Global Energy Markets in a Time of Political Change

The Aspen Institute

Energy and Environment Program

2011 Forum on Global Energy, Economy and Security

Bill White, Chair
Leonard L. Coburn, Rapporteur

The Aspen Institute

Global Energy Markets In A Time Of Political Change

2011 Forum on Global Energy, Economy and Security

Bill White, Chair

Leonard L. Coburn, Rapporteur

For additional copies of this report, please contact:

The Aspen Institute
Publications Office
109 Houghton Lab Lane
P.O. Box 222
Queenstown, MD 21658
Phone: (410) 820-5326
Fax: (410) 827-9174
E-mail: publications@aspeninstitute.org
Web: www.aspeninstitute.org/eee

For all other inquiries, please contact:

The Aspen Institute
Energy and Environment Program
One Dupont Circle, NW
Suite 700
Washington, DC 20036-1193
Phone: (202) 736-2907
Fax: (202) 467-0790

David Monsma
Executive Director

John A. Riggs
Senior Fellow

Timothy Olson
Project Manager

The Aspen Institute
One Dupont Circle, NW
Suite 700
Washington, DC 20036-1193

Published in the United States of America in 2011
By The Aspen Institute

Printed in the United States of America

11-022
ISBN: 0-89843-558-7

Table of Contents

Foreword

Energy issues remain central to North American and global economic and political discussions. Political changes in the U.S., inaction on climate change legislation, a slow economic recovery, fiscal problems in the U.S. and Europe, and developments in unconventional resources have influenced the near-term discussion but not the underlying challenges of energy supply and security.

To explore these and other issues, the Aspen Institute's seventh annual Forum on Global Energy, Economy and Security convened in Aspen from July 14 to 17, 2011. The goal was to share information and to encourage new, collaborative, cross-disciplinary and non-partisan thinking. Five half-day sessions were introduced by brief, expert presentations, but the majority of time was devoted to an informal and candid roundtable dialogue. To encourage candor, all discussions were off the record.

The dialogue was chaired by Bill White, former Deputy U.S. Energy Secretary and former mayor of Houston. His extensive experience in both the private and public sectors enabled him to frame the discussion and elicit contributions from diverse expert participants. The highly qualified speakers listed in the agenda provided a wealth of information and a variety of perspectives, contributing substantially to the richness of the dialogue.

The Institute acknowledges and thanks the following Forum sponsors for their financial support. Without their generosity and commitment to our work, the Forum could not have taken place.

ExxonMobil	ConocoPhillips
American Clean Skies Foundation	Jefferies & Co.
Aramco Services Co.	Schlumberger
Cheniere Energy	Toyota
Chesapeake Corporation	TransCanada
Chevron	Westport Innovations

On behalf of the Institute and the Forum participants, I also thank Leonard Coburn, who served as rapporteur. With a strong background in energy, he was able to identify the important threads from a wide-ranging discussion and weave them into this summary report.

Timothy Olson managed the administrative arrangements for the Forum with thoroughness and dedication. He was ably assisted by Nikki DeVignes. Their hard work was responsible for a pleasant and smoothly run meeting. Along with the participants, I am grateful for their support.

This report is issued under the auspices of the Aspen Institute, and neither the Forum speakers, participants, nor sponsors are responsible for its contents. Although it is an attempt to represent views expressed during the Forum, all views expressed were not unanimous and participants were not asked to agree to the wording.

John A. Riggs
Senior Fellow
Energy and Environment Program

Global Energy Markets in a Time of Political Change

Leonard L. Coburn
Rapporteur

Global Energy Markets in a Time of Political Change

A shift in relative energy consumption among regions and the development of new, unconventional supplies will be the most significant changes over the next twenty years. The dominant fuels in the world energy market until 2030 will continue to be hydrocarbons — oil, coal, and natural gas. Major shifts will occur, however, among the three fuels, among regions and in their supply. Globally, oil will continue to be the most widely used fuel as it supplies more than 90 percent of the energy for transportation. Coal, now the dominant fuel used for electric power generation, will lose ground to natural gas, a less carbon-intensive hydrocarbon. Natural gas will become the second largest overall supplier and well positioned to replace coal as the leading supplier for electric power. Developing countries will lead the way in overall energy growth, with Chinese and Indian energy demand growing fastest. Energy demand in developed countries will remain flat. For the United States, growth in gas shale and oil shale are likely to be "game changers," altering the supply picture dramatically.

