingdom's spare capacity – that is, the unused production capacity – over that period has been lower than Saudi Arabia's official target of 2.5 mbd, probably because part of that spare capacity was produced and stored in view of a steep decline in Iranian exports. This analysis is consistent with data from JODI (Joint Organizations Data Initiative, which includes both OPEC and OECD countries), according to which Saudi Arabia had already accumulated 266 million barrels of oil inventories by the end of February. Because of this accumulation of inventories, Saudi Arabia's spare capacity over the first months of 2012 sat at about 1.8 mbd or less. True, other experts deem the Kingdom's effective spare capacity to be lower, because they calculate it against a Saudi production capacity of 11.5 mbd, instead of 12.3 mbd. Even taking this number as the lower limit of Saudi oil potential, this would have left Saudi Arabia with an average spare capacity of about 1.2 mbd during the first quarter, or 1.8 mbd if 12.3 mbd is correct. Also, China's record oil import levels during the last months of 2011 and the first quarter 2012 were aimed at strategic stockpiling, as confirmed by China's National Petroleum Corporation. However, it's not clear how many oil inventories China has built up so far. During that same period, I observed that about 600,000 bd from other countries did not go onstream mainly because of maintenance problems in OECD and Persian Gulf countries. This would make the world production capacity slightly less than 94 mbd, against a consumption of 88.5-89 mbd. To be prudent, I set the world production capacity at the end of 2011 and in the first quarter of 2012 at 93 mbd, slightly less than what I consider to be the actual figure. This means that the world had a kind of spare capacity of about 4 mbd, formed either by pure spare capacity, or by an unusual accumulation of inventories – that represents “silent” production ready to be delivered to the market.

scenario, however, would support an even stronger rush to develop new oil reserves and production.

Whatever the future, the analysis reported in this paper reveals some important points:

- Oil is not in short supply. From a purely physical point of view, there are huge volumes of conventional and unconventional oils still to be developed, with no “peak-oil” in sight. The real problems concerning future oil production are above the surface, not beneath it, and relate to political decisions and geopolitical instability.
- Other things equal, any significant setback to additional production in Iraq, the United States, and Canada would have a strong impact on the global oil market, considering the contribution of these countries to the future growth of oil supply.
- The shale/tight oil boom in the United States is not a temporary bubble, but the most important revolution in the oil sector in decades. It will probably trigger worldwide emulation over the next decades that might bear surprising results - given the fact that most shale/tight oil resources in the world are still unknown and untapped. What’s more, the application of shale extraction key-technologies (horizontal drilling and hydraulic fracturing) to conventional oilfield could dramatically increase world’s oil production.
- In the aggregate, conventional oil production is also growing throughout the world at an unexpected rate, although some areas of the world (Canada, the United States, the North Sea) are witnessing an apparently irreversible decline of the conventional production.
- The age of “cheap oil”[‡] is probably behind us, but it is still uncertain what the future level of oil prices might be. Technology may turn today’s expensive oil into tomorrow’s cheap oil.
- The oil market will remain highly volatile until 2015 and prone to extreme movements in opposite directions, thus representing a major challenge for investors, in spite of its short and long term opportunities. After 2015, however, most of the projects considered in this paper will advance significantly and contribute to a strong build-up of the world’s production capacity. This could provoke a major phenomenon of overproduction and lead to a significant, stable dip of oil prices, unless oil demand were to grow at a sustained yearly rate of at least 1.6 percent for the entire decade.

[‡] The expression “cheap oil” has not exact boundaries. Generally, in the oil literature it is used in reference to the cheap oil prices prevailing over the second half of the 20th Century, when oil price in real terms (2000 U.S. dollars) ranged between \$20 to \$30 per barrel, with some noteworthy exception (such as during the period of the oil shocks in the 1970s and early 1980s, when the price of oil largely exceed \$100 per barrel in real terms).

- A revolution in environmental and emission-curbing technologies is required to sustain the development of most unconventional oils – along with strong enforcement of existing rules. Without such a revolution, a continuous clash between the industry and environmental groups will force the governments to delay or constrain the development of new projects.
- Some of the major geopolitical consequences of the oil revolution include Asia becoming the reference market for the bulk of the Middle East oil, and China becoming a new protagonist in the political affairs of the whole region.
- At the same time, the Western Hemisphere could return to a pre-World War II status of theoretical oil self-sufficiency, and the United States could dramatically reduce its oil import needs.
- However, quasi oil self-sufficiency will neither insulate the United States from the rest of the global oil market (and world oil prices), nor diminish the critical importance of the Middle East to its foreign policy. At the same time, countries such as Canada, Venezuela and Brazil may decide to export their oil and gas production to markets other than the U.S. for purely commercial reasons, making the notion of Western Hemisphere self-sufficiency irrelevant.
- It's also true, however, that over the next decades, the growing role of unconventional oils will make the Western hemisphere the new center of gravity of oil exploration and production.

INTRODUCTION

Quite unnoticed, a big wave of oil production is mounting worldwide, driven by high oil prices, booming investments, private companies' desperate need to restore their reserve, and the misguided but still prevalent perception that oil must become a rare commodity. The year 2012 will likely set a new historic record, with more than \$600 billion to be spent worldwide in oil and gas exploration and production.

For the first time, new areas of the world – from sub-equatorial Africa to Asia and Latin America – are being targeted for mass exploration, and unveiling the potential for significant conventional oil production over the next years.

Furthermore the combination of high oil prices, advanced technologies that were once uneconomical, and restricted access to conventional oil resources in the major oil-producing countries is pushing private oil companies to explore and develop unconventional oils on a broader scale. This effort is concentrated in Canada, the United States, Venezuela, and Brazil.

The U.S. shale/tight oil appears to be a potential “paradigm-shift” for the entire world of unconventional oils.

The unexpected and rapid increase of oil production from the forerunner of shale/tight oil (the Bakken Shale formation in North Dakota) is astonishing: production has grown from a few barrels in 2006 to more than 530,000 barrels in December 2011.¹ This development seems consistent with the best study ever conducted on the geological features and potential productivity of Bakken (Price, 1999), which estimated the maximum Original Oil in Place of the whole formation at more than 500 billion barrels, with a probable recovery rate of about 50 percent. If confirmed, those figures would make Bakken a “game-changer” of the oil business, and one of the largest oil basins ever discovered. And Bakken is only one out of more than twenty shale/tight oil formations in the U.S., that so far have been virtually untouched.

While opinion-makers, decision-makers, the academy, and the financial market seem to be caught up in the “peak-oil” mantra and an excessive enthusiasm for renewable energy alternatives to oil, oil prices and technologies are supporting a quiet revolution throughout the oil world. If this “oil revolution” is true, it may change the way most people think about energy and geopolitics. This paper examines the extent of this revolution.

Part I focuses on the evolution of the global oil production up to 2020, which is articulated in four Sections.

Section 1 describes the fundamental concepts concerning oil resources, reserves, recoverability, depletion, and reserve growth. It shows that our planet still holds huge oil resources yet to be developed or discovered and that no “peak-oil” era is imminent. This section also explains why prices, technologies, and political decisions are key in increasing or decreasing the availability of oil.

Section 2 deals with the major methodological problems and pitfalls affecting the evaluation of the future production of oil, particularly when based on econometric models. The Section also explains the reasons that support a bottom-up analysis of future production, based on a global field-by-field evaluation of all investments underway in the world and their targeted production—like the one carried-out in this paper. Although not exempt from a high margin of error and arbitrary assumptions, a field-by-field analysis more precisely assesses the developing supply over a ten year period.

Section 3 details the initial results of the field-by-field analysis conducted for this paper. It reports the assessment concerning the big wave of new production of under-development or re-development, showing both the *additional unrestricted production* (the additional production targeted by all current investments, with no associated risk factor) and the *additional adjusted production* (that is the *additional unrestricted production* considering risk factors) due to come on board by 2020. The evolution of oil production from already producing fields is not considered in this section (it will be taken into account in *Section 4*) to give the reader a precise sense of all new oil developments occurring worldwide. A special focus is devoted to data concerning the 11 most relevant countries in terms of future production growth.

Section 4 completes the analysis reported in Section 3, including the additional adjusted production (estimated in *Section 3*) to the future supply to be extracted from already producing fields, adjusted for depletion and reserve growth. The result is a detailed picture of the big leap forward of the world’s total oil production capacity by 2020. A detailed analysis is devoted to the 23 most important oil producing countries of the world (the ones with a current capacity of future production higher than 1 million barrels per day).

Part II of the paper analyzes the most surprising factor of the world’s oil production upsurge—the U.S. shale and tight oil revolution—and its long-term consequences for the U.S. and the world. This part is articulated in five Sections starting with **Section 5**, which deals with the parallelism between the shale gas and shale oil phenomena in the U.S. It then defines shale and tight oils, and explains the differences between shale oil and oil shale. This Section also offers an historical account and a description of the primary features of horizontal drilling and hydraulic fracturing, the combination of which has been key to the shale/tight oil revolution.

Section 6 analyzes the case of the Bakken shale (a tight oil formation) in North Dakota, the catalyst of the U.S. shale revolution. The Section examines the different geological evaluations of the Bakken Shale, starting with the unparalleled study conducted by geochemist Leigh Price (1999), who has estimated the original oil present in the Bakken Shale formation to equal that of a major Persian Gulf oil producer. The Section also analyzes all available data from the Bakken and Three Forks (another tight oil formation that lies just beneath Bakken) formations, gathered from different sources and companies. Finally, this Section offers an evaluation of the Bakken/Three Forks production potential up to 2020.

Section 7 deals with the analysis and evaluation of other U.S. shale/tight oil formations (Eagle Ford shale, Permian Basin shale, Utica Shale, Niobrara/Codell shale) where a significant level of exploration and development activity is already underway, making it possible to gather data and predict future supply. This Section also includes a broad forecast of U.S. shale/tight oil production potential up to 2020, (the results of which are included in the world's total production capacity by 2020 analysis in Part I).

Section 8 analyzes the main technical problems that could significantly limit the deployment of the U.S. shale/tight oil from reaching its full potential. In particular, it examines the oil transportation and infrastructure gaps existing in the United States, the mismatch between the quality of most shale oils and the structure of the U.S. refining system, the supply of tools and skilled labor force required by intensive shale oil activity, and the problem of natural gas production associated with shale oil production.

Section 9 examines the single most important problem affecting the future of shale/tight oils: the environmental threat that their extraction seems to pose to water, land, and air.

Part III hinges on one single section (**Section 10**), exploring the macro factors that could significantly affect the estimations contained in this paper. This Section also examines the possibility of a collapse of oil prices in this decade due to a combination of a faster than expected surge in oil production and insufficient demand, and examining the different consequences such a collapse could have depending on its timing. Finally, this Section reflects upon the crucial concepts we can glean from this analysis beyond the numerical reports and predictions of future oil production.

I. A GLOBAL VIEW

1. NOT RUNNING OUT OF OIL: HOW HYDROCARBON RESOURCES EVOLVE

In 2011, the world consumed about 32 billion barrels of oil (crude oil and natural gas liquids), while oil proven reserves were about 1.3 trillion barrels. This means that those reserves should last more than 40 years. However, proven reserves are only a tiny slice of the overall supply of oil our planet hides.

On a global scale, the U.S. Geological Survey (USGS) estimates the remaining conventional oil resources in the earth at about seven trillion to eight trillion barrels, out of eight-to-nine trillion barrels of Original Oil in Place (OOP). Part of this (about one trillion barrels) has already been consumed by humankind. With today's technology and prices, only part of the OOP can be recovered economically and thus be classified as a proven reserve.²

The notion of recoverability is crucial to the oil industry. Given its complex nature, a hydrocarbon reservoir will always retain part of the oil and gas it holds, even after very long and intensive exploitation. Fields that no longer produce oil and are considered exhausted still contain ample volumes of hydrocarbons that cannot simply be economically recovered with existing technologies.

Today, the worldwide average recovery rate for oil is less than 35 percent of the estimated OOP, which means that less than 35 barrels out of 100 may be harvested. As often occurs with statistics, these figures hide huge disparities.

In most major producing countries, particularly those where international oil companies (IOC's) are not permitted to produce oil, the oil recovery rate is well below 25 percent, because of old technologies, reservoir mismanagement, limited investment, and many other factors. The situation has improved in the last decade, but not significantly.

For example, the current leading oil producers report about a 20 percent recovery rate.³ This group includes the Russian Federation, Iran, Venezuela, Kuwait, and others. Some of these countries have even lower recovery rates, in spite of their long and important history as producers.

Consider Iraq. Despite its long history as a producer, the country is largely untapped as far as oil development is concerned, according to the assessment made by the IOC's awarded re-development contracts between 2009 and 2011 (see Section 3). Since production began at the dawn of the twentieth century, only 2,300 wells (both for exploration and production) have been drilled there, compared with about one million in Texas.⁷ A large part of the country, the western desert area, is still mainly unexplored. Iraq has never implemented advanced technologies, like 3-

D seismic exploration techniques, or deep and horizontal drilling and hydraulic fracturing, to find or tap new wells. Of more than eighty oil fields discovered in the country, only about twenty-one have been partially developed.⁸ Given this state of underdevelopment, it is realistic to assume that Iraq has far larger oil reserves than documented so far, probably about 200 billion barrels more. These numbers make Iraq, together with a few others, the fulcrum of any future equilibrium in the global oil market.⁹ To date, the Iraqi recovery rate has been much less than 20 percent, and probably lower than 15 percent of its OOP.

Even the most oil-rich country in the world, Saudi Arabia, still has much potential to exploit. Despite a flurry of recent doubts about the actual size of its reserves (a renewed attempt to discredit the country's role as the world's Central Bank for oil), the Kingdom will probably continue to defy skeptics for decades to come. Currently, its 260 billion barrels of proven reserves, a fifth of the world's total, represent nearly one-third of the original oil in place estimated by the Saudi state oil giant, Saudi Aramco;¹⁰ yet the company has pointed out that its measurement does not take into account potential future advantages of enhanced recovery techniques.

On the opposite side of the spectrum are countries like the United States, Canada, Norway, and the United Kingdom, which record recovery rates above 45 percent, thanks to the open competition among international oil companies.

The United States is a mature oil country, whose oil production declined from 1971 to 2009. Yet, it still holds huge volumes of unexploited oil. Although the country has documented oil reserves of only 29 billion barrels, in 2007, the National Petroleum Council (NPC) estimated that 1,124 billion barrels were still underground, of which 374 billion barrels could be recovered with then-current technology.⁴

Thus, price and technology are key elements in determining the evolution of oil reserves. The evolution starts with the other characteristics of the phenomenon known as "reserve growth."

The USGS defines reserve growth "*as the estimated increases in quantities of crude oil, natural gas, and natural gas liquids that have the potential to be added to remaining reserves in discovered accumulations through extension, revision, improved recovery efficiency, and additions of new pools or reservoirs.*"⁵

It is important to bear in mind that "reserve growth" concerns existing fields only, not newly discovered ones, and because of this, hydrocarbon reserves may increase without the discovery of new fields. In fact, history has proved that "additions to proven recoverable volumes" of hydrocarbon have been "usually greater than subtractions," without any new oil discovery.⁶

Reserve growth is a crucial element in the evolution of oil supply, and is often ignored or underestimated. Most analyses on oil reserves and supplies focus primarily on depletion rates of already producing oil basins, subtracting from reserves, and assuming a reduction of future production, without adequately factoring in their reserve growth. This underestimates the production of several oilfields, particularly the larger ones.

Two prominent geologists from the U.S. Geological Survey conducted a brilliant examination of “reserve growth” on a global scale. According to their extensive analysis, the estimated proven volume of oil in 186 well-known giant fields in the world (holding reserves higher than 0.5 billion barrels of oil, discovered prior to 1981) increased from 617 billion barrels to 777 billion barrels between 1981 and 1996.⁷

Because of “reserve growth,” a country or a company may increase its oil reserves without tapping new areas if it can recover more oil from its known fields. One of the best examples of the ability to squeeze more oil from the ground comes from the Kern River Field in California.

When the Kern River Oil Field was discovered in 1899, analysts thought that only 10 percent of its unusually viscous crude could be recovered. In 1942, after more than four decades of modest production, it was estimated that the field still held 54 million barrels of recoverable oil, a fraction of the 278 million barrels already recovered. As observed by Morris Adelman, “In the next 44 years, it produced not 54 [million barrels] but 736 million barrels, and it had another 970 million barrels remaining.”⁸ But even this estimate proved incorrect.

In November 2007, U.S. oil giant Chevron, by then the field’s operator, announced cumulative production had reached two billion barrels. Today Kern River still yields nearly 80,000 barrels per day, and the state of California estimates its remaining reserves to be about 627 million barrels.⁹

Chevron began to increase production markedly in the 1960s by injecting steam into the ground, a novel technology at the time. Later, new exploration and drilling tools, along with steady steam injection, turned the field into a kind of oil cornucopia.

Kern River is not an isolated case. The oil literature is filled with cases of oilfields that gained a second or third life after years of production, thanks to new technologies that made it possible to estimate the size of an oilfield resource better, to discover new satellites of the main oilfield, to extract more oil, and to manage the drilling and production operations better.

The exact boundaries of a large oilfield can not be known with complete confidence until years or decades of successive geophysical analysis and adequate drilling have gone by. A reservoir may extend through tens or even hundreds of square miles and, have a vertical depth and a horizontal extension that are initially unknown. Consequently, during the first years of exploration and

production, estimates of hydrocarbon resources contained in an oilfield tend to be incomplete and conservative.

All of these elements point to a fundamental concept: knowledge of already discovered oil resources is not static, but increases over time through the expansion of scientific understanding of the fields. This explains why resources increase over time in tandem with increased knowledge, though a dynamic, ongoing process. In other words, estimates of reserves are not carved in stone.

This is even truer for what we do not know, that is, the unexplored areas of the world. Only one third of the sedimentary basins of our planet (the geologic formations that may contain oil) have been thoroughly explored with modern technologies including advanced seismic prospecting and deep exploration drilling. For example, until a few years ago, it was impossible to look through pre-salt formations with traditional seismic technology, or tap hydrocarbons below more than 5,000 or 6,000 feet of water. Moreover, large parts of Africa and Asia and many deep and ultra-deep offshore basins are still unexplored.

Exploration wells (also known as wildcats in oil jargon) represent a good proxy of the real knowledge of our planet's hidden secrets, because they follow careful geological and seismic evaluations of the subsoil. Only about 2,000 new wildcat fields have been drilled in the entire Persian Gulf region since the inception of its oil activity, compared to more than one million in the United States.¹⁰ Even today, more than 60 percent of drilling activity is concentrated in North America (United States and Canada), as reflected by the rig count numbers made available each month by Baker Hughes.

All of this said, however, our planet most likely does not hide many more gigantic basins of conventional oil, for which discovery peaked in the 1960s. Some of these formations might still be hidden in the ultra-deep offshore or in other environmentally hostile areas, such as the Arctic Sea, but it is improbable that conventional oil basins such as those discovered in the early 20th Century in the Persian Gulf, in Texas, or a few other areas of the world are yet to be found. But a new paradigm may render these questions irrelevant.

While aggregate conventional oil production capacity continues to grow, a process of “de-conventionalization” of oil reserves will likely result in an expanding wave of “unconventional oil” production.

According to the U.S. Energy Information Administration (EIA) definition, conventional crude oil and natural gas production refers to oil and gas “produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the oil and natural gas to readily flow to the wellbore.” By converse unconventional hydrocarbon production doesn't meet these criteria, either because geological formations present a very low level of porosity and

permeability, or because the fluids have a density approaching or even exceeding that of water, so that they cannot be produced, transported, and refined by conventional methods. This umbrella definition, then, encompass ultra-heavy oils, shale and tight oils, tar sands, and oil shale.