Some new oil supplies will come from Iraq and Brazil. Both have substantial reserves, attract large new investments from the international oil companies (IOCs) in partnership with the respective national oil companies (NOCs), and are ramping up production for exports. Russia, today's largest oil producer, will struggle to sustain this success due to under-investment in its aging oil fields and lack of incentives to shift its production to newer, harder to develop fields.

Traditional suppliers in Latin America — Mexico and Venezuela — are experiencing production declines as internal policies undermine investment necessary to sustain production.

New energy supplies will also come from unconventional sources of both oil and gas being developed in North America. In the United States, oil and gas shale production using new technologies — horizontal drilling and hydraulic fracturing — will elicit increasingly large volumes of new supplies. In Canada, growth in oil sands production is changing the supply picture. Taken together, these developments are creating major new supplies just when many thought North American supplies had peaked and were diminishing. Investment is flowing into these unconventional resources at a phenomenal rate, undermining the notion that the world is running out of new supplies of energy. The development of these unconventional resources, however, involves potential environmental problems that must be resolved if the potential of the resources is to be realized.

The regional shift in energy consumption places a spot light on China and other developing countries. China, now the world's largest energy consumer, is making a massive effort to find investment opportunities internationally. Its oil companies are limited in their domestic investment options, forcing overseas investment. In 2010, China's foreign direct oil investments were larger than those of any other country. The foreign policy implications of China's more assertive foreign role may be significant, since its interests often conflict with those of other countries seeking similar international opportunities.

America's development of its gas and oil shale resources is changing its supply profile. The United States is now the world's largest natural gas producer and within the next five years may be in a position to export its gas, altering current world markets. With the wide disparity between oil and natural gas prices, the savvy investor is moving to oil shale development, using similar technology as in gas shale. While oil shale production is expensive, it is changing the trajectory of production in the United States — oil production has halted its long downward trend and is now increasing. While gas shale production has slowed somewhat in the last two years, it is still economic despite low natural gas prices.

Transportation still relies on oil, although vehicle manufacturers are accelerating their search for alternatives. Natural gas is a possibility as supplies are plentiful; however, impediments include developing infrastructure to support changes. Heavy duty vehicles may have the best prospects for using natural gas. Electricity is another promising alternative. Limited range may prevent significant market penetration until battery technology improves and consumers are satisfied the technology is reliable. Until that happens, hybrid electric vehicles may be a more attractive choice. The United States has proposed significant increases in fuel economy standards in the coming years. Further improvements by using ultra-light and ultra-strong carbon fiber materials may be attractive, but resistance to making the necessary large capital investments creates large hurdles. Biofuels may be able to penetrate fastest since existing infrastructure can be used; however, there are environmental and cost issues associated with its use. All transportation options are on the table.

The Outlook: Regional Shifts Leading Energy Growth

Global energy markets are experiencing regional and technological changes of historic proportions. While overall demand will grow by 35 percent through 2030 due to economic and population growth, it will shift even more to developing countries than in recent years. The energy consumption of developed countries will remain flat, while that of the developing world, led by China and India, will increase by 70 percent. Coal, natural gas and oil will continue to be the main sources of energy, meeting approximately 80 percent of global demand. Alternate sources will play an increasingly important role. New drilling technologies will continue to play an important role as gas and oil shales become increasingly important, while advances in renewable energy technologies will make wind, solar, biofuels and other energy sources more competitive.

Within the energy sector, transportation and electric power will be the major drivers of demand growth. Globally, transportation energy demand will increase by 40 percent in the next twenty years, second only to power generation. There will be 400 million more cars on the road, increasing the global auto fleet to 1.2 billion. Regional shifts will be stark. Automobile fuel demand will decline by twenty percent in North America and by one-third in Europe. The reductions are due to gains in fuel economy from improvements in internal combustion engines and the increasing penetration of hybrids — to 25 percent of new car sales. The Asia-Pacific region will offset this decline, with overall transportation fuel demand doubling by 2030 while auto fuel demand grows by 80 percent. China will lead all markets with a total of about 200 million vehicles. Globally, heavy-duty vehicle fuel demand (trucks and buses) will increase by 30 percent in North American and Europe and more than 100 percent in the Asia-Pacific region.

Electric power generation will increase globally by more than 80 percent by 2030. Growth in emerging economies will exceed 150 percent while developed economies will increase by about 25 percent. China will account for 35 percent of global electricity growth. Due to their lower cost, coal and natural gas dominate fuel choice today, with about two fifths of today's power coming from coal and one fifth from natural gas. Fuel costs will shift as limits are imposed on greenhouse gas (GHG) emissions.

Policies on climate change could have a major influence on fuel choice. Assuming a price of $30 per ton of CO_2 is adopted in OECD countries, natural gas for power generation will become cheaper than coal. Coal's share of the global generation market will drop to 30 percent, while nuclear and wind will become increasingly competitive. Globally, demand for natural gas for power generation will grow by 85 percent. In North America, natural gas use will nearly double. Solar power and coal- and gas-fired plants with carbon capture and storage (CCS) technologies still may not be competitive even at $60 per ton of CO_2. Use of coal will decrease in North America and Europe, but in the Asia-Pacific region coal demand for electricity will grow 85 percent. But other fuels will penetrate the Asia-Pacific market (natural gas, nuclear, and renewables) so that in 2030 coal will account for only 60 percent of the fuel for electricity, down from 70 percent today.

Nuclear power generation capacity had been projected to increase by 70 percent by 2030, but the failures at the Fukushima Daiichi plants will reduce these projections. Germany decided to shut down its nuclear power program by 2022. Italy, too, voted to curb its nuclear power program. China, on the other hand, decided to continue its program. Wind and solar power generation capacity will increase; however, their intermittency will keep their percentage of power generated significantly below their percentage of installed capacity.

Global CO_2 emissions are projected to grow by 25 percent by 2030, less than energy demand growth of 35 percent. Emissions will decline in the developed economies but will be offset by increases in the emerging economies. By 2030, the developing nations will account for about two-thirds of energy-related CO_2 emissions. Accelerated gains in energy efficiency and the shift to less carbon intensive fuels will slow the growth in CO_2 emissions. The rapid rise in CO_2 emissions in non-OECD countries and especially in the Asia-Pacific region are due to the continued strong reliance on the most carbon intensive fuel — coal.

By 2030, global liquid fuels demand will be slightly more than 100 million barrels per day (mmbpd), up more than 20 percent. Conventional crude oil will continue to comprise most of the world's liquid supply; however, increasing supplies will come from oil shale, oil sands, biofuels, natural gas liquids, coal-to-liquids, and gas-to-liquids. The question of peak oil weighs natural depletion and exhaustion against extended and enhanced production. Oil production is driven by economics and technology, but there is also a political component — rules governing access to resources and their production. Over the last 150 years, societies increasingly relied on oil, especially for transportation.

Peak oil theories developed based on the natural rise and fall in oil field production. The economist M. King Hubbert predicted in 1956 that United States oil production would peak in the 1970s; he was right. Others applied his theory globally, asserting that oil discoveries and production would not keep pace with demand. But evidence to date does not support this theory. Global production has kept pace with demand as new fields have been discovered and developed in new regions — Angola, Iraq, Brazil, and the Gulf of Mexico — where development and production are increasing. Future global resources appear more than sufficient to meet global demand for at least

40 years. Currently, global cumulative oil production has reached about 1.1 trillion barrels. Unproduced proved reserves total another 1.4 trillion barrels. Analysts estimate there are more than 12 trillion barrels in place yet to be discovered and developed. The keys to this resource development are access, technology, price, and favorable development policies.

Access to oil resources has changed over time. In 1970, the IOCs had full access to 85 percent of the world's oil resources. Today, they have full access to only 7 percent. NOCs now have exclusive control of 74 percent of the world's oil, while permitting limited access to another 14 percent. This shift limits the exploration and development of oil resources and affects the conditions under which they are developed, since the NOCs and their governments set the terms.