The USGS (2003)¹¹ and the World Energy Council (WEC, 2007)¹² estimated that there could be more than 9 trillion barrels of unconventional oil resources beneath the surface of our planet, with only 300 billion barrels of them potentially recoverable at the time of that estimation. However, as we can see from the shale/tight natural gas and oil boom in the U.S., those kinds of evaluations were both based on a conservative probabilistic approach that was already outdated, as they could not factor in the rapidly evolving use of new technologies to explore and develop hydrocarbon basins.

In fact, the current decade could herald the advent of “unconventional oil” as “the oil of the future,” changing the geopolitical landscape that has marked the oil market for most of the 20th Century. Most of the known unconventional oil resources, and about 70 percent of those considered “recoverable” today, are concentrated in Canada, the United States, and Venezuela.

The fact that a significant portion of tomorrow’s oil supply might come from unconventional resources has led many observers to talk about the end of “cheap oil.”

The expression “cheap oil” has not exact boundaries. Generally, it is used in reference to the cheap oil prices prevailing over the second half of the 20th Century, when oil price in real terms (2000 U.S. dollars) ranged between \$20-30 per barrel, with some noteworthy exception (such as during the period of the oil shocks in the 1970s and early 1980s, when the price of oil largely exceed \$ 100 per barrel in real terms).

If we do accept this definition of cheap oil, we may come to the conclusion that the bulk of it is almost depleted, also because it was the first to be discovered and exploited. Many of the largest and most productive oil basins in the world are approaching what I call technological maturity; the point at which traditional technologies are no longer effective. These basins include reservoirs in Persian Gulf countries, Mexico, Venezuela, and Russia, which started yielding oil in the 1930s, 1940s, and 1950s. For these fields to keep producing in the future, new technologies will be necessary; that requires additional costs.

This influx of new technology is already being developed in several countries, continuing the productive life of many of the oldest and most prolific oilfields in the world, starting with the largest conventional oilfield ever discovered, al-Ghawar in Saudi Arabia. It has been delivering an impressive 5 mbd for many years, and it will continue to do so for the rest of this decade.

Yet a considerable measure of today’s “easy and cheap” oil was not so easy and cheap when it was discovered.

Consider North Sea oil, for example. When it was developed in the 1970s, it seemed that offshore technology had reached its most daunting frontier, tapping fields that lay below 100 to 200 meters of water and 1,000 meters under the seabed. The cost of operating in those conditions seemed to be prohibitive, and only the two oil shocks of the 1970s and the consequent spikes in oil price made North Sea oil profitable. Yet after ten years of intense exploration, development, and developing infrastructure, the cost of discovering and developing North Sea oil has decreased by 50 percent. Today, the oil industry can strike oil below 3,000 meters of water and 6,000 meters of rock and salt; the limits of the North Sea in the 1970s are business as usual today.

There is a learning curve for new technology, but the difficult oil of today will be the easy oil of tomorrow.

2. METHODOLOGICAL PROBLEMS IN EVALUATING FUTURE SUPPLY

First, it is important to recall that in most statistical sources, the expressions “oil production”, “oil supply”, and “oil production capacity” usually include both crude oil and natural gas liquids (NGLs, i.e. ethane, propane, butane, pentane, etc.). In this paper, I use “oil production/capacity” and “liquid production/capacity” interchangeably, the latter being clearer for the general reader.

At the beginning of 2012, total liquid production capacity was about 93 million barrels per day (mbd). About 77 mbd of that was crude oil supply capacity.

Second, any assessment of the future of oil production should take into account the asynchronicity between the evolution of demand and supply, which emerges from several elements. First, investment cycles for exploration and development of oil and natural gas deposits are very long, averaging between eight and twelve years. Consequently, development of new production is out of sync with both the demand for oil and its price.

The industry tends to increase investment gradually as the price of crude oil increases, but once the new investments are started, they are very difficult to stop, even when consumption and crude oil prices suddenly collapse. In other words, the industry behaves like an elephant running: it starts very slowly, but once it gets going, no one can stop it.

In fact, as an oil company gradually spends its budget, the investment assumes a life of its own, and it becomes unprofitable to block the spending, especially when hundreds of millions of dollars have already been spent. The need to obtain an economic return on capital already invested takes priority over almost any other consideration, unless there are dramatic changes in the market situation.

To complicate matters, contractual commitments are made by the oil companies with the countries owning the deposits, which often make it difficult to block or reduce the spending. Indeed, these

commitments demand heavy economic penalties or even revocation of the concessions granted by the host government if, by pre-established dates, the agreed number of wells and the needed infrastructure are not realized, and initial production is not achieved.

The only companies that can effectively block or significantly rein in their own investments in the event of a negative market situation are national oil companies belonging to the producing countries themselves, whose investment policies must be approved by those same governments that own the companies. Another exception occurs in the United States and Canada, where the freedom to make business decisions (including the decision to block investments already approved) is unique in the world, thanks to the presence. This is particularly true in the case of U.S. shale/tight oil and Canadian tar sands development, where the production unit is not a field, but a single well or a single, limited portion of a tar-sand basin. In this case, companies may effectively decide to rein in investments as soon as a sudden dip of oil price occurs.

Third, every public company must replace reserves "consumed" each year, a problem that has reached critical dimensions in the last two decades, given the increasing difficulty of accessing the reserves of the big oil-producing countries, especially in the Persian Gulf. Thus, the objectives of replacing reserves, and maintaining or increasing future production of oil and gas, often override purely economic considerations.

Finally, even when oil prices and demand collapse, the oil industry tends to believe that the collapse is a short-term phenomenon, so that it tends to slowly cut new initiatives, but finds it very difficult to impede those that have already been initiated, unless the downturn persists for a sufficiently long period of time (more than one year at least). However, even then, it is more likely that scheduled investments will be deferred, rather than block initiatives already started. Also in this case, the U.S. shale/tight oil and the Canadian tar sands represent an exception.

Because of the asynchronous relationship between production development and the evolution of demand and oil prices, it is misleading (and often wrong) to assess the development of oil production as a simple function of demand that, in its turn, is calculated as a function of economic growth according to the general economic equilibrium paradigm used by most econometric models. It is even more misleading to make long-term predictions—twenty years or more—having no real tool for evaluating the evolution of technology, of political decisions, of prices, and so on.

For all these reasons, a correct evaluation of the future oil supply growth should depend on a relatively short period of time (in the case of this paper, to 2020), and start with a bottom-up analysis, i.e., a field-by-field analysis of all projects currently active in the world to develop new oil production or to maintain existing production. These projects should include all those initiatives that are already in a building phase or in a planning stage after the formal signature of committing contracts.

Even though it covers less than a decade, this kind of analysis entails a margin of randomness, because project development may be delayed for lack of equipment, skilled labor force, infrastructure, political and geopolitical issues, and contractual clashes between the operator and the host country. Moreover, from a technical point of view, initial estimates about production increase and maximum production may prove to be too optimistic (although the opposite is often true). Historically, most initial estimates about the size of a field and its oil recoverability turn out to be very conservative, mainly because of the lack of sufficient knowledge of the reservoir, and the limited range of technologies considered initially for oil recovery.

To account for the problems affecting bottom-up analysis, the unrestricted, additional future production (i.e. the potential result from simply completing all planned projects) should be reduced by a risk-factor that would vary from country to country, or from field to field, leading to an adjusted additional production figure.

Unfortunately, the oil sector has no precise methodology by which to adjust reserve and production forecasts for risk factors.

Even when dealing with familiar problems like the definition of proven, probable, and possible reserves, the methodology defined by the Society of Petroleum Engineers (SPE) is very rough: 90 percent probability for proven reserves, 50 percent for probable, and 10 percent for possible.

The same is true for the assessment of a new exploration and development project. Before investing in a single oilfield, each company prepares a business plan based on the mean probability of several variables, such as expected oil prices, proven and possible reserves, the possible production profile, and many more. The assessment of these variables, in turn, is based on the subjective evaluation of the people in the field and company planners. Each of these business plans also contains two less detailed scenarios: 1) an “acid test,” or “stress test,” showing what could happen if, for example, the oil price were to dip below a certain level, or the expected production should be lower than the target; 2) an “upside test”, showing the effect on the internal rate of return of oil prices or production levels that are higher than planned. However, given the number of variables involved in these scenarios, planners present them only as broad-brush assessments.

For this paper, I decided to use only the mean probability scenario and to clearly disclose the percentages I used to adjust the country production profiles for risk factors, trying to be as conservative as possible. Although arbitrary, this method does allow readers to make their own evaluations. For the same reason, I used tables that precisely sum up the change in production of all major countries, so that readers can see clearly how the aggregate numbers of world production are reached. Charts attempting to do this are usually more confusing and less revealing in terms of displaying the precise bottom-up analysis that leads to the aggregate figures. I further explain some the basic elements of my methodology in the Appendix.

Another key tool in evaluating the future supply of oil is the assessment of the future production profile of already producing oilfields. This analysis requires a complex consideration: their “depletion rate,” that is, their natural decline after years of production, partially offset by any possible reserve growth.

Without offering a detailed explanation of the behavior of an oilfield, suffice it to note that each oilfield goes through three production stages: production build-up, production plateau (maximum level of production), and the decline period.

Each of these stages may present huge variations for different reasons: the size of a field (smaller fields tend to decline faster); reservoir physics and knowledge (the latter increasing over time); technology used for field development; investments; political decisions concerning the development (including tax regime, royalties, and contractual schemes).

Thus, it is impossible to predict the precise future production profile of an oilfield. As we have seen in Section 1, the history of oil is filled with examples of big oilfields that entered a second producing life thanks to new technologies concerning the knowledge of the reservoir, its operation, and oil extraction—all factors contributing to their reserve growth. Therefore, one can only make reasonable hypotheses of the long term producing profile of an oilfield.

To achieve such a task, one would need to start with a detailed, field-by-field database of all the oilfields in the world. Even with that, however, the estimate of the world depletion rate adjusted for its reserve growth would still be a gross approximation of the future figure, because of the different factors affecting the profiles of each individual field.

Neither the International Energy Agency (IEA), nor other public institutions possess such a database. To my knowledge, the only companies that have an extensive database of world’s oilfields are IHS-CERA (U.S.) and Wood Mackenzie (UK). Yet each agency, think-tank, or institution that deals with the future of oil production draws up its own production profiles and depletion rates based on (in the best case) probabilistic models and historical data, without either a comprehensive, field-by-field database, or a tool to track the evolution of technology, reserve growth, etc. Consequently, their estimates are often unrealistic, or simply biased by the convictions of their authors.

For example, in its World Energy Outlook 2008, the International Energy Agency alleged that it performed an “exhaustive field-by-field analysis” collaborating with IHS-CERA, which owned the field-by-field database. Yet the numbers of IEA and those of IHS-CERA differed significantly. The IEA projected the world oil average decline rate up to 2030 would increase to over 10 percent by 2010, while IHS-CERA predicted a 4.5 percent depletion rate.

Throughout recent history, there is empirical evidence of depletion overestimation. From 2000 on, for example, crude oil depletion rates gauged by most forecasters have ranged between 6 and 10 percent: yet even the lower end of this range would involve the almost complete loss of the world's "old" production in 10 years (2000 crude production capacity = about 70 mbd). By converse, crude oil production capacity in 2010 was more than 80 mbd. To make up for that figure, a new production of 80 mbd or so would have come on-stream over that decade. This is clearly untrue: in 2010, 70 percent of crude oil production came from oilfields that have been producing oil for decades.

As shown in Section 4, my analysis indicates that only four of the current big oil suppliers (big oil supplier = more than 1 mbd of production capacity) will face a net reduction of their production capacity by 2020: they are Norway, the United Kingdom, Mexico, and Iran. Apart from these countries, I did not find evidence of a global depletion rate of crude production higher than 2-3 percent when correctly adjusted for reserve growth.

3. A MOUNTING WAVE OF UNDERESTIMATED SUPPLY

From 2003 on, oil exploration & production (E&P) worldwide entered a new, impressive investment cycle, encouraged by ever increasing crude oil prices, private companies' desperate need to replace their reserves, the re-emergence of Iraq as a major oil player, and the inaccurate but still widespread perception that oil is bound to become a rare commodity.

That cycle reached the status of a boom between in 2010 and 2011, when the oil industry invested more than \$1 trillion worldwide to explore and develop new resources. According to Barclays' Upstream Spending Review, 2012 might represent a new all-time record since the 1970s in terms of E&P investments, with a conservative estimate of slightly less than \$ 600 billion.¹³

What is the relationship between these new investments and the potential production to be developed by the year 2020?

To answer this question, I developed a detailed database of investments currently underway, or committed under signed contracts, field-by-field in more than 40 countries worldwide.

This method allowed me to approach the issue of future production from the bottom up. To focus my analysis most effectively, I restricted my research to 23 countries representing more than 80 percent of current production capacity and more than 95 percent of future production growth.

The initial work was made possible by a proprietary database I have generated throughout my career, compounded through a few sources having extensive field-by-field databases, including *Oil & Gas Journal* (OGJ) (the oldest technical publication in the oil sector), IHS-Cera, and Wood

Mackenzie. I could not access the IHS-CERA and Wood Mackenzie sources after August 2011, but that was not crucial because I reviewed and crosschecked the individual production plan for each country using other sources, such as the excellent publications of the Energy Intelligence Group,¹⁴ official data from producing countries, and new oil company information about changes in various projects. Table 1 and Table 3 (in Section 4) show the results of my analysis.

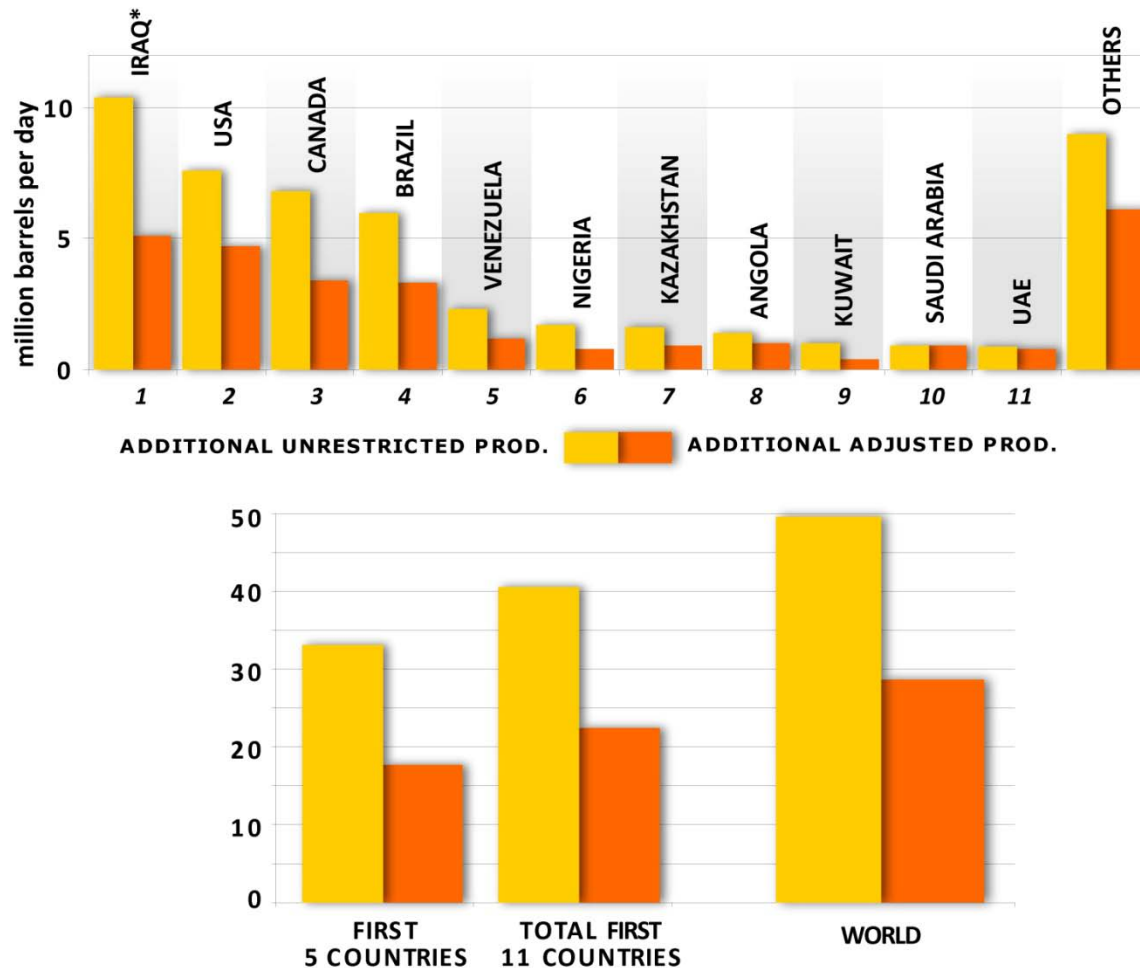
Figure 3 is the starting point. I divided the data into two sets: the first set represents the “additional unrestricted supply” of the fastest-growing countries to 2020 in terms of new oil production based on the completion of projects planned or already in process. These projects include both newly developed fields (from which first-oil production is yet to come or is impending) and major redevelopments of already producing fields (as in Iraq and the UAE).

The second data set represents the additional supply considering risk (“adjusted additional supply”), the result of reducing the “unrestricted” potential to account for all the risks affecting the development of the projects.

Note that Figure 3 *does not consider already producing oilfields (unless under major redevelopment) in the listed countries, the future output of which, adjusted for depletion and reserve growth, must be subtracted/added to the data concerning the additional adjusted production.* Table 2 in Section 4 sums up this exercise, incorporating other countries not included in Figure 3.

My field-by-field analysis suggests that worldwide, an additional unrestricted supply of slightly less than 50 mbd is under development or will be developed by 2020. Eleven countries show a potential outflow of new production of about 40.5 mbd, or about 80 percent of the total. After adjusting the world’s additional unrestricted production for taking into account risk-factors, the additional adjusted supply comes to 28.6 mbd, or 22.5 mbd for the first eleven countries – as shown in Figure 3 (more extensive data are shown in Table 3, Section 4).

Figure 3: Worldwide potential additional liquids supply out to 2020 (crude oil and NGLs, excluding biofuels)
First 11 major countries in terms of incremental new supply (million barrels per day / mbd), not considering depletion and reserve growth.



** Including the Kurdish region*

My field-by-field analysis suggests that worldwide, an additional unrestricted supply of slightly less than 50 mbd is under development or will be developed by 2020. Eleven countries show a potential outflow of new production of about 40.5 mbd, or about 80 percent of the total. After adjusting the world's additional unrestricted production for taking into account risk-factors, the additional adjusted supply comes to 28.6 mbd , or 22.5 mbd for the first eleven countries – as shown in Figure 3 (more extensive data are shown in Table 3, Section 4).

These numbers carry at least two important messages:

- They represent the largest potential addition to the world's oil supply capacity since the 1980s.
- They point to a tectonic shift in the oil geography and geopolitics, by making the Western Hemisphere the fastest growing oil-producing region in the world, with the United States and Canada combined outpacing any other country.

Countries excluded from Figure 3 might also bring significant new production of crude oil and NGLs. In particular, Algeria, Libya, Russia, Qatar, China, and India could deliver between 500,000 bd and 1 mbd of unrestricted new supply, (see Table 3, Section 4). Libya could even exceed 1 mbd on additional production, but the bulk of this is the consequence of recovering supply capacity that was lost during the civil war (hence, why Libya was excluded from Table 1). The remaining new production will develop from a mosaic of countries, while other minor producers (less than 200,000 bd of current production capacity) will face an overall decline in their production.