Technology and economics are the other keys to unlocking new oil resources. Hubbert's prediction in 1956 was focused on conventional oil and did not take into account the ability to access different kinds of resources. Today, technology and economics make possible the development of a variety of unconventional resources such as oil shale, oil sands and heavy oil. Technology and economics have also made possible the development of conventional oil resources in remote and highly inaccessible areas such as ultra-deepwater or Arctic regions. The enhanced ability to develop these resources, assuming environmental concerns can be allayed, has pushed out into the future the time when global oil production will peak.

The application of modern technology will be expensive. Some estimate that to replace today's declining production while meeting future demand growth will cost about $450 billion annually. Deepwater wells are being drilled from 1,500 feet to 10,000 feet, costing from $30 million to more than $100 million per well. Technology, however, reduces economic and technical risk and leads to a reduction in the cost per barrel of production. New horizontal drilling tools optimize drilling, increase the footage drilled per day and increase reservoir contact. Wells can be drilled out eight miles from the drilling site. Modeling occurs to see how drilling will work even before going into the ground. All of this reduces risk and helps offset the higher cost. Oil is produced from resources not even imagined in Hubbert's era.

Gulf of Mexico deepwater will be a growing resource for United States oil production. The blowout at the Horizon Oil platform and its Macondo well in 2010 was a wake-up call for the industry. A Presidential Commission examined the causes of the blowout and found that the disaster was foreseeable and preventable, that the causes could be traced to mistakes by the companies involved, and that the company decisions revealed systemic failures in risk management that raise questions about the industry's safety culture. Regulatory oversight was also found wanting as regulators did not have the resources or the technical expertise to keep up with increased deepwater activity.

The Commission issued a long list of recommendations for the industry and for regulators, focused on making offshore development safer and more environmentally acceptable.[1] The industry adopted most of these recommendations including the creation of a Safety Institute to develop industry-wide best practice standards. A similar institute created for the commercial nuclear industry after the Three Mile accident is widely considered successful. The Commission also recommended that the industry develop a "culture of safety", look at how other countries handle offshore safety, and make containment technologies broadly available. The public is suspicious of close cooperation between government and industry, but technology is changing so rapidly that such cooperation is essential. As a more prudent operating environment develops, the public must be made aware of the changes and accept them. Transparency in industry-government cooperation may help alleviate the public's concern.

The Commission applauded the responses from industry and regulators. But it is concerned that no Congressional action has been taken, with little prospect of any legislative changes occurring soon. It was not the Commission's intention to halt all offshore drilling,

1 See, *Deepwater: The Gulf Oil Disaster and the Future of Offshore Drilling,* Report to the President, National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling, January 2011, www.oilspillcommission.gov.

since offshore oil and gas development is an important part of the American economy. From the Commission's perspective, drilling offshore and in other high-risk environments such as the Arctic should proceed only if done in a prudent and safe manner to minimize the inherent risks.

North America: New Resources, Environmental Concerns

In North America, oil resource development is in the ascendancy, following closely on the heels of recent increases in gas resource development. The focus in the lower forty-eight states of the United States is on oil shale in areas including Bakken in North Dakota, Eagle Ford in Texas, Mississippian in Mississippi, Niobrara in Colorado, and Utica in Ohio. Gas shale development is still robust, making the United States the world's largest gas producer, but oil shale is the newest major development.

Just when most analysts thought the U.S. oil and gas business was in decline, improved technology (horizontal drilling, hydraulic fracturing — fracking[2], and enhanced seismic imaging) and favorable economics changed the industry. Oil shale production is projected to increase by 3.5 mmbpd by 2020. Gas shale production is projected to increase four fold and comprise 46 percent of domestic supplies by 2035. Based on the upsurge of gas production, there is the strong potential that within five years the United States could export surplus gas supplies in the form of liquefied natural gas (LNG). Such a change could have major economic and political implications for the global gas market.