Several countries where oil production is growing belong to OPEC, which are subject to comply with the organization's allocation of pro-rata production quota. From time to time, this could affect their actual production (if they effectively comply with their production quotas), but not the ongoing growth of the production capacity. As I will explain in the last Section of this paper, only a significant collapse of oil prices could stop part of the ongoing investments aimed at developing that capacity.

Below are my main assumptions regarding the countries in Figure 3.

Iraq. Iraq is a major global source of potential oil production growth by 2020. In 2009, the Iraqi government awarded the redevelopment of 11 of the country's oilfields to several international oil companies. Redevelopment contracts for other big fields, including super-giants Kirkuk, East Baghdad, and Nasiriyah, have not been awarded, while the first auction for some of the country's unexplored fields should be held in 2012. The redevelopment contracts awarded so far target a total production of more than 11.6 mbd, an increase of about 9.6 mbd over the current level of the considered fields (see Table 1) that do not encompass the whole of Iraqi oilfields.

According to several companies, most revamping and redeveloping test data on Iraqi fields showed a rapid increase in production and a steady flow of oil. In some cases, I found evidence that future production could significantly exceed the contractual targets agreed upon with the Iraqi government. This could be because the poor technology and bad reservoir management used in the past left several of the country's fields scarcely exploited. Still, Iraq's enormous potential for oil is threatened by several problems that could significantly reduce its future supply.

Table 1: Peak planned production of already awarded Iraqi oil contracts (*excluding the Kurdish region*)

Field	Foreign Companies (Share)	Production Target (initial production)
Rumaila	BP (38%) CNPC (37%)	2,850,000 (1,100,000)
West Qurna 1	Exxon (60%) Shell (15%)	2,350,000 (270,000)
Zubair	Eni (32.8) Occidental (23.5%) Kogas (18.75)	1,200,000 (200,000)
Missan fields**	CNOOC (63.75%) TPAO (11.25%)	450,000 (100,000)
Majnoon	Shell (45%) Petronas (18.75%)	1,800,000 (50,000)
West Qurna 2	Lukoil (56.25%) Statoil (18.75)	1,800,000 (120,000)
Halfaya	CNPC (37.50%) Petronas (18.75%) Total (18.75%)	535,000 (70,000)
Gharaf	Petronas (45%) Japex (30%)	230,000 (35,000)
Badra	Gazprom (30%) Kogas (22.5%) Petronas (15.5%) TPAO (7.5%)	170,000 (15,000)
Qaiyarah	Sonangol (75%)	120,000 (20,000)
Najmah	Sonangol (75%)	110,000 (20,000)
Total Production Targets * (Current capacity)*		11,615,000 (2,000,000)
Iraq Total Current Capacity***		2,800,000

**Excluding the Kurdish Region*

***Includes the Fakka, Buzurgan and Abu Ghirab fields*

****End of 2011. Includes other fields that still await re-development, such as supergiant Kirkuk, East Baghdad, and Nasiriyah.*

Thus far, the Iraqi government has mismanaged the oil sector on several fronts, which has hindered the advancement of oil production. The list of misguided actions is quite long. The government has approved companies' plans too slowly, particularly for critical services and equipment, leaving them incapable of moving forward. It has obstructed the reimbursement of accrued costs, further heightening the IOC's reluctance to operate in a country with such a risk of poor economic return, even in the best-case scenario. The Iraqi oil service-contract model requires paying the companies operating the country's oilfields in dollars, rather than with a share

of the crude they develop. The model also prevents companies from including Iraqi oil reserves on their books, except for a miniscule share. The government fees paid to the oil companies are relatively modest, while the risk of downsizing is significant. Thus, Iraqi contracts have low profitability compared to other kinds of oil contracts, and this fuels the perpetual confrontation between the central government and the companies involved in the country's oil sector.

Moreover, for many years the government has done nothing significant to address the enduring problems of oil export-bottlenecks or the lack of adequate facilities and infrastructure essential to support the growth of oil production. To exacerbate the uncertainty, the security situation continues to fluctuate.

Only at the beginning of 2012 some important things happened that could change the future prospects of the Iraqi oil sector. Exxon and Baghdad struck a deal in which Exxon could be paid in oil. Separately, Baghdad brought on line two single point mooring (SPM) export terminals systems with the export capacity of 850,000 barrels each, which could substantially enhance the country's production, and has two more that could be developed by the end of 2012.

This progress may improve Iraqi future production, but considering all risk factors, I cut the Iraqi additional unrestricted production of 9.6 mbd in half, to 4.8 mbd by 2020, including depletion of already producing fields. This is more than offset by the re-development plans of international oil companies and *still excludes the supergiant fields awaiting re-development (Kirkuk, East Baghdad, and Nasiriya). It also excludes the Kurdish region, which requires a short digression.*

As of February 2012, the semiautonomous Kurdish Regional Government (KRG) had signed about 40 contracts with more than 40 international oil companies to redevelop and expand the region's oil and gas fields, which at the end of 2011 were producing about 175,000 oil barrels daily.

The most important of these contracts was signed with ExxonMobil in December 2011 and led to a clash between the KRG and the Iraqi central government, which has always affirmed that would not recognize oil contracts separately signed by the KRG and would blacklist all companies that sign those deals, excluding them from any activity in the rest of the country. So far, it is still unclear how this situation will be resolved (Exxon is already developing the Iraqi supergiant West Qurna 1).

The Kurdish region could produce up to 1 mbd of oil by 2020, or 825,000 bd more liquids than at the end of 2011. Yet, like the rest of Iraq, it is constrained by the lack of infrastructure and export capacity. Moreover, without some kind of agreement with the central Iraqi government, many international oil companies have always been cautious about making major investments in the region. All this led me to cut 500,000 bd from the overall Kurdish production capacity by 2020, which would involve 325,000 bd of additional adjusted production by then.

In total, Iraq could enjoy additional, unrestricted new production of 10.425 mbd by 2020 (9.6 mbd from Iraq and 825,000 bd from the Kurdish region), or 5.125 mbd recognizing the risks.

Once again it is worth emphasizing that this assessment does not include either the redevelopment of some important Iraqi supergiant oilfields such as Kirkuk, East Baghdad, and Nasiriya, or potential new oil discoveries from exploration contracts that Iraq awarded in 2012.

United States. The United States represents by far the biggest surprise in the upcoming oil revolution because of the potential upsurge of shale-oil/tight oil production by 2020. Because of its relevance, I devoted the second part of this paper to it (see Sections 5-9). I estimate that additional unrestricted production from shale/tight oil might reach 6.6 mbd by 2020, or an additional adjusted production of 4.1 mbd after considering risk factors (by comparison, U.S. shale/tight oil production was about 800,000 bd in December 2011). To these figures, I added an unrestricted additional production of 1 mbd from sources other than shale oil that I reduced by 40 percent considering risks, thus obtaining a 0.6 mbd in terms of additional adjusted production by 2020. In particular, I am more confident than others on the prospects of a faster-than-expected recovery of offshore drilling in the Gulf of Mexico after the *Deepwater Horizon* disaster in 2010. This confidence is based on the renewed enthusiasm Americans have found for the possibility of “energy independence” thanks to the country’s huge hydrocarbon resource base, and for the economic impact that growing domestic oil production might have on the American economy as a whole.

Adding shale/tight oil production to other U.S. production brings the total “unrestricted” new supply of the U.S. to 7.6 mbd by 2020, and an additional adjusted production of 4.7 mbd.

Canada. The country ranks third among the most promising countries in terms of production growth. Most of this will come from further development of tar sands, which jumped from 600,000 bd in 2000 to 1.5 mbd in 2011. I reviewed a list of more than 140 projects underway (the largest among the countries considered), some of them quite small, mostly representing possible phases of development of the same field. Considering them all, the additional unrestricted oil production of Canada might reach 6.8 mbd through 2020. Yet the case of Canada also requires caution.

Environmental concerns about massive tar sands exploitation may obstruct or delay future development, while the lack of adequate export capacity to absorb the growing production may force companies to postpone several projects. In particular, the United States absorbs some 97 percent of Canada’s oil exports, which will represent a critical outlet for future Canadian production. In early 2012, however, the Obama administration decided to postpone the decision about construction of the Keystone XL crude oil pipeline, an arm of which is essential to connect Canada to the Texas Gulf coast. There is strong environmental opposition to building new

pipelines on U.S. territory to transport the corrosive and pollutant heavy oils from Canadian tar sands. Among other concerns, the tar sands' carbon footprint is 17 to 23 per cent larger than that of light oil. The same opposition that stopped the Keystone XL makes future prospects of Canadian oil exports to the U.S. less certain. In fact, although critical for the future advancement of Canadian oil production, the Keystone project alone cannot provide adequate growth of U.S. import capacity.

As detailed in Section 8, most of the Western Canadian oil production relies on the same transportation corridor that serves North Dakota's Bakken Shale and other U.S. shale/tight oil plays, where production is rising dramatically. That transportation corridor is already inadequate to sustain today's takeaway needs from those areas.

Canada is now considering diversifying its export routes; China and other Asian countries are ready to jump at this opportunity. Until the problem of export capacity is solved, it will be difficult for the country to fully deploy its oil potential.

Some of the Canadian projects examined for this research, then, present the highest marginal cost among the world's oil projects, showing an internal rate of return (IRR) higher than the weighted average cost of capital (WACC) only at a price of \$90 per barrel or higher, an aspect that makes them highly price-sensitive (other tar sands projects have much better economics, depending on their location and the presence of already developed infrastructure).

Finally, availability of skilled labor to work on the impressive number of Canadian oil projects adds another level of uncertainty to their timely realization.

These factors suggest reducing "unrestricted" potential future new production of Canada by 50 percent, which puts its reasonable growth at 3.4 mbd, before considering depletion of its conventional production. That is significant (See Section 4).

Brazil. The important discoveries of the last decade in the Santos Basin Lula (formerly Tupi) and the Campos Basin, including ultra-deep offshore and pre-salt formations, drive the unrestricted additional production growth to 6 mbd by 2020.

However, about 2.5 mbd of this new production is critically linked to the development of oil-rich pre-salt formations, which are costly to develop, making them highly price-sensitive. Worldwide, few operators are capable of addressing the environmental and technological challenge they pose. Moreover, growing resource nationalism has supported legislation that imposes Petrobras—the Brazil national oil champion—as the sole operator of every sub-salt field. While one of the best national companies (or semi-national, because Petrobras is partly floated) in the world, Petrobras is likely not capable of managing this task on multiple fields in a relatively short period of time.

Consequently, I reduced potential new production from these formations by 60 percent, setting the figure to 1 mbd by 2020. The remaining 3.5 mbd of unrestricted additional oil supply might face uncertainties, too. In particular, new regulations on lower associated gas-flaring and current laws requiring the use of local labor could compel companies to postpone oilfield development. For these reasons, I reduced the 3.5 mbd figure by 35 percent, yielding a total potential of 2.28 mbd. Adding the potential from pre-salt formations, Brazil's total new supply, considering risk, might be about 3.3 mbd.

Venezuela. OPEC has recently recognized that Venezuela has the largest proven oil reserves in the world, estimated at about 300 billion barrels. In principle, this endowment more than supports a relatively modest, unrestricted additional oil production of 2.3 mbd by 2020, based on field-by-field analysis of the development projects underway in the country. Even this figure, however, has several clouds hanging over it.

One-third of Venezuelan oil reserves is made up of extra-heavy oils, a good part of which could be profitably exploited (at 2011 costs) only with an oil price higher than \$70 per barrel. Another third or more of those reserves is formed by heavy oil, which requires a price of oil of \$60 or more to be profitable. To be marketed, they all need to be adequately processed.

In addition to the technical problems and costs affecting several Venezuelan oil projects, there is a Sword of Damocles hanging over the long-awaited increase in oil supply;¹⁵ the nationalistic policies of the Chavez government. That is also why Venezuela oil production capacity has been declining since its two peaks in 2005 and 2008, when it reached 3.5 mbd. It now stands at about 2.7 mbd.

In spite of the country's oil potential, Chavez's confrontational policies may endanger not only the fields already producing, but also new initiatives. Maintaining production in existing oilfields and developing new ones are both highly capital-intensive efforts, which neither Venezuela nor the national oil company PDVSA can support alone. The cancer affecting Chavez is now posing serious questions about what will happen in Venezuela should Chavez die. In my view, a more probable outcome could be a prolonged period of political and economic instability and even of violence, given both the probable implosion of the Chavist movement due to the lack of a strong leader, and the fragmentation and reciprocal hostility that characterized the opposition parties.

For these reasons, I cut the unrestricted potential of the country in half, to 1.2 mbd.

Nigeria. The oil infrastructure in the Niger Delta, Nigeria's most prolific oil province, is now less vulnerable to attacks by militant groups of the Movement for the Emancipation of the Niger Delta (MEND), now that most MEND leaders have applied for the government's amnesty process. However, sporadic attacks and kidnappings continue to remind us that the situation in the area is far from settled. Moreover, sabotage, oil thefts from pipelines, and damages to oil infrastructure

caused by repeated attempts to steal oil by local population and armed groups continue to cause significant production halts and oil production losses.

In any case, the major problem for the oil sector now is regulatory uncertainty. A new oil bill to increase royalties and taxes hangs over the future of the Nigerian oil industry, even though no final decision has been made after years of debate, delays, and amendments. Meanwhile, the government has been reluctant to sign new oil deals or renew expired ones, although some old licenses can be rolled over until the uncertainties are resolved. Exploration is stagnating, and there has been no international bid round for new blocks since 2007.

Yet the most important development projects, with a targeted production capacity of 100,000 bd or more, are due to reach their peak production before 2015. That is the case, for example, of Exxon's operated Satellite Projects phases 1-5 (370,000 bd), Bosi (135,000), and Uge (110,000 bd), Shell's Bonga complex (290,000 bd), Total's Egina (200,000 bd) and Usan (180,000 bd), among others.

Balancing the regulatory uncertainty, the residual risk of instability in the Niger Delta, and the ongoing activity, I reduced the future new production potential of the country by slightly more than 50 percent, setting additional adjusted production at 800,000 bd by 2020.

Angola. Angola's oil production is steadily increasing, and the country is awaiting the start-up of its first ultra-deep water oil project, the BP-led PSVM (Plutao, Saturna, Venus, Marte) in Block 31 (2,000 meters of water), with a peak production target of 150,000 bd of liquids. This is a very important step forward for the country, because the bulk of its new production should happen before 2015 from ultra-deep offshore basins, such as the other BP-operated fields in Blocks 31 (300,000 bd) and 18 (75,000 bd), the Total-operated fields in Block 17 (380,000 bd, 2,600 meters of water), the Exxon-operated Kizomba satellites in Block 15 (125,000 bd), and the Chevron-operated fields in Block 14 (about 140,000 bd).

Given the stability of the country, I reduced the unrestricted additional production of Angola by 25+ percent, mainly because of the challenging ultra-deep offshore environment, putting the potential new production at 1 mbd.

Kazakhstan. The country's potential is without doubt, but Kazakhstan has become a sort of never-ending story of missed deadlines and growing problems.

The bulk of the country's new production should come from Kazakhstan's three giant fields, Kashagan, Karachaganak, and Tengiz, with Kashagan playing the dominant role through its subsequent expansion phases (1,550 bd). New offshore discoveries might add to the country's potential output as well. However, after years of bold announcements and subsequent setbacks, several problems continue to obscure the country's oil future.

The most critical issue is the continuing confrontation between the Kazakh government and foreign oil companies over fiscal controversies, the government's intention to have its national oil and gas companies share in the major projects, and many other issues.

For example, in 2011, the government reintroduced and soon doubled an export duty on crude from which the major foreign operators claimed exemption. Hard negotiations are still underway for the Kazakhstan's proposed purchase of a 10 percent stake in the Karachaganak field (jointly operated by Eni and BG Group), which would be crucial to further development of the field. The production expansion of the Chevron-operated Tengiz field is hindered by administrative problems. Finally, the supergiant Kashagan field (the biggest conventional oilfield discovered in the last 35 years) still awaits early production after missing several deadlines and incurring skyrocketing costs, which in turn has stressed relations between the government and the consortium of foreign companies developing the field.

All these factors make Kazakhstan one of the trickiest countries for foreign companies to work in, and puts in serious doubt the government's ambitious plan to produce 2.64 mbd of crude oil (up from 1.6 mbd in 2011), and an additional 400,000-500,000 boe of NGLs, a total target of more than 3 mbd by 2020.

I reduced the additional unrestricted supply of 1.6 mbd by slightly more than 40 percent, yielding a potential new supply of about 900,000 mbd of crude oil and NGLs.

Kuwait. On paper, expansion plans approved by the government aim at raising the country's production capacity to 4 mbd from its current 3 mbd (including the 50 percent Kuwaiti stake in the Neutral Zone oil production, shared with Saudi Arabia). Their outcome, however, appears very doubtful.

Most of those plans depend on expanding production from very difficult oilfields, such as the Jurassic Gas Reservoirs, or on Neutral Zone production growth, which will be impossible without the support of international oil companies. For years, a strong political opposition to foreign involvement in the country's oil development has prevented a fixed agreement with international oil companies, thwarting a meaningful launch of "Project Kuwait" (the plan of action originally presented by the Kuwaiti government in 2006 to increase the country's oil production capacity). For example, Royal Dutch Shell signed a contract to raise the production of the Jurassic Gas Reservoir from 50,000 bd to 350,000 bd by 2020, under a formula called "enhanced technical services agreement."[§] Shell is now working on the second phase of the project, but in early 2011,

[§] Like most Technical Service Agreements (TSA), Enhanced Technical Service Agreements (ETSA) do not allow for any foreign control over a country's hydrocarbon reserves, and thus do not permit foreign companies to book reserves. However, ETSA's are more attractive because they allow foreign companies

a parliamentary investigation into its contract once again halted negotiations with IOCs over other oil development projects.

Because of the continuous stop-and-go process over the involvement of foreign oil companies and the apparent difficulty of making decisions in the government, I calculated that Kuwait might get an adjusted additional production of no more than 400,000 bd by 2020, which represents a 60 percent cut to the country's unrestricted additional potential.

Saudi Arabia. Despite the recurring doubts about Saudi Arabia's capacity to maintain its production levels, the Kingdom has always made short work of its critics. In 2006, just as Matthew Simmons' book *Twilight in the Desert* suggested that the country had already surpassed its own peak production capacity, Saudi Arabia announced a plan to increase its production capacity by about 2.5 mbd in four years, an amount equal to the current oil supply of Mexico and Venezuela combined. The plan was carried out smoothly and now the Saudi production capacity (the world's largest) stands at 12.3 mbd (see note at pp. 10-11). An additional plan was discussed to raise this level to 15 mbd, but the steady growth of the global supply capacity has convinced the Saudi government to limit future expansion both for fear of creating excess spare capacity, and—above all—to allocate more spending on social programs and job creation in sectors other than oil, the key preoccupation of the Saudi Monarchy. Consequently, the only project that is now under development concerns the giant Manifa field, which is to commence by 2015, adding 900,000 bd to the Saudi production capacity. Given the progress of the project and the lack of hurdles in bringing it onstream as planned, I did not apply any discount to this figure.

All other programs aim to preserve the current production capacity of the Kingdom, through either new technologies, or better reservoir management methods. In my view, these programs will allow the Kingdom to avoid any significant depletion from currently producing fields until 2020. Significantly, Saudi Aramco, the giant national oil company, stated that enhanced oil recovery technologies would not be necessary to maintain current production levels before 2025.

The United Arab Emirates (UAE). The Emirates are the only country in the Persian Gulf where international oil companies actively participate in the oil sector and may book reserves in joint venture with the affiliates of the national oil company Adnoc, which holds a 60 percent stake in all major concessions. Coupled with the political stability of the Emirates, all this instills confidence in its future oil production increase.

to get higher performance-based payments related to the achievement of pre-determined production targets. In the case of Kuwait's ETSA, an additional advantage is that they do not require the Parliament approval.