---

2 Shales are impermeable rock formations that must be broken apart through fracturing, while with conventional drilling the source rock does not have to be fractured to get the liquid or gas out of the ground. With conventional drilling the rule has been to go around or through the shale and not to search for it.

Both oil shale and gas shale rely on similar technology with similar environmental risks. The risks come from fracking, with the remote potential for contamination of groundwater aquifers with drilling fluids or oil or gas — the fracking is done far below the aquifers — and from inadequate well cementing and completion, or improper handling and disposal of waste water produced from the well. With prudent regulation and using best practices, these risks are manageable.

The wide price disparity between oil and gas is the driver behind the new emphasis on oil. Gas prices have been hovering around $5 per 1 thousand cubic feet (mcf) (equivalent to about $30 per barrel of oil), while oil prices for West Texas Intermediate (WTI) have recently fluctuated around $100 per barrel. Two years ago the prices were nearly equivalent and more investment was going into gas shale development. Good returns in gas shale continue even at current prices, but higher oil prices mean stronger returns on capital in oil. Gas shale development also continues because of leases requiring rapid action before they expire. The number of active wells drilled is an important indicator of domestic oil and gas activity, and two trends are noticeable in recent years: a shift to horizontal drilling and a shift toward oil.

The top five oil shale plays contain almost 90 billion barrels of oil — three times the amount of conventional proved reserves. The American gas resource base also is substantial — 100 years of gas at current consumption levels — with gas shale supplies making the substantial difference for the future. The development of shale gas in the United States means that substantial gas supplies will be forthcoming even at today's moderate prices.[3]

Large capital requirements will be necessary to develop oil and gas shale resources — $1.5 trillion will be required for the 150,000 oil wells needed to develop oil shale. Infrastructure will cost another 20 percent. About $50 billion will be needed annually to drill 8,000

3 MIT recently published a comprehensive, interdisciplinary study, the result of three years of analysis, "The Future of Natural Gas." See, http://mit.edu/mitei/research/studies/naturalgas.html

to 10,000 gas shale wells at $3 to $12 million each, with infrastructure costs additional.

To meet large capital needs, small to medium sized independents normally use their cash flow. But these companies are currently exceeding their cash flow by 20 to 100 percent. Outside financial assistance will be necessary. Private and public equity offerings can provide partial financings with the remainder coming from mergers and acquisitions and joint ventures. Capital from larger companies and super majors is flowing into the oil sector — over $55 billion already invested. IOCs continue to play a significant role with over $25 billion already invested. Outside development financing for the gas sector is coming from IOCs, NOCs and Asian companies.

Canadian oil sands, another unconventional resource, are increasing North American oil production and providing an additional margin of energy security from locally produced resources. Canada now ranks third globally in proved oil reserves with almost 175 billion barrels. It is one of the few countries that can expand its production, from today's 1 mmbpd oil sands production to 3.5 mmbpd in the next 10 to 20 years. Additional production can be transported from Alberta to the U. S and all the way to the Gulf Coast through the existing Keystone Pipeline and the Keystone XL Project expanding and extending it.[4]

The Keystone XL Project represents a $13 billion infrastructure investment. Supporters argue that it offers direct benefits to the U.S. through enhanced energy security, jobs, and tax revenues, although some oppose development of both the pipeline and oil shale on environmental grounds. They argue that GHG emissions from oil sands are 20 percent higher than from conventional oil, and that those from oil shale are as much as 73 percent higher. Both use substantial amounts of water in their production — every barrel of oil produced from oil shale requires three to five barrels of water, while

4 A permit to build and operate the Keystone Pipeline expansion — Keystone XL — is required from the United States State Department. The Department must make a "national interest determination" in evaluating the merits of the pipeline. Environmental groups are urging the State Department to include climate change as well as other environmental issues in making its national interest determination.

oil sands consume up to four barrels of water for each barrel of oil. Mine tailing ponds associated with oil sand production can pollute surrounding water resources, while mining disturbs vast amounts of land. Oil sands and Keystone XL Pipeline proponents indicate that most of the water used is recycled, land use impacts are more limited than with earlier production methods, and GHG emissions are smaller than coal power generation and are decreasing as better control is undertaken. They also note that if the United States blocks the import of the oil, Canadian oil will be shipped to Asia and the United States will import more oil from overseas, with higher costs and GHG emissions due to the longer transportation routes.

Opponents also challenge the energy security benefits of the Keystone XL Project. They claim the U.S. still will have to import oil from unfriendly and unstable sources. They state the way to break U.S. oil dependency is to move to cleaner, renewable fuels and more transportation options. With this approach, the U.S. could save up to 7 million barrels per day of oil by 2030, lessening the country's need for new oil supplies from high carbon sources. The energy security discussion among Forum participants questioned how much security we can afford and how we should analyze environmental impacts versus the comfort of secure energy supplies from a friendly neighbor. "Life is full of dilemmas," asserted one participant, concluding there often are no easy answers to hard questions.

Critics of oil shale and oil sands development propose a series of policies that could lead to a 7 mmbpd reduction in U. S. oil consumption. These include phasing out fossil fuel subsidies (estimated at $4 billion/year); halting unconventional fuels expansion and infrastructure, including the Keystone Pipeline expansion; moving towards California's low-carbon fuel standard (LCFS)[5]; and regulating greenhouse gas emissions. Until clean energy can contribute

5 Under a LCFS, transportation fuels follow a gradual trajectory away from today's petroleum to fuels that emit less carbon over their lifecycle. As a fuel-neutral performance standard based on carbon emissions, the LCFS does not ban any fuel type but instead rewards fuels that emit the least carbon pollution per unit of energy. Examples of clean, low carbon fuel include electricity (depending on the fuel source of the electricity) and advanced environmentally sustainable biofuels. Fuels made from oil sands or oil shales, on the other hand, emit more carbon than conventional gasoline fuel because extraction and upgrading are energy intensive.

significantly to domestic energy supplies, some argue that natural gas is an important bridge to the future.

Mandated by the Supreme Court to regulate GHG emissions under the Clean Air Act, the EPA issued proposed rules to regulate emissions from electric power generators, large industrial boilers, and refineries. Refiners worry about the large investment required to meet the new standards and the uncertainty generated by the timing of their implementation, noting that GHG emissions from refineries are about one tenth of those from electric power industry. The rules are proposed to take effect in November 2011.

A shift in the quality of world crude oil supplies is also affecting refinery costs. Supplies of the preferred light density crude are diminishing. Refiners invested in their refineries to allow the use of more plentiful, heavier density crude oils that have higher carbon content and higher CO_2 emissions. New environmental rules targeting these heavier crudes are creating a challenge. Under a proposed California low carbon fuel standard, some heavy crude oils, including California crudes, would be grandfathered into the system. Others, such as crude from Canadian oil sands, would not be permitted. Refiners now using crude oil from oil sands would have to replace it at potentially higher cost in order to satisfy the new rules, and they fear that the EPA will follow California's lead and impose a LCFS for all refiners. They argue that the LCFS undermines North American energy security and that North American crude oil should stay in North America. Some indicate that with a global oil market and relatively free trade it should not matter where oil is refined as long as demand for products is met. Domestic refiners counter that the American refining industry means about 9 million domestic jobs directly and indirectly. Refiners make more than just gasoline and diesel; they make a slate of petrochemicals that are used in a wide variety of products such as plastic bottles for water and other liquids. Would we need to import these if domestic refining were not available?

International Supply: Supply Growth, Supply Decline

Internationally, among the bright prospects for new supplies of oil and gas are Iraq and Brazil. On the other hand, Mexico and Venezuela, once considered robust oil suppliers, are now struggling to sustain current production. Russia, with some of the largest resource potential in both and oil and gas, is maintaining its current production, but future development is dependent upon new incentives. China, the world's largest energy consumer, is developing policies to curb its energy appetite even as it searches for new sources of oil and gas internally and internationally.