Development projects are divided between two main companies: Abu Dhabi Marine Operating Co. (Adma-Opco, owned 40% by BP, Total, and Jodco, and 60% by Adnoc), which holds the concession for major offshore fields, and Abu Dhabi Co. for Onshore Oil Operations (Adco, owned 40% together by Total, Exxon Mobil, Royal Dutch Shell, BP, and Partex), which holds the concession for Abu Dhabi's major onshore fields. Another important company is Zadco (owned 28% by Exxon, 12% by Jodco, and 60% by Adnoc), that operates the giant offshore Upper Zakum field.

The bulk of the unrestricted additional production of the Emirates is targeted in offshore fields, with an overall figure of 620,000 bd. The single largest increase should come from the Exxon-led enhanced oil recovery project in the Upper Zakum field, which will increase its production from 500,000 bd to 750,000 bd by 2015.

As far as the Adco onshore fields, the potential new supply will come from several fields, and amount to 200,000 bd. Adco's 75-year concession expires in January 2014. The UAE government is trying to make agreements with Asian companies to replace the old partners, but this does not seem to affect development projects already underway. A few other development projects will add an additional 40,000-50,000 bd. The total, unrestricted new production is set to reach 860,000 by 2017. I consider this figure to be reasonably accurate and I did not substantially reduce it (only a minor rounding-down), although I did postpone its completion to 2020.

4. ADDING NEW PRODUCTION TO OLD

In addition to the oil coming from new projects, most currently producing countries enjoy a steady supply from their active fields, either due to new technology or better reservoir understanding and management. Consequently, the world's supply capacity by 2020 will also rely upon the resilient production of many "old" oilfields, those that have already reached or surpassed their peak production, but whose decline is slower than expected.

When we balance depletion rates and reserve growth on a country-by-country basis, the decline profiles of older production appear less pronounced than generally expected. As noted in Section 2, the only exceptions to this pattern are Norway, the UK, Mexico, and Iran. Among other traditional producers with more than 200,000 barrels per day of production capacity (which together supply 98 percent of current oil production), there is no country that seems bound to post a net loss of production.

Adding old and new production and adjusting for each single country's depletion rate and reserve growth, I drew up a possible evolution of the world's oil production capacity (crude oil and NGLs) by 2020.

Preliminary results of my analysis point to a strong increase in world's oil production capacity from about 93 mbd in December 2011 to 110.6 mbd in 2020, higher than the increase of each decade since 1980 (See Table 2). As to the composition of this increase, the growth in NGL growth exceeds that of crude oil, because of increased production of liquids from natural gas.

Many variables could influence my findings, and I will address them in Section 10. However, until 2020, the variables that are likely to attenuate an increase in production have a higher probability of occurring than the variables that could accelerate it.

In particular, although I significantly decreased the additional unrestricted production, I consider it unlikely that my revised figures could turn out to be higher; rather, the opposite is possible, because of projects delays, regulatory decisions, lower than expected investments, and political crises.

In any case, the single most important issue that emerges from my analysis is that, from a purely physical and technical point of view, oil supply and capacity are not in any danger. On the contrary, they could significantly exceed world consumption needs and even lead to a phase of oil overproduction if oil demand does not exceed a compounded rate of growth of 1.6 percent each year to 2020.

Table 2: World's Oil Production Capacity to 2020 (mbd)

<i>Country</i>	<i>Production Capacity 2011-end</i>	<i>Additional Unrestricted Production</i>	<i>Additional Adjusted Production</i>	<i>Net Production Additions or Losses*</i>	<i>Production Capacity 2020</i>
Saudi Arabia	12.3	0.9	0.9	0.9	13.2
United States	8.1	7.6	4.7	3.5	11.6
Russia	10.2	1.2	0.8	0.4	10.6
Iraq	2.5	10.4	5.1	5.1	7.6
Canada	3.3	6.8	3.4	2.2	5.5
Brazil	2	6	3.3	2.5	4.5
China	4.1	0.7	0.5	0.4	4.5
Iran	3.8	0.5	0.2	-0.4	3.4
Kuwait	3	1	0.4	0.4	3.4
UAE	2.7	0.86	0.8	0.7	3.4
Venezuela	2.7	2.3	1.2	0.5	3.2
Nigeria	2.4	1.7	0.8	0.4	2.8
Angola	1.9	1.38	1	0.7	2.6
Kazakhstan	1.6	1.6	0.9	0.9	2.5
Qatar	2.1	0.7	0.5	0.3	2.4
Mexico	3	0	0	-0.7	2.3
Algeria	2.1	0.7	0.5	0.2	2.3

Libya**	1	1.2	1.2	1.2	2.2
Norway	2.3	0.4	0.2	-0.4	1.9
Azerbaijan	1.1	0.4	0.3	0.1	1.2
India	0.9	0.6	0.3	0.2	1.1
Indonesia	1	0.4	0.3	0	1
UK	1.2	0.2	0.1	-0.5	0.7
<i>Sub-Total</i>	75.3	47.54	27.4	18.6-	93.9
Others	17.7	2	1.2	-1	16.7
World Total	93	49.54	28.6	17.6	110.6
<i>Of which:</i>					
Crude Oil	78				86
NGLs	15				24.6

*Including depletion and reserve growth

**Libya's 2011 production capacity was curtailed by the Civil War. Before the Civil War, its output capacity stood at 1.9 mbd.

This last point requires a short digression. It is not the purpose of this paper to offer any specific forecast about oil demand. However, it's worth noting that there is constant tendency to overestimate it.

From 2001-2010, world oil demand increased by a compounded average growth rate of 1.4 percent. In that decade, demand faced two years of negative increases in 2008 and 2009, as a consequence of the global financial crisis, and two years of spikes, when it exceeded a 3 percent growth year-on-year: in 2003, due to a recovery after two years of poor increases, and in 2010, when it bounced back after the financial turmoil. In any case, the average growth of demand registered in the 2000s was remarkably similar with that of 1990s.

However, during the first decade of this century most forecasts grossly exaggerated demand growth, feeding the perception that the world's appetite for oil—particularly that of China and other emerging countries—was insatiable. The most relevant source of this overestimation was the most important agency of energy forecasts, the International Energy Agency (IEA).¹⁶ The pattern of overestimation seems bound to be repeated over this decade.

In June 2011, the IEA predicted an increase of global oil consumption of up to 1.3 percent over the next five years, including 2011 and 2012. Yet in 2011, world oil demand grew by 1.1 percent, while looking to 2012, the IEA has already decreased its global forecasts for the third time, envisaging (January 2012) a modest increase of 800,000 bd—or 0.9 percent—to 89.9 million barrels. That is 300,000 less than its previous estimate. Yet, 2012 oil demand will likely be even lower.

In fact, the IEA outlook hinges on a robust increase of 2.8 percent in developing countries offsetting a decline of 0.8 percent in OECD countries. However, even the current engine of world's oil demand growth (China) is facing a decline of economic growth, as are other developing

countries. Moreover, a significant part of Chinese oil demand in the last few months was likely aimed at increasing oil strategic stockpiling in case of an international oil crisis (Iran), rather than at satisfying effective consumption.

Of course, it is possible that sometime in this decade a resurgence of demand could occur, but it is difficult to imagine that the combined average growth of oil demand to 2020 could exceed 1.6 percent – a percentage that would be above the last two decade-long average gain – because of five factors:

- Technology and energy efficiency have consistently reduced the oil input for each unit of GDP.
- Each prolonged period of expensive oil (like the one we have experienced so far since the beginning of the 2000s) led to an increase in efficiency (due to specific legislation and improved technology), that will reduce the specific consumption of oil for each dollar of wealth created.
- The statistics of future demographic trends always seem to feature sustained growth. In reality, developed countries have fewer children and a lower specific consumption of energy for each unit of wealth created, because they can take advantage of new technology and more efficient energy systems. In their turn, developing countries could utilize those technologies and systems to lower the growth of their energy demand.

In other words, we are living in a transformational age where energy efficiency legislation, climate change policies, technological advance, and the dissemination of energy alternatives will reduce the impact of oil in global economies.

Partly reflecting these trends, the IEA long-term forecasts to 2030 entail a combined average growth of oil demand of about 1 percent, split between a higher increase by 2020 and a slower measure of growth from 2021 on. I simply tend to believe that demand will grow at a slower pace in this decade too.

Whatever the case, there is a hiatus between the global perception of oil demand growth, the alarming vision of an insatiable demand for oil promoted by mainstream media, and its effective growth.

As to the latter, this paper indicates that the problems are not beneath the surface, as “peak-oil” theorists suggest, but above it, being critically connected to political decisions and geopolitical risks.

Before concluding this part of my research, I must summarize the assumptions I made for the most relevant countries, starting with the eleven that will provide the majority of future production.

Iraq. The additional new oil production of 5 mbd (considering risk) includes the revamping of already producing fields, which means a zero depletion rate. Thus, considering a production capacity of about 2.5 mbd at the end of 2011 (including the Kurdish region), the production capacity of the country could total 7.6 mbd by 2020.

United States. The additional adjusted production of 4.7 mbd (considering risk) will have to offset a depletion of about 1-1.2 mbd. While NGL production is expected to increase slightly by 2020, crude supply from currently producing U.S. fields will be depleted. Consequently, the net increase of the U.S. oil production by 2020 might be 3.5 mbd.

In 2011, the U.S. liquids (crude oil and NGLs, excluding biofuels) production capacity was about 8.1 mbd (of which 5.6 mbd was crude oil). Adding the 3.5 mbd of new production net of depletion raises U.S. oil production capacity to 11.6 mbd by 2020.

This figure would rank the U.S. with Saudi Arabia and the Russian Federation by 2020, the only three countries producing more than 10 mbd by that time. It would also represent the U.S. historical record in terms of production capacity. If an estimated production of about 1.5 mbd of oil equivalent biofuels is added, the total production capacity of the U.S. could even exceed that of Saudi Arabia.

Finally, it could put a completely new perspective on the U.S. oil imports, which theoretically could come entirely from the Western Hemisphere.

Canada. The additional production of 3.4 mbd (considering risk) will have to offset a huge depletion of 1.2 mbd of conventional oil production (estimated conservatively). This implies that conventional crude will almost vanish from its 2011 level of about 1.3 mbd. In 2011, however, Canada's overall liquid production capacity was 3.3 mbd. Consequently, considering depletion and new supply, its oil production capacity should reach 5.5 mbd by 2020.

Brazil. The additional production of about 3.3 mbd (considering risk) will have to balance the loss of conventional production, which I assess at about 800,000 bd from a production capacity of about 2 mbd in 2011. Thus, the net increase of Brazil's oil production capacity should be 2.5 mbd by 2020, and its total production capacity 4.5 mbd.

Venezuela. According to my estimates, the additional production of 1.2 mbd (considering risk) will have to offset the loss of 700,000 bd of old production, if current policies are not changed. Thus, the result is a relatively modest net increase of only 500,000 bd, which will take Venezuelan overall liquid production capacity to 3.2 mbd.

Nigeria. The additional production capacity of 800,000 bd (considering risk) will have to account for the loss of 400,000 bd of depleted production net of reserve growth. This would bring Nigeria's production capacity to 2.8 mbd by 2020.

Kazakhstan. I have considered a depletion rate near zero, because most oilfields in Kazakhstan have not reached their production plateaus. Adding the additional production of 0.9 mbd to the current 1.6 mbd, the total production capacity of the country should reach 2.5 mbd by 2020.

Angola. The additional production of 1 mbd (considering risk) will have to compensate for the loss of 300,000 bd of old production, a mild depletion that takes into account the emergence of new satellites of currently producing oilfields. Considering Angola's 2011 oil production capacity of 1.9 mbd, this leads to a production capacity of 2.6 mbd by 2020.

Kuwait. Better reservoir management and new technology will allow the country to preserve its current production capacity of 3 mbd, adding 400,000 bd of new capacity (much less than the government target), and putting overall Kuwaiti oil production capacity at 3.4 mbd by 2020.

Saudi Arabia. The current 12.3 mbd production capacity of the country will be preserved thanks to intensive investing in new technology and reservoir management. New production from the Manifa field will put the overall Saudi oil capacity at 13.2 mbd by 2020.

United Arab Emirates. Most projects in the Emirates involve reviving already producing oilfields using IOR or EOR technologies. Consequently, the 800,000 bd of additional, risk-adjusted production is net of increases aimed at maintaining the current production capacity of 2.7 mbd. I conservatively reduced the new production by 10 percent to take into account the irreversible depletion of the already small oil production in Dubai. Consequently, UAE production capacity should reach about 3.4 mbd by 2020. This is a little less than the official target of the Emirates government (3.6 mbd).

As to other significant contributors to the world's oil production capacity by 2020, a handful of countries require comment, starting with those that I think will face a net decline of their current production capacity: Norway, the United Kingdom, Mexico, and Iran.

The cases of Norway and the United Kingdom are not a surprise. For many years now, both countries have struggled against a significant decline in their production, because of the limited size and extensive exploitation of their oil resources. In 2011 they had a combined production capacity of about 3.5 mbd, which might decrease by slightly less than 1 mbd to 2.6 mbd by 2020.

In the past two years, Norway has made important oil and gas discoveries in the Barents Sea area, north of the Arctic Circle, such as Skrugard and Havis fields. Each one is estimated to hold at least 300 million barrels of recoverable oil and gas. According to Statoil, the biggest Norwegian oil

company, the area is a new oil province, with other prospects close to Skrugard and Havis. The emergence of this new oil province might bear surprising results, and at least slow the decline of Norwegian production. However, I only factored in 150,000 bd from the new discoveries, due to the early stage of their exploration and development.

Mexico could lose up to 700,000 bd of its current production capacity of 3 mbd by 2020, with no realistic new developments in sight, except for the attempt to reverse the dramatic decline of the supergiant Cantarell field. The Mexican case, however, is not only an issue of depletion rate, but one of governmental mismanagement of the oil sector and the country's national oil company, Pemex. Things might change in the future, considering that both candidates for the next presidential elections promised to restructure Pemex and open it to the market, following Brazil's Petrobras model. However, I preferred to maintain a conservative approach to the evaluation of Mexican oil future, considering that even in the case of a big change it will take time before it can produce any significant outcome.

The case of Iran belongs to a different category. The country's oil proven reserves rank third in the world, and its production capacity at the end of 2011 was about 3.8 mbd, making Iran the fifth largest oil producer in the world. Yet its international isolation, the lack of advanced technology, and the difficulty for foreign companies to operate in the country cast a long shadow on its future. Most existing analyses forecast a growth of Iranian production capacity to 2020, taking into account its huge potential and projects underway, but I am more pessimistic. Iran's oil sector needs about \$180 billion between 2011 and 2015 to maintain production in declining fields and to add new capacity. In my view, that is simply not affordable for a country at odds with the world and under financial stress from international sanctions and poor economic performance. For these reasons, I assumed that the country will face a steep depletion of about 600,000 bd, only partially offset by a new production of about 200,000 (considering risk), leading to a net production capacity loss of 400,000 bd.

In addition to the production losses in these four countries, the future production of Indonesia is also uncertain. It has been losing supply capacity for many years. Yet several development projects now underway might reverse that trend and slightly increase the country's potential by 2020.

Other important producers deserve some detail.

The Russian Federation has continued to surprise everyone but a handful of experts with the steady increase of its oil supply capacity. As explained in Section 1, even if several Russian large producing fields are in decline, particularly in the still dominant West Siberian Basin, oil companies have demonstrated that their re-development may still generate increasing supplies of oil, both through drastically cutting decline rates, and by enhancing recovery rates that are still relatively modest—an average of 20 percent.¹⁷ This involves the extensive use of sophisticated

knowledge and technologies that, in turn, are critically linked to fiscal incentives, such as tax breaks and lower export duties. Recently, the Vice President of Lukoil, the largest Russian oil company, stated that “the country could squeeze an extra 30 billion barrels from mature fields in West Siberia if it could match U.S. onshore recovery rates.”¹⁸

The same is true for new projects, like the Vankor and Uval group of fields in East Siberia, which are increasing production, and other projects in the same region. So far, East Siberia is the only region benefitting from strong fiscal incentives, although in 2010 they were cut back (specifically, the government cancelled the initial zero export duty on East Siberia’s oil production).

In my analysis, I assumed that any decrease in production—or any perceived threat to it—would compel the Russian government to modify its fiscal approach to keep the country from losing its position among the most powerful oil countries and the political leverage that comes with that. The hydrocarbon potential of the Russian Federation is still huge, and it plays such an important role in keeping the country’s superpower status alive that it is improbable that the government would put it at risk, particularly after the re-election of Vladimir Putin. In fact, on April 2012 Putin announced a new fiscal incentive package to spur the development of Russian offshore hydrocarbon resources.

In any case, the assumptions I made in Table 3 are not particularly bullish, and do not take into account a full-fledged oil-friendly fiscal reform.

China is a complicated puzzle. The country has achieved significant expertise in recovering more oil from its mature fields, and its companies have aggressive domestic exploration plans, focused on widening the existing resource base of already producing fields, searching for new fields, and tapping unconventional resources, including shale/tight oil and gas. The assumptions in Table 3 do not consider unconventional oil, which could represent another unexpected outcome of China’s rush to the frontier of the energy spectrum.

India, another growing oil consumer, is posting steady increases in liquid production, mostly concentrated in NGLs. The major sources of growth that I considered for this paper are the re-development of the Mumbai High oilfield, the start of the Mangala field, and the development of the Krishna Godavari Basin.

Finally, I will address Libya. After the dramatic drop in oil production from 1.9 mbd to about 400,000 bd during the Civil War, the country’s output is recovering much faster than most anticipated. Political and fiscal uncertainties, however, still loom large on the future oil capacity of the country. I estimated oil capacity of 2.2 mbd by 2020, based on a full recovery of the existing oilfields and their upgrade, according to previously established plans. If the country achieves political stability and improves the fiscal terms for exploration and development, the 2.2 mbd capacity level could easily be surpassed. However, the opposite is also true: the lack of political

stability, an outburst of security problems, and the lack of fiscal incentives could endanger the full recovery of existing oil production base.

II. THE U.S. SHALE/TIGHT OIL

5. FROM SHALE GAS TO SHALE AND TIGHT OIL

As noted in Section 1, a process of “*de-conventionalization*” of the oil supply is taking place; its center of gravity is the Western Hemisphere.

The growing output of Canadian tar sands, the huge ultra-heavy oil resources of the Venezuelan Orinoco Belt, and the recent discoveries of Brazil’s ultra-deep offshore pre-salt formations, are all pieces of the unconventional oil mosaic that, by 2020, could deliver more than 10 mbd from the Western Hemisphere alone.

Yet the most surprising and fastest-growing frontier of unconventional oils is that of the shale and tight oil in the United States.

“Shale oil” is also referred to as “tight oil,” although they are not exactly the same thing. It is more important, however, not to confuse “shale oil” with “oil shale,” as often occurs.

Put simply, “shale and tight oil” are conventional oils (light oils with low sulfur content) trapped in unconventional formations, which make it extremely difficult to extract hydrocarbons. By contrast, “oil shale” is a precursor of oil called *kerogen*, a sort of *teenage-oil* that constitutes the building blocks of conventional oil. Oil shale is trapped in rocks with low porosity and permeability, making the extraction of kerogen difficult. However, the oil shale rocks are closer to the surface than those containing shale and tight oil. Thus, both the oil shale formations that contain kerogen and the kerogen itself are “unconventional.”

The U.S. holds huge oil shale resources, particularly in the Green River Formation of western Colorado, Utah, and Wyoming. The problem with oil shale is that it requires major heating and processing to become usable fuel, much like what it is necessary to obtain oil from Canadian tar sands. However, extracting oil shale costs more than manufacturing most Canadian sands. Add the cost of processing the kerogen and oil shale becomes too expensive, at least for now.¹⁹

Shale oil reservoirs are rich with clay and fissile, meaning they split in layers where the presence of clay stone is massive. These layers may stretch horizontally for hundreds and thousands of miles. Unlike shale formations, tight oil formations are made of siltstone (a mixture of quartz and other minerals, predominately dolomite and calcite, but many others may be present) or mudstone without a lot of clay in the reservoir. Most tight oil formations look like shale oil ones on data logs, hence the continued reference to both as “shale.” For consistency, I will generally use “shale formations,” and “shale plays,” or “shale/tight oil” plays and formations in this paper,

We have known about the existence of huge shale oil formations in the United States for decades, but high cost and various technological barriers made development impossible. Paradoxically, oil shale plays received much more attention until a few years ago, especially after the oil shocks of the 1970s, because they appeared more accessible than shale formations. Oil shale plays lie near the surface, while shale oil formations may reach 15,000 feet or more.

At the beginning of this century, however, the situation altered radically, when increasing oil prices made it cost-effective to use advanced technologies to extract shale and tight oil. Those technologies are horizontal drilling and hydraulic fracturing, the fracking/fracing (also “frac” in oil jargon) that enabled the shale gas revolution in the U.S.

Horizontal drilling and hydraulic fracturing are often referred to as “new” technologies, but this mistake contributes to the skepticism and open criticism surrounding their use. The first horizontal well in history was completed in Texon, Texas, in 1929. At that time, it proved to be an imperfect and costly technology, useless in a world of falling oil prices. It took about five decades before horizontal drilling finally established itself as a commercially viable technology in the early 1980s, thanks to both dramatic increase of oil prices following the 1970s shocks, and the significant improvements in downhole drilling and telemetry. Since then, horizontal drilling has been widely used by the oil industry.

Hydraulic fracturing, the most controversial technique used for both shale gas and shale oil extraction, was first used in 1947 in Grant County, Kansas. According to a report by the National Petroleum Council (2011), “By 2002, the practice had already been used a million times in the U.S.” The same report stated that in 2011, up to 95 percent of wells drilled in the U.S. were hydraulically fractured, accounting for 43 percent of U.S. oil production and 67 percent of U.S. natural gas production.²⁰

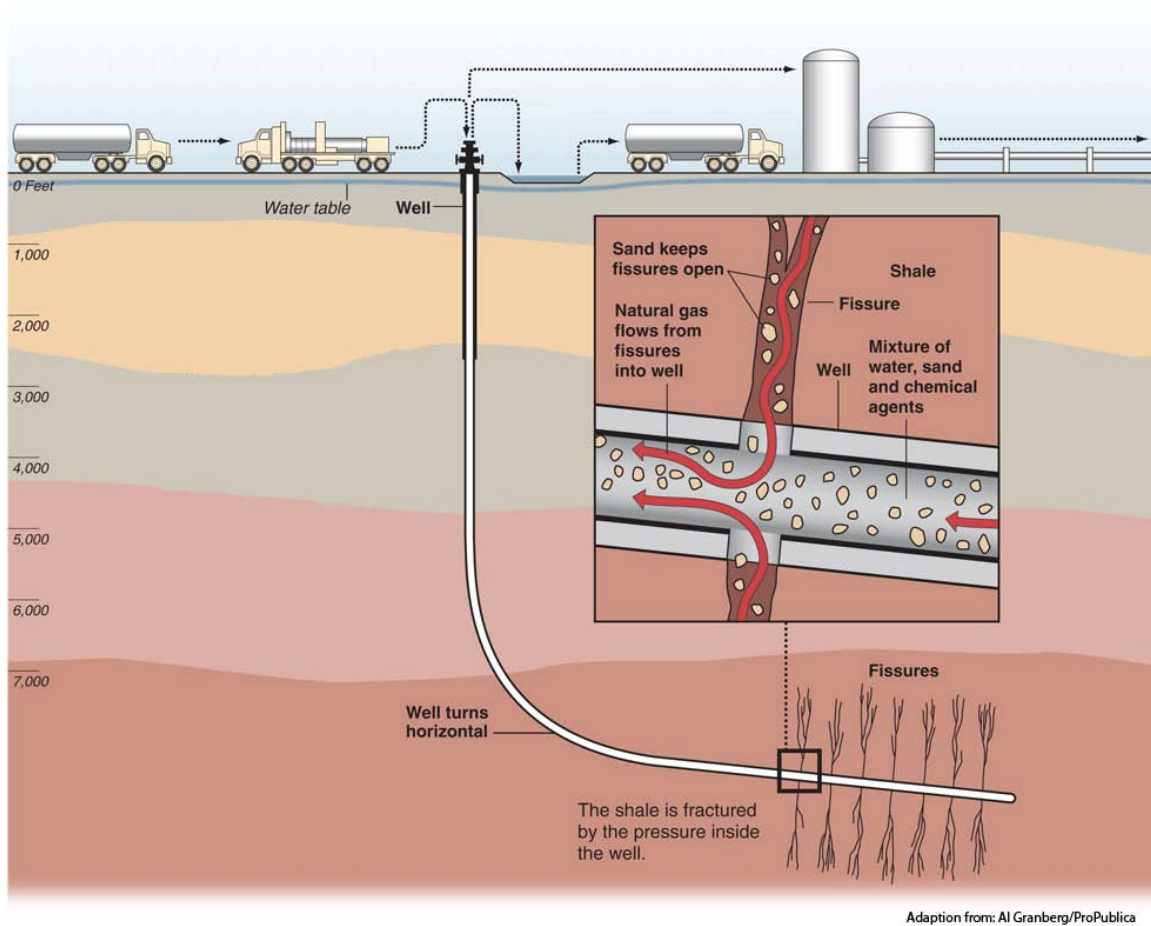
Thus, far from being new, hydraulic fracturing involves some controversial practices that have been introduced to the public only in the last few years following the U.S. shale gas boom. Yet hydraulic fracturing is not limited to the extraction of oil and gas: for example, in the U.S., it is widely used in wastewater disposal.

The combination of horizontal drilling and hydraulic fracturing is a complex process that requires a short explanation.

In horizontal drilling, a well is vertically drilled for thousands of feet into the earth, then turned horizontally to reach the hydrocarbon reservoirs. While the well is being drilled, a protective steel pipe (casing) is inserted in the wellbore. This pipe is perforated within the target zones that contain oil or gas. At this point, hydraulic fracturing may start.

Fracking involves pumping (through horsepower machines, usually pumping trucks at surface) a mix of fluid (water), sand (proppant), and chemicals down the perforated still pipe and into the reservoir at ultra-high pressure to create small fractures in shale/tight formations which free up the oil and gas to flow up the well. Sand prevents the fractures from closing when the injection is stopped (other kinds of proppants may be used, such as ceramic, that many experts consider more effective), while chemicals serve to tailor the injected material to the specific geological situation, protect the well, and improve its operation. Once the fractures have been created, injection ceases and the fracturing fluids begin to flow back to the surface—as shown in Figure 4.

Figure 4: How hydraulic fracturing works



Horizontal fracking operations occur in multiple stages, sometime every 300 feet along the horizontal (lateral) arm of the wellbore, and each stage involves the repetition of pumping sand, water, and chemicals in a specific section of the well. Multiple fracking stages allow for a dramatic increase.

The first large scale, combined application of horizontal drilling and fracking of shale formations occurred in Barnett Shale (a tight gas formation), Texas, in 2000, pioneered by a small U.S.

company, Mitchell Energy.²¹ That initial experiment was the catalyst for the U.S. natural gas revolution, which went unnoticed and underestimated for many years even though its results were already clear. It is worth remembering this underestimation, because it seems to be happening again with shale oil.

From the mid-1990s to 2009, most experts believed that the U.S. would become a great natural gas importer, due to the steep decline of its domestic production of methane, the main component of natural gas. No one either anticipated or recognized the shale-gas revolution as it was taking place, and even most industry leaders considered it a temporary bubble bound to evaporate quickly for several reasons, such as high extraction costs, poor estimates of recoverable shale gas, steep decline of well productivity after a rapid output increase, and many more. It took at least nine years after the early stages of development of Barnett shale before the big oil companies jumped on the shale gas wagon by paying exorbitant amounts of money to buy either small shale gas players, or pieces of acreages and working interests of other companies. Similarly, between 2008 and 2009, the USGS, EIA, and the Potential Gas Committee significantly increased their estimates of the recoverable natural gas resources of the United States. Yet, shale gas production exceeded even those amendments, jumping from virtually zero in 2000 to more than 130 billion cubic meters in 2011, contributing to a dramatic decrease of natural gas prices in the U.S. and structurally changing the perception of the country's natural gas future. Shale oil seems to be repeating this trajectory.

Most official estimates of U.S. shale oil plays are backwards, based on a few drilling wells measured during the very early stages of development of those plays. On its website, for example, the U.S. Energy Information Administration offers a January 2009 estimate of a few shale plays, based on research made in the previous years—when most U.S. shale plays were just approaching their first drilling tests.²² In addition, the U.S. Geological Survey has produced outdated evaluations on shale oil plays that the rapid evolution of the U.S. shale oil has contradicted.

It is worth noting, however, that assessing the producible reserves of a shale/tight oil formation is much more complicated than evaluating conventional oil resources (that is not easy at all!).

Each shale formation is different, and the properties within an individual field (porosity, permeability, etc.) can sometimes vary from well to well. Consequently, the assessment of both the recoverable resource in a single field as well as its productivity over time requires a highly customized analysis.

In general terms, it takes the drilling of a few wells to assess the recoverable oil from a conventional field, although that initial estimate could change over time due to additional drilling activity, the extension of drilling to other areas of the field, the improvement of the field's geochemistry and physics knowledge, and the advent of new technologies. What's more, a

conventional producing well may produce oil for years once completed. On the other hand, the huge differences in permeability, porosity, and thickness of a shale/tight oil formation require many more exploration wells be drilled in different areas of the field before making it possible to have an idea of the effective recoverability rate from the whole formation. The rapid output increase and decline of shale/tight oil producing wells further complicates matters, which makes shale/tight oil operations a “drilling-intensive” activity. In other words, it requires continuous drilling of new wells for maintaining and increasing production. For these reasons, it is impossible to make any reasonable evaluation of the future production from a shale/tight oil formation based on the analysis of a few wells data and such limited activity.

Despite their complex features, most of U.S. shale and tight oil are profitable today at a price of oil (WTI) ranging from \$50 to \$65 per barrel, thus making them sufficiently resilient to a significant downturn of oil prices (for conservative reasons, however, I used a long-term price of WTI of \$70 per barrel to make my evaluations about the future U.S. shale/tight oil production).

Before examining the extent of the shale/tight oil revolution in the U.S., it is worth noting that it is not only the result of a huge resource endowment, but it also stems from the uniqueness of some features of the U.S. oil industry and market, which make it difficult to be replicated in other areas of the world – at least in a short period of time.

First of all, in the U.S., individuals and companies may own property rights on mineral resources, while in most parts of the world these rights belong to states only. This fact gives a huge incentive to land owners to lease their property rights and to the oil industry to lease or buy them.

Another major feature of the uniqueness of the U.S. and Canada is the presence of thousands of independent oil companies, ranging from very small to multibillion companies, that historically played the role of pioneering new frontiers.

The strategies and business models of these independent companies are usually much different from those of the large, integrated multinational oil companies, and require a short digression.

Oil independents typically search for high risk-high reward opportunities whose potential is uncertain and whose initial development cannot comply with the rigid financial criteria used by big oils for taking investment decisions. Moreover, most of these companies, oftentimes owned by a single person or a small group of partners, are mostly focused on cash flows and growth, rather than profits and high profitability, at least in the first stages of their development.

As long as they are successful in their undertakings while being cash-positive, they will succeed in getting the money they need to grow their business. Eventually, they can decide to sell their entire business to larger independents or bigger oil companies, as well as to go public. Their time-frame for success, thus, is much shorter than that of big multinational oil companies: they

couldn't afford to be cash-negative for long periods of time, otherwise their investors could stop supplying money; they cannot be unsuccessful in their growth-strategies, otherwise they cannot make money by selling part (of all) of their equity.

Although highly innovative, then, oil independents usually do not engage in proprietary technology development (an exception is represented by larger independents), but they apply or adapt existing technologies in innovative ways to new targets, improving their processes and applications, thanks to the help of oil service companies (such as Halliburton or Schlumberger) that are the real owners of technological know-how in the oil and gas sector.

Another feature of the U.S. (and Canada) oil and gas sector is the presence of several financial institutions, funds, capital ventures, equity firms that are eager to fund independent companies, oftentimes by becoming their equity partners.

A final, unique feature of the U.S. (and Canadian) hydrocarbon arena is the broad availability and flexible market of drilling rigs and other essential tools of oil exploration and production. For instance, the U.S. and Canada have about 65 percent of all drilling rigs existing in the world.

All these features are foreign to other parts of the world, and they make the U.S. and Canada a sort of unique play for experimentation and innovation, such in the case of U.S. shale oil and gas or Canadian tar sands.

6. HERALD OF THE REVOLUTION: THE BAKKEN SHALE CASE

The most important frontier of shale oil development so far is the Bakken Shale, a tight oil formation (not actually shale) mostly composed of silt and sandy silt.

The Bakken Shale is part of the Williston Basin, a huge sedimentary basin that stretches about 300,000 square miles across North Dakota, South Dakota, and Montana in the U.S., and Saskatchewan and parts of Manitoba in Canada. The Williston Basin includes other shale formations, such as Three Forks, Tyler and Spearfish.

First discovered in 1951 in North Dakota, the Bakken formation (about 200,000 square miles, or 520,000 km²) was too costly to develop for many decades. Only at the beginning of the 2000s, the small Lyco Energy Company and giant Halliburton attempted a combination of horizontal drilling and hydraulic fracturing in a small section of Montana's part of the formation (the *Elm Coulee field*). The outcome was so promising²³ that it led the independent company EOG Resources to repeat the experiment in 2006, in the North Dakota section of the Bakken formation (the *Parshall field*). That was the real beginning of the shale oil revolution.

Thanks to the Bakken Shale, oil production in North Dakota skyrocketed from around 110,000 bd in 2006 (of which 7,600 boe/d in the Bakken Shale) to nearly 264,000 boe/d in 2010 and more than 530,000 barrels in December 2011.²⁴ At this time, its monthly record continues to exceed expectations. Meanwhile, the progressive exploration of the area activated the development of the Three Forks shale (another tight oil formation), which also appears to have huge resource potential.

Before assessing what is happening in Bakken on a deeper level, we must look into the existing geochemical evaluations of that formation. In 1999, Leigh Price, a USGS geochemist who devoted his life to studying the Bakken shale, completed the most comprehensive assessment of the Bakken resource. Unfortunately, Price died before his study could be peer-reviewed, so it was never published and its results were ignored or neglected. Only later did the University of North Dakota obtain a copy of the Price study, which is now available on the University's Energy & Environmental Research Center website.²⁵

In addition to an unparalleled detailed analysis of the Bakken formation (based on extensive data and analysis of core-logs) Price's conclusions seem to be highly consistent with the unexpected production boom recorded in the Bakken field from 2010 onwards.

Price estimated the total amount of the original oil in place (OOP) in the Bakken shale to be between 271 billion and 503 billion barrels, with a mean of 413 billion barrels.²⁶

Although the Price's figures are immense, a February 2012 assessment by Continental Resources (an independent company leading the development of Bakken) surpassed them. Continental estimated that the combined Bakken-Three Forks formations hold about 900 billion barrels of OOP.²⁷ In 2011, Continental has estimated the Bakken OOP alone at 500 billion barrels.

In terms of oil in place (not all of which is recoverable), both the Price and the Continental estimates *would put the Bakken formation ahead of the largest oil basins in the world, making it the biggest one—a sort of Saudi Arabia within the United States*. (In 2005, Saudi Oil Minister Al Naimi publicly estimated the OOP of Saudi Arabia to be around 700 billion barrels).²⁸

According to Price, about 206 billion barrels of the Bakken OOP was recoverable at a cost of less than \$12 per barrel. At that time (1999), this was a relatively high cost of recovery compared to an average recovery cost of \$7 per barrel worldwide.²⁹ Continental Resources has not released a new assessment of the recoverable oil in Bakken/Three Forks since its 2012 assessment of OOP. In 2011, it estimated Bakken recoverable oil at 20 billion barrels. The CEO of Continental, however, stated that the Three Forks formation had the potential to double the recoverable reserves of the Bakken play.³⁰

Over time, other geological studies have offered different evaluations of the Bakken OOP. In particular, Schmoker and Hester (1983) estimated that the Bakken might contain 132 billion barrels of oil in North Dakota and Montana.³¹ Meissner and Banks (2000) estimated oil in place at about 32 billion barrels.³² Flannery and Kraus (2006 and later update) initially estimated the Bakken resource at 200 billion barrels using a sophisticated computer program with extensive data input from the North Dakota Geological Survey.³³ Eventually, they revised their earlier assessment, upgrading the estimate of Bakken OOP to 300 billion barrels.

In April 2008, a report by the North Dakota Department of Mineral Resources (NDDMR) estimated that the North Dakota portion of the Bakken contained up to 167 billion barrels, and that approximately 2.1 billion barrels of that oil (the estimated ultimate recovery), less than 2 percent, could be recovered using 2008 technology. In any case, the report also recognized that technological evolution could dramatically increase the recovery factor.³⁴

All these figures are in sharp contrast to a 2008 U.S. Geological Survey assessment of the Bakken Shale, that estimated 3.0 to 4.3 billion barrels of undiscovered, technically recoverable (not economically recoverable, necessarily) oil in the portion of the Bakken formation stretching from Montana to North Dakota alone.³⁵ The USGS assessment represented a 25-fold increase in the amount of recoverable Bakken oil compared to a USGS 1995 estimate, which set the amount at 151 million barrels of oil. The huge variation between the two assessments and some technical questions concerning the 2008 study raise serious doubts about the validity of that assessment.

In particular, the USGC concluded its analysis of per-well recovery in Bakken in July 2007, when drilling rigs in the region were few and recovery rates were modest because of the early learning curve concerning the whole formation: horizontal drilling-hydraulic fracturing was tested only a year before. Since then, however, the activity in Bakken has exploded, as demonstrated by the drilling-rig count in the play.

On a weekly basis, there were around 50 active drilling rigs in the Bakken Shale between 2006 and early 2008, almost equally divided between Montana and North Dakota. They jumped to about 90 in early 2008, and then diminished to less than 40 in mid-2009. But at the beginning of February 2012, there were 200 active drilling rigs, 183 of which in North Dakota alone,³⁶ and a total of about 6,000 producing wells, compared to less than 100 in July 2007, when the USGS ended its analysis. In the same timeframe, observed ultimate recovery rates have dramatically increased, jumping from 50,000-100,000 estimated ultimate recovery (EUR) barrels per well in 2007 to 600,000-800,000 EUR barrels per well in 2011.³⁷

The North Dakota Industrial Commission has recognized the improved well EUR as well as the Three Forks potential, and in January 2011 announced that recoverable reserves from the Bakken-

Three Forks reservoirs could reach 11 billion barrels in North Dakota alone. That is five times the NDDMR 2008 estimate of 2.1 billion barrels of OOP in just the North Dakota section of Bakken.

As noted in Section 1, the science of estimating existing underground resources is uncertain and dynamic. Evaluations evolve over time due to better knowledge, improved technology, the price of the estimated resource, the estimated cost of its extraction, and the progressive development of the estimated field/basin. All these factors affect the estimate of economically recoverable oil (or other mineral resources) from a given basin. The knowledge of the original oil in place improves as well over time because of better knowledge and improved instruments of research and exploration.

For example, in the case of most shale oil formations, many believed that the oil molecule, usually large at 0.5 nanometers or more, was too big to flow through the minuscule pores (usually smaller than 0.1 nanometers) between the rock particles that are typical of shale/tight oil formations. After the exploration boom of the last few years, we now know what Leigh Price had already observed: the Bakken formation and other U.S. shale/tight oil formations are fairly porous and permeable, which allows oil to flow through the rock and be recovered.

It is highly probable, thus, that the current boom in Bakken production will lead to new geological evaluations and augmented numbers, closer to Leigh Price's figures.

In fact, the growing availability of well and core log analyses* reveals that Bakken and Three Forks holds huge volumes of liquid that can be profitable with a price of oil lower than \$70 per barrel under current conditions. The solution of the takeaway problem (inadequate transportation pipelines and refining capacity—see Section 8), the decrease of costs per well with improved knowledge and drilling times, the addition of necessary supplies (e.g., fracking horsepower and sand), and the gradual increase of long-term infrastructure may significantly lower the cost of extracting oil from the formation (which is currently breaking even).

In general, the initial phase of development of an oil basin involves much higher costs because of the lack of basic facilities, pipelines, labor force, housing, etc. Moreover, unconventional plays like Bakken require much higher development costs, because of the lack of knowledge and uniform production standards. The more a basin is developed, the more the infrastructure is strengthened, the more the proficiency increases, and the more the overall costs decrease.

* Well logging is the process of recording various physical, chemical, electrical, or other properties of the rock/fluid mixtures penetrated by drilling a well.

Several factors still prevent a comprehensive understanding of the formation secrets, leading to different and sometimes conflicting views about the best way to increase recovery or decrease costs. These include: the lack of uniformity in different areas of the Bakken play, the still experimental stage of development in the whole formation, and the presence of dozens of small to medium independent companies, each one trying to find its way. Determining a production strategy can also prove highly subjective, as the beliefs of men in the field influence the process.

For example, several wells in the Bakken are now drilled horizontally with record-length laterals, more than 10,000 feet, and record multistage fracking operations along a single lateral, more than 30 stages.³⁸ Nothing of that kind has ever been seen in the shale gas development, where laterals are generally no longer than 5,000 feet with no more than 12-14 fracking stages along the same lateral.

Mark Papa (the CEO of EOG Resources) summed up the reasons for this complexity when he stated that in Bakken “reserves are a linear function of the lateral length. If you drill oil with twice the lateral length, you’re likely to get twice the reserves.”³⁹ Yet, because of the complexity and differences concerning any shale formation, other companies and technicians may hold various views, depending on the specific part of the formation they are operating.

Based on these factors and an extensive analysis of well and core data coming steadily from the Bakken operating companies, I consider that future production growth in the Bakken has been largely underestimated. The basic assumptions on which I based my evaluation of the Bakken Shale unrestricted additional production by 2020 are as follows:

- A price of oil (WTI) equal to or greater than \$ 70 per barrel through 2020;
- A constant 200 drilling rigs per week;
- An estimated ultimate recovery rate of 10 percent per individual producing well (which in most cases has already been exceeded) and for the overall formation;
- An OOP calculated on the basis of less than half the mean figure of Price’s 1999 assessment (413 billion barrels of OOP, 100 billion of proven reserves, including Three Forks). Consequently, I expect 300 billion barrels of OOP and 45 billion of proven oil reserves, including Three Forks;
- A combined average depletion rate for each producing well of 15 percent over the first five years, followed by a 7 percent depletion rate;
- A level of porosity and permeability of the Bakken/Three Forks formation derived from those experienced so far by oil companies engaged in the area.

Based on these assumptions, my simulation yields an additional unrestricted oil production from the Bakken and Three Forks plays of around 2.5 mbd by 2020, leading to a total unrestricted production of more than 3 mbd by 2020.

7. A BROADER VIEW OF THE U.S. SHALE/TIGHT OIL POTENTIAL

The Bakken and Three Forks are not isolated cases in the United States, but only the beginning of a revolution that will include other top shale/tight oil plays in the U.S.

There are at least twenty big shale/tight oil formations in the United States, some of them already under early, rapid development, such as the Eagle Ford Shale in southern Texas (western Texas Basin), others in an embryonic stages of drilling, such as the Niobrara Shale mainly in Colorado, the Utica Shale in the Northeastern U.S. (mainly in Ohio), and the huge Permian basin under Texas and New Mexico, which contains at least six big shale plays: Avalon shale, Bone Spring Shale, Leonard Shale, Spraberry Shale, Yeso, and Wolfcamp.

Unfortunately, the recent development of these plays makes assessing them even more complicated than the Bakken. EIA and USGS data are backward and particularly poor, while data from oil companies operating in those plays are still too fragmented and subject to constant increases, making it difficult to reconstruct a broader view of their potential resources and future production. To my knowledge, there exists no extensive and comprehensive geological analysis for other shale oil plays, like the one that Leigh Price conducted on the Bakken Shale.

All these elements serve as a disclaimer for the analysis that follows, which is limited to those shale oil plays for which a significant data flow is emerging.

The immediate successor of the Bakken exploit is the Eagle Ford Shale in the Western Texas Basin, another tight oil play that stretches more than 300 miles (480 kilometers) from the Mexico border south of San Antonio to northeast of Austin. The first horizontal drilling on Eagle Ford shale was done in 2007, but commercial evidence came out only in October 2008, when Petrohawk, an American exploration and production company, was drilling in the midst of the global financial crisis and falling oil prices. Consequently, there was little action until 2010, when new discoveries and unexpected recovery rates similar to those in the Bakken finally attracted an eager crowd of oil and gas independent companies. Activity in the field has even surpassed Bakken; 248 active drilling rigs (April 2012), compared to 200 rigs in the U.S. section of the Bakken.⁴⁰ Even more impressive is the crude oil production of Eagle Ford: starting from virtually zero in 2009, it averaged 190,000 bd in 2011, and passed 300,000 bd in December 2011, when it also produced 1.7 Bcfd of natural gas, both wet and dry, for a total of about 600,000 bd of oil equivalent, and about 420,000 bd of total liquids (crude oil and NGLs).⁴¹

Official EIA and USGC estimates of Eagle Ford's OOP and technically recoverable oil are highly conservative, approximately 3 to 4 billion barrels. However, each year, most oil companies operating at Eagle Ford increase their own estimates of the play's hydrocarbon resource, as a consequence of the progressive deployment of their drilling activities.

One of the most significant examples of this upward revision-trend comes from EOG Resources, the largest acre-holder in Eagle Ford Shale with about one million acres leased so far (March 2011). In 2011, EOG estimated the recoverable hydrocarbon resources in the roughly 550,000 acres the company held at that time at Eagle Ford at 900 million barrels of oil equivalent (MMBoe), of which 690 million barrels of oil, 100 million barrels of natural gas liquids, and 661 Bcf of natural gas. All these figures were "net after royalty", meaning that they were about 20 percent (or 180 MMBoe) lower than the actual figure. By 2012, EOG had increased its estimated potential reserves in the Eagle Ford from 900 MMboe to 1,600 MMboe net after royalty, a 78 percent increase. That estimate was based on a 6 percent recovery rate. EOG's acreage is only a fraction of the whole Eagle Ford formation.⁴² Petrohawk Energy has reported a figure of 340 million barrels of recoverable liquids (crude oil and NGLs) for the 360,000 acres it holds that does not overlap with the EOG acreage. In 2012, another big Eagle Ford operator, Pioneer Natural Resources, estimated that the shale formation contains as much as 25 billion barrels of recoverable liquids alone, in addition to around 150 trillion cubic feet (Tcf) of natural gas.

Meanwhile, estimated ultimate recovery rates at Eagle Ford have dramatically increased too, and now range between 400,000 to 600,000 barrels per well, suggesting an overall recovery from the field well in excess of the 3 to 4 billion barrels estimated by EIA and the USGS.⁴³ These figures are bound to increase over the next few years, but right now, many experts suggest that Eagle Ford may be even larger and more prolific than the Bakken Shale.

For the purposes of this paper, I chose a bottom-up approach to assess the producible liquids from Eagle Ford by 2020, considering more than 100 well-by-well reports from operating companies related to different sections of the field, observed ramp-up, depletion, recovery rates, etc. I also took the EIA and USGS evaluations as a starting point, although highly conservative and outdated, and tested them against the evolution of the activity in the Eagle Ford area.

As a result, I concluded that the Eagle Ford shale might reach an unrestricted production of liquids in this decade of about 2.5 mbd, or additional unrestricted production of 2.1 mbd above its current level, for a total of about 15 billion barrels of recoverable liquids. This figure seems more consistent with the actual data coming out of the play.

One competitive advantage Eagle Ford has over other U.S. oil shale plays is its geographic location near the Gulf coast, home to the largest and most complex oil transportation and refining infrastructure in the United States. This means that the takeaway problems affecting the Bakken

(and western Canadian) supply will diminish as Eagle Ford production increases, and virtually non-existent from 2013 on, as new pipelines start operating. The low cost and short time for transportation to the Gulf Coast refining complex will likely make Eagle Ford's shale oil the most competitive American shale oil. What's more, Eagle Ford tight oil production results to be cheaper than Bakken's, being profitable at oil prices ranging between \$50 and \$65 per barrel.

Close to the Eagle Ford shale are the shale plays that are part of the huge Permian Basin. So far, the most relevant production prospects have come from the Wolfcamp and the Bone Springs shale plays, but activity is rapidly surging throughout the Permian Basin shale plays. From a handful of horizontal drilling rigs in 2010, the count had escalated to more than 160 by early 2012.

The Permian Basin area has a long history of conventional oil and natural gas production that dates back to the 1920s. Its conventional hydrocarbon supply peaked in the early 1970s, and faced a steady decline to the present. This means that the whole area is better positioned in terms of infrastructure and transportation systems, even though most of them are outdated and need to be replaced to accommodate the surge of shale oil production that will likely occur over the next few years.

I analyzed the future potential output of the Permian Basin using the same approach applied to Eagle Ford and data from more than 70 wells in different areas of the field. I tested the data against the outdated EIA assessment of recoverable reserves of about 4 billion barrel of liquids. The result was unrestricted, additional production of about 1 mbd from the entire Permian shale plays by 2020, dramatically reversing the decline of the entire basin conventional production. Because of shale oil, the Permian basin could deliver a total production of 1.6-1.7 mbd in 2020 (with conventional production ranging between 600,000 and 700,000 barrels per day). My assessment is slightly lower than the one released by Deutsche Bank Research in February 2012.⁴⁴

Two other shale oil hot spots are the Utica Shale, and the Niobrara and Codell Shales.

Utica Shale is a massive shale rock formation that lies below the Marcellus shale. The epicenter of its development is now in Ohio, but the whole formation stretches under eight states, from Tennessee to New York, and across the border into Quebec. Rich in carbonate content, Utica Shale is particularly well suited for hydraulic fracturing, which breaks carbonate rocks more easily, releasing greater quantities of oil and gas.

The most active company in the Utica Shale is Chesapeake Energy, which has acquired over 1.25 million acres in the Ohio section of the shale so far. According to the CEO of Chesapeake (Aubrey McClendon), the company has estimated that the Utica Shale is one of the biggest oil discoveries in U.S. history, with more than 25 billion barrels of oil, as well as trillions of cubic

feet of natural gas. Even the more conservative figures of the Ohio Geological Survey point to a highly significant 8.2 billion boe for the Ohio section alone, of which about 5.5 billion barrel are liquids.⁴⁵ However, the results of the five horizontal drilling tests conducted so far (February 2012) do not support a well-grounded assessment of the potential supply of the formation.

This is also the case with the Niobrara and Codell Shales, both part of the Wattenberg basin located mainly in northeastern Colorado. The most up-to-date figures (November 2011) for Niobrara/Codell come from the first 11 horizontal wells drilled by Anadarko Petroleum, the current leader in the area. They show an initial production ranging from 555 to 1,505 boepd, similar to the initial production figures at Bakken and Eagle Ford, with almost 70 percent liquids. Based on these elements, Anadarko has devised an aggressive development plan aiming to recover up to 1.5 billion boe in its acreage alone, with a 70 percent liquid ratio. Anadarko also estimated initial well costs of around \$4.5 million, far less expensive than in Bakken.⁴⁶

Considering the scarce data available for both Utica and Niobrara/Codell Shales, I could not model the evolution of future liquids production. However, according to a probabilistic method (with a ± 50 percent probability ratio), total unrestricted production from those formations could reach 400,000 bd by 2020.

For the purposes of this paper, my probabilistic method (production from yet-to-find-discoveries) accounted for potential supplies from other U.S. shale/tight oil plays. I preferred to maintain a conservative approach to the issue, using an unrestricted, additional production from other sources of 500,000 bd.

In sum, the combined liquid additional unrestricted production from the shale/tight oil formations I considered (Bakken/Three Forks, Eagle Ford, Permian Basin, Utica, and Niobrara/Codell) and other shale/tight oil plays could reach 6.6 mbd by 2020, assuming (as in the Bakken case) a price of oil equal to or greater than \$70 per barrel through 2020, although in most cases shale/tight oil production appears to be profitable with an oil price ranging from \$50 to \$65 per barrel.

However, although my analysis suggests that the resource base is huge and its extraction cost is sustainable, I see problems that could significantly reduce the potential output of U.S. shale plays. I address them in the next two Sections. I estimated conservatively that those problems could reduce unrestricted, additional U.S. shale and tight oil production by 30-50 percent (depending on the different plays), implying an additional supply of 4.17 mbd by 2020 (Table 3).

Table 3: Additional production from U.S. shale/tight oil plays by 2020 (million barrels per day)

Shale play	Additional, unrestricted production	Additional adjusted production
Bakken/Three Forks	2.5	1.5
Eagle Ford	2.1	1.47
Permian	1	0.7
Utica	0.2	0.1
Niobrara/Codell	0.2	0.1
Others	0.6	0.3
Total	6.6	4.17

8. THE PROBLEMS LOOMING OVER U.S. SHALE OIL

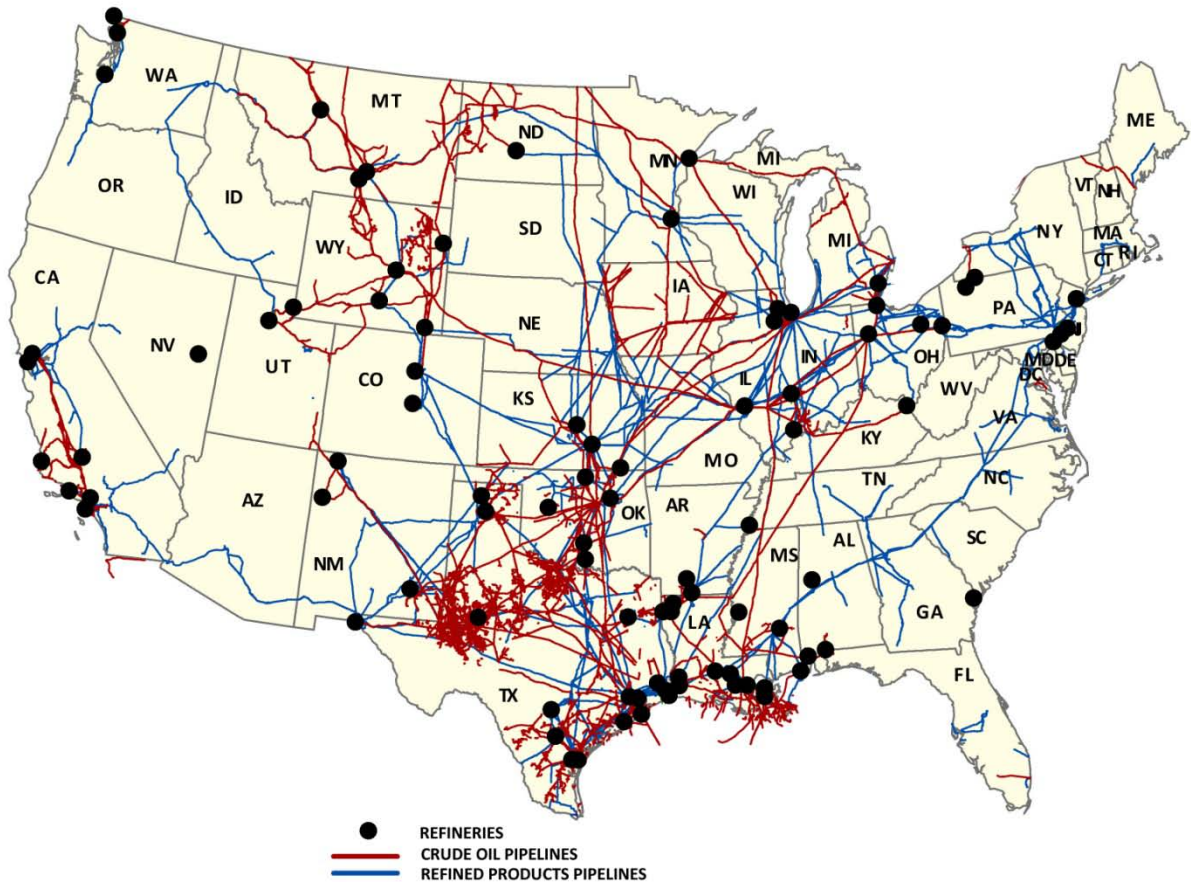
Among the major obstacles to unlocking the huge potential of the shale/tight plays in the Williston basin, the other shale/tight plays in the U.S., and the Canadian unconventional oils, is the lack of an adequate infrastructure to transport and refine oil, and sclerotic rules governing the overall U.S. oil domestic movements.

The U.S. champions free trade and free access to global oil for any country, but oil cannot move freely throughout the United States, or be exported from the country.

This striking paradox derives from several facts.

First, the U.S. crude oil market essentially consists of three different markets: the East market (PADD 1), the Mid-Continent markets (PADD 2 and 3) to the Gulf Area (PADD 4), and the West Coast market (PADD 5). These three markets are virtually disconnected: in particular, there are no East-West crude pipelines, and the Gulf region cannot supply crude oil to the East, which is not connected westward to the northern region of the U.S. and western Canada (as shown in Figure 5).⁴⁷

Figure 5: U.S. oil pipeline and refineries network



Consequently, the oil production of Western Canada and North Dakota relies on the same transportation system, stretching along a north-south corridor from Canada to the U.S. Gulf Coast, with a critical point at Cushing, Oklahoma, the most important oil-trading hub in the U.S. and the largest oil storage location in the world. That corridor is already inadequate to carry the growing supply of Canadian unconventional oils and North Dakota shale oil, but Montana and other states also rely on the same corridor. That is why part of the Bakken oil production moves by rail and truck, an inefficient and expensive way to move the oil.

In view of President Obama's speech in Cushing in March 2012 supporting additional oil pipelines, it is probable that the situation could change drastically, particularly after the Presidential elections of November 2012.

At least three substantial projects are scheduled to be completed by 2015. Enbridge and Enterprise Products Partners will more than double the capacity of the Seaway pipeline from Cushing to the Gulf Coast, adding 850,000 bd of new transportation capacity by mid-2014.

Simultaneously, the southern portion of TransCanada's Keystone XL project, which faced a strong environmental challenge, will add 700,000 bd of new capacity from Cushing to the Gulf Coast by the end of 2013. Finally, Enbridge's Flanagan South pipeline project from Flanagan, Illinois to Cushing may direct another 585,000 bd to the Oklahoma hub, offering North Dakota's Bakken and western Canadian oil producers an additional option to deliver their crudes to U.S. refineries.⁴⁸

However, even if all those pipelines start running before 2015, they could not meet the increasing takeaway needs of the combined, additional oil supply coming from western Canada and North Dakota. Additional lines will be required, unless part of the new Canadian output can take other routes, both in the U.S. and abroad. This would require Canada to build new pipelines as well.

Another serious problem overshadows U.S. shale and tight oil production. Regardless of the source of supply, most future shale-oil production will consist of light and sweet oil, the benchmark for which in the U.S. is WTI. This phenomenon presents a considerable challenge for the U.S. refineries along the central corridor to the Gulf Coast.

Most of them have reached a high level of complexity over the years through massive investments to increase their ability to process heavy-sour crudes, the majority of the U.S. oil imports.⁴⁹ For those refineries, switching to light oil will involve a decrease in economic margins and technical problems, unless the price of light oil falls until it can compete with heavy oil. Insufficient pipeline capacity, coupled with the refining issue, explains why from 2011 on, U.S. light oil traded at a strong discount compared to Brent, a similar crude (in terms of density and sulfur content) that is the most important international oil benchmark.

Theoretically, the possibility of exporting U.S. crude oil could address these questions, but U.S. laws ban oil exports for the sake of national security, except for modest volumes, which must be specifically authorized by federal authorities. Adding to the sclerosis, the Jones Act (passed in 1920) mandates that "any intra-U.S. shipping by water be done using vessels under US flag, built in the US, and manned primarily by U.S. crews."⁵⁰ Because of the Jones Act, it is expensive to move oil from any American port to another port in the U.S. by water, because shipping vessels are relatively small and their operating costs are high.

In addition to the problem of shale/tight oil transportation and refining, there is the difficulty of what to do in the near future with the trillion cubic feet of natural gas associated with shale/tight oil production. The natural gas price collapse of early 2012 led many companies to stop their intensive drilling activity in the shale gas arena, but they did not stop producing wells supplying methane to an already oversupplied market. The natural gas production associated with shale/tight oil plays, thus, could prolong the market apathy, complicating the overall economics of shale/tight oil production and even the feasibility of fully deploying its potential.

There is no silver bullet, nor a single best solution for this problem. Furthermore, there is no guarantee that the current U.S. natural gas market anemia is a long-term phenomenon, or that an unexpected increase in demand could not occur a few years from now.

To be sure, a prolonged bearish natural gas market could kill or severely hurt the renewable industry and its prospects for growth, divert investments from oil gas development, and limit the development of shale/tight oil. There are now supporters of gas exports through gas liquefaction, gas-to-liquid (GtL) projects, the development of a compressed natural gas (CNG) industry, and coal displacement through natural gas in power generation—each striving to demonstrate the appeal of its own solution.

Over this decade, another problem affecting the production of all shale/tight oil plays in the United States will be the inevitable rising costs of services, rigs, labor, and pipelines, caused by the inflationary pressure from the frenetic activity throughout the shale/tight oil and gas sector.

However, the advancing knowledge of shale oil development and the gradual expansion of the infrastructure necessary to each shale play should balance the rising costs, and eventually drive them down.

9. SHALE AND TIGHT OIL & GAS VERSUS THE ENVIRONMENT

As with shale gas, the major environmental concerns about shale oil are the consequences of hydraulic fracturing, which is thought to contribute to water and land contamination, natural gas infiltration into fresh water aquifers, poisoning of the subsoil through intensive use of chemicals during the fracking stages, and even minor earthquakes in some areas. These claims demand some explanation, for which I will turn to the growing body of data concerning the development of shale gas, which is similar to that of shale oil in terms of features and needs.

The pollution of water tables is a controversial subject. In general, shale gas deposits lie at depths greater than 3,000-4,000 feet, while freshwater aquifers are usually at depths of a few hundred feet (as shown in Table 4).

Table 4: Distance between major shale gas plays and freshwater aquifers in the U.S.

<i>Shale play</i>	<i>Depth to Aquifer (feet)</i>	<i>Depth to Shale (feet)</i>
Barnett	1,200	6,500-8,500
Fayetteville	500	1,000-7,000

Marcellus	850	4,000-8,500
Woodford	400	6,000-11,000
Haynesville	400	10,500-13,500

(Source: MIT)⁵¹

The thick strata of impermeable rock separating the water tables from the shale gas deposits should ensure absolute separation of one from the other, for which reason fracking alone should not affect the water tables. The fact remains that poorly sealed wells or wells lacking adequate steel jackets could allow dangerous contamination.

Cement sealing and steel jacketing of wells is standard practice in the oil industry. Above all, they prevent the walls of a well from gradually crumbling as the drilling continues, which would cause the well itself to collapse. Nevertheless, it is reasonable to expect that during early development of shale gas some of the many small firms working on this new frontier may have used quick and cheap methods, causing problems that in general practice should not have happened.

The separation between the water tables and the hydrocarbon deposits should also keep methane from spreading to water tables and wells. However, methane has been discovered in a limited number of water wells near shale gas extraction sites. In 2009, a water well in Dimock, Pennsylvania exploded because of the high concentration of methane.

According to the oil industry, the presence of methane in many water wells in areas where shale gas is being extracted has nothing to do with the drilling, but is a natural occurrence that predates the extraction operations. In May of 2011, the National Academy of Sciences published an independent study conducted by some American universities. The study demonstrated that the infiltration of methane in water wells near extraction activities was 17 times more common than in wells far from those areas.⁵²

The results of that study are still controversial. For example, a MIT research study recorded only 20 cases of groundwater contamination by natural gas or drilling fluids between 2005 and 2009, among thousands of wells drilled.⁵³ The MIT research did not encompass the whole spectrum of drilled wells and reported accidents, but it did provide a reliable, high-level approximation of the low incidence of groundwater contamination as a function of overall drilling activity. Once again, this does not mean that a problem does not exist, but only that it is extremely rare and that it can be managed effectively, if best practices are adopted in the drilling process and adequate controls are enforced.

The consumption of water required by fracking is certainly a problem, but a much smaller one than is generally feared. A shale well requires between four and five million gallons of water (15 to 19 million liters). Even when the drilling activity is frenetic, these volumes do not affect the

availability of water in the concerned areas, except for states where water availability is already a problem. Extensive data from shale gas operations show that “shale development water usage represents less than 1 percent of total water usage in the affected areas,” public supply and irrigation being the major sources of water consumption.⁵⁴ Moreover, the “water intensity of shale gas development, at around 1 gallon of water for every MBtu of energy produced, is low compared with many other energy sources.”⁵⁵

In any case, the solution to this problem is to minimize the use of water, a challenge that the industry is already coping with, searching for technological solutions that go from the recycle of wastewater from fracking operations to the use of high-pressure propane in place of water to fracturing wells, and the use of directional solvents. These solutions and others are in the experimentation stages and are still quite expensive, but they are necessary to cope also with another problem concerning fracking and water: what to do of contaminated water coming up from drilling operations.

Traditionally, any kind of wastewater (not only that resulting from oil and gas extraction) has been re-injected in specific wells and “buried” underground. In the future, however, this common practice will become less and less sustainable.

The chemicals used in the hydraulic fracturing process also threaten the potential of shale oil and gas. Polymeric chemicals are already used in various parts of the world for boosting oil recovery rates, and that application has never raised particular problems. As noted, more than one million fracking operations have been implemented in the United States alone, without evidence of contamination. The industry has tried to minimize the impact of chemicals in fracking, claiming they are not dangerous and that they correspond only to 0.5 percent by weight of the water injected into the wells. In any case, that claim is not very useful, because the volume is significant, on average more than 100,000 kg of chemicals per well.

In order to dispel any doubt and facilitate careful monitoring, the full disclosure of chemicals used in fracking should be mandatory, and the chemical and service companies providing those chemicals should not be permitted to invoke trade secret exemptions. Several states, including Texas, Arkansas, Pennsylvania, Colorado, Montana, and Michigan, already have regulations requiring the full disclosure of fracking fluid chemicals.

The possibility that fracking operations may produce earthquakes cannot be excluded, albeit remote and confined to particular kind of reservoirs.

So far, the only case of earthquakes linked to fracking was reported in Ohio, where in 2011 ten small earthquakes hit the seismologically sound state, culminating in an eleventh, record-breaking 4.0 magnitude quake on December 31, 2011, that rattled the residents of Youngstown. The Ohio Department of Natural Resources, which oversees the oil and gas industry, reported that it had

found "geological evidence" suggesting that high-pressure fluid from a well near an underground fault caused the earthquakes in Youngstown.⁵⁶

The Ohio earthquakes were all related to oil and gas activity, but to the disposal injection wells used for storing the used fluid from hydraulic fracturing. These wells go deep underground and can hold waste fluids from hundreds of fracking wells.

Ohio has nearly 200 deep wells in 41 counties, 177 of which are used primarily for oil and gas waste disposal. Since 1983, more than 202 million barrels of oilfield fluids have been disposed of in Ohio, more than half of that from out-of-state.⁵⁷

In the scientific community, it is generally recognized that injecting fluids into the ground may cause minor earthquakes. This because the fluids can hit a fault that is stuck because of friction. When the fluids arrive, the fault may slip and cause small movements and even quakes. Still, fracking to extract oil and gas is not the same as fracking to dispose of wastewater and fluids.

Oil and gas fracking must avoid allowing fluids to move freely underground and cause a fault to slip, because this could jeopardize the recovery of oil and gas or cause the well to collapse. On the other hand, fluid waste disposal does not require such attention.

Regardless, this issue demands considerable attention. The science fundamentals of the interaction between seismic activity and hydraulic fracturing are not very well understood yet. As long as this knowledge-gap exists, fracking activities should be banned in seismic active areas.

In sum, although the negative aspects of hydraulic fracturing may induce fear, and if there will always be a small level of risk, historical evidence and data suggest that the risks are confined to a few cases and even those may be minimized by using the best practices that serious companies apply.

Unfortunately, so far there has been a lack of a collective effort by industry to cope with these problems. This could be the result of the extreme fragmentation and small size of many operators working on shale, as well as the start-up phenomenon. In other words, the probability of errors is higher during the embryonic stages of development of a new field of activity, when a few standard practices exist and oftentimes problems are solved through a process of trial and error. Over time, oil industry has always made it better.

However, if such a collective effort by the industry does not materialize, that could create much more onerous regulation in the near future that could also affect the actual U.S. shale oil production.

Studying this subject led me to conclude that the conditions exist to avoid the tyranny of "or-or", the idea that preserving nature and the environment requires drastically limiting the development

of shale/tight. Instead, conditions favor a progressive “and-and” approach, supporting shale development while preserving nature and the environment, and improving the technologies that make it possible.

The U.S. Shale/Tight oil revolution might represent a real “game-changer” for the United States in a relatively short period of time, and not because of achieving so-called “energy independence.”

Since the 1970s, this notion has been of great importance in the U.S. political debate. Yet oil self-sufficiency, or quasi self-sufficiency, may be important only in cases of major wars, when the disruption of sizeable foreign oil supplies could endanger the military effort or the country’s self-defense. In all other cases, one must never forget that the oil market is global and fungible, and a country cannot be insulated from what is happening in the rest of the world even if it self-sufficient in terms of its own oil consumption. For example, a fall in oil prices because of overproduction in the Middle East can influence the market for higher-cost U.S. or Western hemisphere oil, just as an oil price spike during a major crisis in the Middle East can affect oil prices in the U.S.

For these reasons, I do not think it would be wise for the U.S. to lessen its interest in the Middle East because of its newly found quasi self-sufficiency. After World War II, the U.S. was still substantially self-sufficient in terms of oil availability, yet it established long-lasting alliances with many Middle East States to prevent Soviet Russia from penetrating the region and leveraging its influence to distort the global oil market.

The same risk would occur in the future if hostile countries or political movements were to fill void left by the U.S. Moreover, other western hemisphere producers, such as Canada, Venezuela, and Brazil, may shift their exports towards international markets for commercial reasons, thus contradicting the notion of western-hemisphere oil self-sufficiency.

Is all this irrelevant to the U.S.? Would it be a sound policy for the U.S. to turn its back on Saudi Arabia, Iraq, and other important Middle Eastern oil producers because it somehow no longer requires their oil? I think not.

In any case, the truly important impact of the U.S. Shale/Tight Oil Revolution is of different nature. Specifically, it could reflect the following:

- An advantage for U.S. GDP, employment, and balance of trade. Given the relative infancy of the boom, there are no extensive research studies or analyses of its potential contribution to the overall performance of the U.S. economy by 2020. So far, the only estimate of the broader effects of the combined shale oil and gas revolution on the United States economy has been made by Citigroup, according to which “the cumulative impact

of new production and reduced consumption could increase real U.S. gross domestic product (GDP) by 2% to 3.3%, or by \$370 billion to \$624 billion, by 2020.” As to the labor market, Citigroup estimated “that as many as 3.6 million new jobs may be created on net by 2020. Some 600,000 jobs would be in the oil and gas extraction sector, another 1.1 million jobs in related industrial and manufacturing activity, and the remainder in ancillary job sectors.” Finally, the shale hydrocarbon revolution may substantially affect the U.S. current account deficit, which, “currently running at negative 3% of GDP, may be reduced by anywhere from 1.2% of GDP to 2.4% of GDP.”⁵⁸ In the absence of other estimates, these bold figures may illustrate the magnitude of the U.S. shale hydrocarbon revolution.

- A pillar of the overall “liquidity” of the future global oil market, helping to lower oil prices. Without U.S. shale oils, as well as other unconventional oils from Canada, Venezuela, and Brazil, the consumers of the world would continue to experience phases of tight supply and high prices, especially during geopolitical crises.
- A great opportunity to seize technological leadership not only in oil production methods, but also in new ways of making oil production more environmentally and climate friendly.

All of these elements reinforce the need for a comprehensive, win-win solution. However, a detailed manual of such a solution is not the purpose of this paper.

III. CONCLUSIONS

10. WHAT IS REALLY AHEAD?

Like most predictions of a commodity production patterns, the one in this paper is subject to a significant margin of error, depending on several variables that extend beyond those listed in the specific country-by-country analysis in Sections 3-4.

In particular, a new world-wide economic recession, a drastic change in Chinese consumption patterns, or a sudden solution to major political tensions affecting a major oil producer (such as Iran), could trigger a major decrease and even a collapse of the price of oil. By collapse, I mean a fall below \$50 per barrel for one year.

The oil market is already adequately supplied with spare capacity of around 4 mbd. This should be able to absorb a major disruption even from a major oil producer like Iran. Furthermore, global production capacity is regularly surpassing demand, in spite of the political and infrastructural problems of several producing countries. In fact, the mere dynamics of supply, demand, and spare capacity cannot explain the high level of oil prices today.

At more than \$100 per barrel, the international benchmark crude, Brent, is \$20 to \$25 above the marginal cost of oil production. Only geopolitical factors (above all, a major crisis related to Iran) and a persistent belief that oil is about to become a scarce commodity can explain the departure of oil prices from economic fundamentals of demand and supply.

When I completed the first version of this paper (March 2012), oil prices were even higher, then the forces I was describing started pushing them down. Yet at this writing, most people remain convinced that fundamentals are still in favor of rapid recovery of oil prices. My feeling is the opposite.

The timing of a hypothetical downturn or collapse is crucial to understanding its duration and its impact on the global oil market. Most of the projects I studied are still being developed, with higher initial costs to adopt new technologies, build infrastructure, and overcome the learning curve. The downturn or collapse of the oil market would have a significant impact, particularly if it occurred before 2015, when most of these projects have yet to advance. However, the duration and effect of such a collapse would probably be of short duration.

A sudden dip below \$50 would not necessarily suspend the development of many projects worldwide, but would only slow their execution. The exception would be those projects that hold the highest marginal costs, such as some Canadian tar sands projects, Venezuelan extra-heavy oils, Brazilian pre-salt formations, as well as those projects that can be stopped immediately, such

as U.S. shale/tight oil ones those of OPEC producers, whose execution depends on the will of governments.

Such a response from oil companies and governments would soon curtail new production, leaving the world market vulnerable to sudden disruptions by geopolitical factors or major accidents once again. Furthermore, market instability would likely coincide with a rebound of oil demand, driven by lower prices. Market forces should then realign prices with the higher marginal production costs in less than two years.

Conversely, if an oil price collapse were to occur after 2015, a prolonged phase of overproduction could take place, because production capacity would have already accumulated and production costs would have decreased as expected. This is what happened to shale gas production in the United States between 2011 and 2012. In this case, market recovery will depend critically on the strength of the world economy as well as geopolitical factors affecting the steady flow of oil on the global market.

Finally, the worst scenario would involve a collapse of China, which would make any current forecast about the future of the oil market (and the world economy) useless. Being China the current engine of the world economy and of oil price consumption growth, its collapse would leave the oil price fall without a floor.

The opposite may also be true, although it appears much less probable. A sudden, robust recovery of the world economy could hurt the equilibrium of oil demand and supply, particularly if accompanied by geopolitical tensions, pushing oil prices up once again. This scenario, however, would support an even stronger rush to develop new oil reserves and production.

I have no particular preference for any of these scenarios, or any combination of them, although I think that the probability of a significant fall of oil prices is higher than all other scenarios.

Whatever the belief, the most important messages of this paper are as follows:

- Oil is not in short supply. From a purely physical point of view, there are huge volumes of conventional and unconventional oils still to be developed, with no “peak-oil” in sight. The full deployment of the world’s oil potential depends only on price, technology, and political factors. More than 80 percent of the additional production under development globally appears to be profitable with a price of oil higher than \$70 per barrel.
- Other things being equal, any significant setback to additional production in Iraq, the United States, and Canada would have a negative impact on the global oil market, given their potential for new production by the year 2020. However, also a significant setback of traditional big producers such as Saudi Arabia or Russia could have the same effect,

proving once again that the oil market is global and none of its pieces (e.g., countries) can be insulated from the other.

- The shale/tight oil boom in the United States is not a temporary bubble, but the most important revolution in the oil sector in decades. It will probably trigger worldwide emulation, although the U.S. boom is difficult to be replicated given the unique features of the U.S. oil (and gas) arena. Whatever the timing, emulation over the next decades might bear surprising results, given the fact that most shale/tight oil resources in the world are still unknown and untapped. China appears to be the first country to follow the U.S. example. Moreover, the extension of horizontal drilling and hydraulic fracturing combined to conventional oil fields might dramatically increase world's oil production and revive mature, declining oilfields.
- In the aggregate, conventional oil production is also growing throughout the world, although some areas (the North Sea, face an apparently irreversible decline of the production capacity. In most traditional producing countries, old oilfields go through a production revival thanks to better techniques and knowledge, or advanced exploration and production technologies, so far used only in the U.S. and in the North Sea. Huge parts of the world are still relatively unexplored for conventional oil (for example, the Arctic Sea or most of sub-Saharan Africa).
- The age of "cheap oil" is probably behind us, but it is still uncertain what the future level of oil prices might be. Technology may turn today's expensive oil into tomorrow's cheap oil.
- The oil market will remain highly volatile until 2015 and prone to extreme movements in opposite directions, thus representing a major challenge for investors, in spite of its short and long term opportunities. After 2015, however, most of the projects considered in this paper will advance significantly and contribute to a strong build-up of the world's production capacity. This could provoke a major phenomenon of overproduction and lead to a significant, stable dip of oil prices, unless oil demand were to grow at a sustained yearly rate of at least 1.6 percent for the entire decade.
- A revolution in environmental and curb-emissions technologies is required to sustain the development of most unconventional oils, along with a strong enforcement of already existing standards, rather than massive over-regulation. Without such a revolution, a continuous dispute between the industry and environmental groups will force government to delay the development of new projects.

- If the revolution I have described in this paper achieves its maximum potential, it will have major geopolitical consequences.
- In particular, it will make Asia the reference market for the bulk of Middle Eastern oil, and China a new protagonist in the political affairs in the region.
- At the same time, the Western Hemisphere could return to a pre-World war II status of oil self-sufficiency, and the United States could dramatically reduce its oil import needs. However, this will neither insulate the country from the rest of the global oil market, nor diminish the critical importance of the Middle East to its foreign policy.
- The unconventional oil revolution in the U.S. and the Western Hemisphere must not obscure the fact that through 2020 and beyond, more than 50 percent of the global oil supply will continue to come from a geographic arc stretching from Russia to the Persian Gulf. Every major event concerning this geographic arc will be critical to the overall stability of the global oil market.
- It's also true, however, then over the next decades, the growing role of unconventional oils will make the Western hemisphere the new center of gravity of oil exploration and production.

¹ The whole Bakken formation also runs beneath Montana, part of South Dakota, and Canada.

² USGS (United States Geological Survey). 2000. *World Petroleum Assessment, 2000*. <http://pubs.usgs.gov/dds/dds-060/>

³ *Russia Producers Take Action on Decline Rate*. In: Petroleum Intelligence Weekly, March 22, 2012.

⁴ National Petroleum Council, *Hard Truths: Facing the Hard Truths about Energy*, July 2007.

⁵ Klett, T.R., Attanasi, E.D., Charpentier, R.R., Cook, T.A., Freeman, P.A., Gautier, D.L., Le, P.A., Ryder, R.T., Schenk, C.J., Tennyson, M.E., and Verma, M.K., 2011, New U.S. Geological Survey Method for the Assessment of Reserve Growth: U.S. Geological Survey Scientific Investigations Report 2011-5163.

⁶ Klett, Thomas, and James Schmoker. *Reserve Growth of the World's Giant Oil Fields*. In: *AAPG Memoir 78*. Tulsa: The American Association of Petroleum Geologists), 2003, p. 107–122.

⁷ Klett and Schmoker, 2003.

⁸ Adelman, Morris. *The Genie Out of the Bottle*. Cambridge, MA: The MIT Press, 1995, p.15.

⁹ Maugeri, Leonardo. Squeezing More Oil From the Ground. In: *Scientific American*, October 2009, p. 56-63.

¹⁰ Maugeri, Leonardo. Two Cheers for Expensive Oil. In: *Foreign Affairs*, March-April 2006, Vol. 2, Nr. 85, p. 149-161.

¹¹ USGS (United States Geological Survey). 2003. *Heavy oil and natural bitumen—strategic petroleum resources*, ed. Richard F. Meyer and Emil D. Attanasi. Reston, VA: United States Geological Survey. <http://pubs.usgs.gov/fs/fs070-03/fs070-03.html>

-
- ¹² WEC (World Energy Council). 2007. *Survey of energy resources 2007*. http://www.worldenergy.org/publications/survey_of_energy_resources_2007/default.asp
- ¹³ www.argusmedia.com/News/Article?id=778232
- ¹⁴ See: www.energyintel.com
- ¹⁵ In 1996, the Venezuelan national oil company PDVSA launched a ten-year development plan to raise the country's production capacity to more than 6 mbd, from 3.3 mbd. Maugeri, Leonardo. *The Age of Oil: The Mythology, History, and Future of the World's Most Controversial Resource*. Westport (CT): Praeger, 2006, p. 171.
- ¹⁶ For a review of the mistakes in forecasting oil demand, see: Maugeri, Leonardo. Understanding Oil Price Behaviour through the Anatomy of a Crisis. In: *The Review of Environmental Economics and Policy*, Summer 2009.
- ¹⁷ Russia Producers Take Action on Decline Rate. In: *Petroleum Intelligence Weekly*, March 22, 2012.
- ¹⁸ Ibid.
- ¹⁹ For a comprehensive view of oil shale and its potential in the U.S. see: U.S. National Petroleum Council (NPC), Oil Shale, Topic Paper 27, July 18, 2007. www.npc.org/Study_Topic_Papers/27-TTG-Oil-Shales.pdf
- ²⁰ National Petroleum Council (NPC). *Prudent Development: Realizing the Potential of North America's Abundant Natural Gas and Oil Resources*. Washington, DC: NPC, 2011, p.21.
- ²¹ The shale gas saga began with a small Texas company, Mitchell Energy. Other companies like Mitchell were the protagonists of the U.S. shale gas revolution.
- ²² See: www.eia.gov/analysis/studies/usshalegas/
- ²³ The Bakken production in Montana jumped from virtually nothing in 2000 to nearly 50,000 boe/d by 2005.
- ²⁴ Official data by the government of North Dakota. See: <https://www.dmr.nd.gov/oilgas/stats/historicaloilprodstats.pdf>
- ²⁵ The Energy and Environmental Research Center at the University of North Dakota got a copy of the Leigh Price Study, entitled "Origins and Characteristics of the Basin-Centered Continuous Reservoir Unconventional Oil-Resource Base of the Bakken Source System, Williston Basin". See: www.undeerc.org/Price
- ²⁶ Price, p. 22 and p. 235.
- ²⁷ Oil Daily, February 27, 2012.
- ²⁸ Maugeri, Leonardo. *The Age of Oil*, p. 223.
- ²⁹ Price, p. 235.
- ³⁰ See Continental Resources technical papers at: www.contres.com/operations/technical-papers
- ³¹ Schmoker, J.W. and Hester, T.C., 1983, Organic carbon in the Bakken Formation, United States portion of Williston basin: *American Association of Petroleum Geologists Bulletin*, v. 67, no. 12, p. 2165-2174.
- ³² Meissner, F.F. and Banks, R.B., 2000, Computer simulation of hydrocarbon generation, migration, and accumulation under hydrodynamic conditions – examples from the Williston and San Juan Basins, USA: *American Association of Petroleum Geologists Search and Discovery Article #40179*.
- ³³ Flannery J. and Kraus, J, 2006, Integrated analysis of the Bakken petroleum system, U.S. Williston basin: *American Association of Petroleum Geologists Search and Discovery Article #10105*.
- ³⁴ Bohrer, M., Fried, S, Helms, L., Hicks, B., Juenker, B., McCusker, D., Anderson, F., LeFever, J.,

Murphy, E., and Nordeng, S., 2008, Bakken Formation Resource Study Project: North Dakota Department of Mineral Resources Report, p.23.

³⁵ Se USGS at: http://pubs.usgs.gov/fs/2008/3021/pdf/FS08-3021_508.pdf

³⁶ The data are elaborated from Baker Hughes rig count. See: www.bakerhughes.com

³⁷ Data collected by the author from different sources.

³⁸ Sattler, Casey. Shale Gas Technologies Unlock Oil Bounty in Bakken, Permian. In : *Natural Gas Week*, December 19, 2011.

³⁹ Sattler (2011).

⁴⁰ Data gathered by the author.

⁴¹ Data gathered by the author.

⁴² www.eaglefordshale.com/companies/eog-resources/

⁴³ Data gathered by the author from different sources.

⁴⁴ Deutsche Bank. The Future of US Oil. Deutsche Bank, Markets Research, 28 February 2012.

⁴⁵ www.uticashalenews.com/

⁴⁶ www.ogfj.com/articles/2011/11/anadarko-estimates.html

⁴⁷ An excellent and up-to-date analysis of the problems of the U.S. oil transportation system can be found in Deutsche Bank (2012).

⁴⁸ See: New Pipelines Should End Cushing Crude Glut. In: *Oil Daily*, March 28, 2012.

⁴⁹ In particular, as reported by Petroleum Intelligence Weekly, “Five US Midwest and Gulf Coast refineries - WRB's Wood River, Illinois, plant; Marathon's facility in Detroit; BP's Whiting, Indiana, plant; and the Total and Motiva facilities at Port Arthur, Texas - have been undergoing multibillion-dollar coking upgrades that will allow them to process higher volumes of heavy crude, particularly so-called ‘dilbit,’ or diluent and bitumen blend, from Canada's tar sands. These five projects alone are set to back out about 420,000 barrels per day of light crude demand from the US market by 2013.” See: US Facing a Light, Sweet Crude Glut. In: *Petroleum Intelligence Weekly*, April 16, 2012.

⁵⁰ Deutsche Bank (2012), p.12

⁵¹ MIT. *The Future of Natural Gas*. Cambridge, MA: MIT Energy Initiative, 2011, p. 40.

⁵² Osborn, Stephen, Aven Vengosh, Nathaniel Warner, and Robert Jackson: “Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing” in *Proceedings of the National Academy of Sciences*, PNAS 2011 108 (20) 8172-8176; <http://www.pnas.org/content/108/20/8172.full>

⁵³ MIT. 2011, p. 39.

⁵⁴ MIT., 2011, p. 42-43.

⁵⁵ MIT. 2011, p. 44.

⁵⁶ <http://www.scientificamerican.com/article.cfm?id=ohio-earthquake-likely-caused-by-fracking>

⁵⁷ Ibid.

⁵⁸ Morse, Ed. Move Over, OPEC—Here We Come. In: *The Wall Street Journal*, March 20, 2012.

APPENDIX A

A NOTE ON METHODOLOGY

The most common critique of this paper throughout the review process has been the subjective nature of my evaluations about the data and risk-factors affecting future oil production and the weight I assigned to those factors in the paper. The problem, as described by one of the reviewers, is *“to determine how much of this work is data collection coupled with reproducible analysis, and how much is an application of an educated thumb on the scales that might be different for different people.”*

I was aware of this issue as I considered my argument and the structure of the paper, as it is a typical question for those working in the oil industry. Having a field-by-field database, it is relatively simple to decipher the potential production of each oilfield, given the extensive flow of data released periodically by companies and countries.

Usually, once a company (or country) determines the producible reserves of a field (after having assessed its proven reserves, its initial rate of recoverability, and its costs) and begins to invest in its development, it is rarely wrong. Errors are common in exploration activity, but once a production plan is defined, technical errors concerning the producible reserves of the field are rare. More often, over time a field produces much more than initially planned, as I explained in Section 1 of the paper. Nonetheless, actual production could turn out to be lower than predicted due to governmental decisions made by the host country (such as new fiscal, environmental, or export mandates, revision of contractual schemes, etc.), lack of specific authorization, and political instability.

As discussed in Section 2, the oil sector has no precise methodology by which to adjust reserve and production forecasts considering all risk factors, and there is no other way to determine the significance of these risk factors than through subjective experience and judgment.

The Iraqi example illustrates the methodology I used in this paper and the common problems I (and other analysts) encountered while assessing risk-factors. As with all other countries, I analyzed the data of the respective oilfields, beginning with those that have been approved for re-development by international oil companies. As summarized in Table 1, Section 3 (reproduced below), the data concerning Iraqi oilfields' current production and future production targeted by international oil companies are explicitly outlined.

Table 1: Peak planned production of already approved Iraqi oil contracts (*excluding the Kurdish Regional Government*)

Field	Foreign Companies (Share)	Production Target (initial production)
Rumaila	BP (38%) CNPC (37%)	2,850,000 (1,100,000)
West Qurna 1	Exxon (60%) Shell (15%)	2,350,000 (270,000)
Zubair	Eni (32.8) Occidental (23.5%) Kogas (18.75)	1,200,000 (200,000)
Missan fields**	CNOOC (63.75%) TPAO (11.25%)	450,000 (100,000)
Majnoon	Shell (45%) Petronas (18.75%)	1,800,000 (50,000)
West Qurna 2	Lukoil (56.25%) Statoil (18.75)	1,800,000 (120,000)
Halfaya	CNPC (37.50%) Petronas (18.75%) Total (18.75%)	535,000 (70,000)
Gharaf	Petronas (45%) Japex (30%)	230,000 (35,000)
Badra	Gazprom (30%) Kogas (22.5%) Petronas (15.5%) TPAO (7.5%)	170,000 (15,000)
Qaiyarah	Sonangol (75%)	120,000 (20,000)
Najmah	Sonangol (75%)	110,000 (20,000)
Total Production Targets * (Current capacity)*		11,615,000 (2,000,000)
Iraq Total Current Capacity***		2,800,000

**Includes the Fakka, Buzurgan and Abu Ghirab fields*

***End of 2011. Includes other fields that still await re-development, such as supergiant Kirkuk, East Baghdad, and Nasiryiah.*

There is no dispute about the technical sustainability of the targets for future production set by international oil companies and agreed upon by the Iraqi government, as all experts and industry operators recognize that the exploration and production methods used in Iraq under Saddam Hussein did not include many modern technologies (such as deep-drilling, horizontal drilling, correct re-injection of water and natural gas). As I pointed out in Section 3, the fundamental problems hindering the realization of Iraqi oil potential concern political instability, governmental decisions, and the infrastructure development such as pipelines and export terminals. The only direct way to address the impact of these problems is to acknowledge there are a range of

subjective judgments about how likely these obstacles are to arise and how severe they will be when they do. This subjective assessment is the basis of the discount-factor (percentage) I choose to account for those risks. I am transparent about the risk factor I select, so that others may decide if such a subjective evaluation is too optimistic, too pessimistic, or wholly unrealistic.

In other cases, factors besides political decisions and instability play a role that is difficult to quantify.

In the case of Angola, for example, the data on several oilfields' development were accurately delineated. Coupled with a relatively stable political situation, one might anticipate that most projects will be finished on-schedule. However, I didn't trust the estimated peak-production schedule estimated by companies and experts, due to the technical and environmental difficulties that have emerged so far in developing Angola's ultra-deep offshore fields; it is this oil that represents the bulk of Angola's future new oil production. As a result, I advanced the peak-production schedule of those projects, as shown in Table 5.

Table 5: Angola's oilfields under development

<i>Oilfields</i>	<i>Estimated Peak production</i>	<i>Liquid production</i>	<i>Operator</i>
Plutao, Saturna, Venus Marte (PSVM) water	2015	150,000	BP
Platino, Chumbo, Cesio	2015	75,000	BP
Palas, Ceres, Juno, Astrea, Hebe, Urano, Titania	2016	150,000	BP
Terra Miranda, Cordelia, Portia	2016	150,000	BP
Lucapa	2016	100,000	Chevron
Mafumeria Sul	2017	95,000	Chevron
Negage	2016	75,000	Chevron
LNG various fields	2015	63,000	Chevron
Cabaca Norte	2016	40,000	Eni
Kizomba D satellites	2016	125,000	ExxonMobil
Cravo-Lirio-Orquidea-Violeta (CLOV)	2014	160,000	Total
Pazflor-Perpetua, Zinia, Hortensia, Acacia	2014	220,000	Total
Kaombo-Gindungo, Canela, Mostarda, Salsa, Louro	2014	120,000	Total

Eventually, I decreased the total production from these fields, not because I was uncertain of their actual potential, but because the technical obstacles and growing costs of operating in ultra-deep offshore are turning to be limiting factors that are preventing oil companies to meet their very aggressive development schedules.

Past performance and recent history also influenced my evaluation of many other projects in different countries. This is the case of the largest conventional oilfield in the world, Saudi al-Ghawar. Al-Ghawar produces about 5 mbd of oil today, and it represents around 40 percent of the current Saudi oil production capacity. It has produced such volumes of oil for many years, but since the early 2000s several experts have expressed doubts about the sustainability of its production.

These doubts stem from the relatively high *water cut* in al-Ghawar (the portion of water produced with oil). The water cut typically increases in all oilfields as they get older, after several years or decades of production and particularly after water injection techniques have been applied to sustain their internal pressure (and thus their production capacity). Thus, a high level of water cut is associated with the declining stage of an oilfield.

In 2000, al-Ghawar's water cut reached 37 percent, meaning that for every 63 barrels of oil produced, 37 barrels of water were also produced. Since then, however, Aramco has succeeded in lowering it close to 25 percent using more sophisticated technologies. In addition, thanks to the introduction of both more precise exploration tools and innovative production technologies (such as "intelligent" and multilateral wells) Saudi Aramco has been able to discover new al-Ghawar satellites and to recover more oil from the field. In effect, al-Ghawar continues to produce about 5 mbd, and Saudi Aramco even stated that the field need not rely on enhanced oil recovery technologies to maintain its current production level until at least 2025. (In contrast, if the many skeptics about al-Ghawar were right, by now its production field would have already faced a steep decline). The record of Saudi Aramco and the analysis of the data I had then allowed me to confirm the slightly less than 5 mbd figure for al-Ghawar by 2020.

Some may assign serious risks within Saudi Arabia's oil sector and a high possibility of political instability, and therefore would revise my evaluation about its future oil production accordingly. However, the Saudi oil system is one of the most protected in the world, considering no major attack has ever been brought against it, and even the attempts to hit parts of it – such as in the 2006 raid against the biggest Saudi refinery – produced no result). Additionally, the Kingdom appears to be capable of coping with major accidents in a short period of time (thanks in part to the support of many countries, due to its key role for the global oil supply). In sum, a Saudi oil disruption would most likely be short-term (no longer than 6-12 months). It's also worth pointing out that since the 1980s, several analyses have suggested the possibility of impending political crises and even radical upturn of the Saudi regime – either because of the death of a King, or

because of the uprisings (particularly in the eastern region of the Kingdom), or because of a supposed chain-reaction phenomenon determined by international events (such as the Arab Spring). However, these dire analyses fell short of reality: the Kingdom has proved to be solid and capable to absorb challenges to its survival.

I was not so generous with all countries, however. In many cases, my evaluations were much more conservative than those released by companies, countries, and other experts. This is the case with regards to Iran and Kazakhstan, for example.

I was hesitant about Iran, not only due to the lack of technical details about the potential of several Iranian fields. I was also skeptical about the possibility that Iran can balance its steep oil depletion with new production, given its international isolation and confrontational policies, which results in a lack of funding and technological knowledge and tools. I also take seriously the continued risk of Iran provoking a major crisis. I therefore cut Iran's future production profile well below the general estimates of most other analysts. As a consequence, the adjusted new production I calculated is not enough to offset the depletion of the already producing Iranian fields, whose steep decline is a result of the lack of adequate technology and reservoir management skills.

With Kazakhstan, I was confident about the country's resource potential and the production targets set by the international oil companies operating in its oil and gas sector. However, I am not optimistic about the actualization of these targets, above all given the Kazakh government long-lasting record of making life harder and harder for oil companies, thus creating a political and business landscape that has become one of the trickiest to navigate in the oil world.

These few examples demonstrate how the analysis of future oil production is country-tailored (and sometimes, field-tailored) and inherently subjective. Perhaps it would be possible to develop a bottom-up model tailored around the specific features and risks of any country and its oilfields. But even in this case, we would still be making approximations based on subjective evaluations of imponderable risks.

Eventually, the analysis of the world's future oil production should be based on the sum of the results obtained by those country-tailored models. To my knowledge, this kind of comprehensive, oil-sector tailored tool does not exist today, otherwise I would have employed it here. Instead, I utilized my field-by-field database, several technical sources which allowed me to update and reconsider my data, and my own expertise and judgment. I tried to be as transparent as possible by indicating the discount-factors I used to assess each country-risk, and – above all – by clearly showing the evolution of each major producing country's production, from its current production capacity, additional unrestricted and adjusted production, its depletion and reserve growth, to what I considered its effective production capacity by 2020.

I am confident in the results of my analysis, despite the high margin of error that every analysis of this kind may face. Most of all, however, I am confident of the fundamental message that emerges from my analysis: however one may consider the impact of risk-factors, or however one may predict the actual evolution of the world's oil production, the resource base under development is huge, much higher than generally believed.

In November 2011, when I started writing this paper, my data and its analysis suggested that world's oil production capacity was about to increase rapidly. Today, it is continuing to grow in spite of the instability of the world economy and the weakness of oil demand. Unless a major international crisis disrupts a significant part of that growing oil production capacity, it is difficult to see what might restrain this mounting wave of new oil – at least in part – to reach the market by 2020.



Belfer Center for Science and International Affairs

Harvard Kennedy School

79 JFK Street

Cambridge, MA 02138

Fax: (617) 495-8963

Email: belfer_center@harvard.edu

Website: <http://belfercenter.org>

Copyright 2012 President and Fellows of Harvard College