Iraq

Iraq has the largest cluster of mega oil fields (six) in the world, with 60 billion barrels of reserves within a 100 kilometer radius. Some analysts think that Iraq may have larger oil resources than Saudi Arabia. Iraq auctioned exploration and production (E&P) areas to IOCs from the United States, China, UK, Netherlands, Italy, Korea, Malaysia, Russia, Norway and Japan, using a technical service contract format to avoid political problems with equity ownership of resources. These oil fields now produce about 1.5 mmbpd (Iraq's total production exceeds 2 mmbpd). The IOCs bid to increase production to more than 10.7 mmbpd but must work with Iraqi oil companies to ensure agreement with all investment decisions. The IOCs are likely to receive a return of 10 to 15 percent over the life of the contracts. The contracts are structured to reward speed of production, not efficiency and the best technology available. After these auctions the Iraqi government raised its overall production goal from a conservative 6 mmbpd to an ambitious 12 mmbpd. Most analysts think the 6 mmbpd goal is more realistic, but even at that level Iraqi oil production is destined to increase dramatically in coming years. Iraq also has significant deposits of natural gas, especially in the north. Gas development is lagging behind oil development but is likely to occur in the future.

These expectations are good news for Iraq, and there is great optimism over future Iraqi oil production entering international markets by 2014. With the government's share of profits exceeding 90 percent, government revenues from production could double by 2015 and quadruple by 2020. This large cash infusion could go a long way to stabilizing the country by providing a huge boost to internal development and rising incomes.

All analysts believe that Iraq is one of the last great oil provinces, one that has been vastly underexplored and underdeveloped. But many are less sanguine about the 2014 date. The development of Iraq's oil fields and its export infrastructure faces immense problems. Extensive mine fields still exist and must be eliminated. The Oil Ministry will supervise the biggest projects with its consequent red tape and delays. The Ministry also will process cost recovery invoices, and the timeliness of payment and auditing techniques are highly uncertain. Manpower also will be a factor as IOCs struggle with bureaucratic delays in getting people in and out of the country.

Brazil

Brazil, too, has favorable prospects with its new offshore E&P areas. Since 1953, Brazil's oil reserves have grown to more than 14 billion barrels, and production has increased from virtually nothing to 2 mmbpd today. Deepwater production is centered in the offshore Campos and Santos basins. Accelerating investment will allow Brazilian oil production to reach 5 mmbpd in the future.

The newly leased areas in the Santos Basin present significant challenges: the fields are 200 miles offshore; water depth is in excess of 5,000 feet; a massive salt layer must be penetrated before reaching the oil reservoirs 18,000 feet below the ocean floor; CO_2 emissions and associated natural gas must be controlled; and distribution facilities must be built. Extremely high investment is required along with major technological innovation to produce and market the oil. Years of coordinated work among the various participants — Petrobras (Brazil's government owned company), IOCs, service companies, research organizations — will be necessary. First production is expected in 2013-2017 with an additional 1 mmbpd or more expected by 2018. The new E&P area in the Santos Basin will expand Brazil's reserve base significantly. BP's latest statistical review estimated Brazil's oil reserves at about 14 billion barrels. Brazil estimates its reserves at 28-30 billion barrels — double BP's estimate. It is this more optimistic level of reserves that would sustain a rapid increase in production to more than 5 mmbpd of oil equivalent by 2020 (including both oil and gas).

Russia

Russian oil and gas production is a success story tempered by an uncertain future. Today Russia is the world's largest oil producer, producing 10.1 mmbpd (12 percent of global production) and the second largest natural gas producer (18 percent of global production). Oil production is aging and declining at a rate of 1-2 percent per year, and gas production is declining at a rate of 3-3.5 percent per year. Underinvestment exists in both oil and gas exploration and development, a legacy from Soviet times. During the last five years, oil exploration declined 50 percent and development declined 70 percent. Altering these declines is unlikely in the future. The tax regime lacks investment incentives, with extremely high marginal tax rates on exported crude oil — 90 percent — while all taxes are based on revenues without regard to costs. Under the current tax regime, 80 percent of new oil fields and 50 percent of old oil fields are uneconomic.

Since 2001 Russia's oil strategy has emphasized exports, because a substantial portion of Russia's budget depends on oil export taxes. Russian companies were urged to increase production and exports, which rose 56 percent and 70 percent respectively, while internal consumption was held relatively steady, increasing only 9 percent. This purposeful strategy was aided by a significant expansion of Russia's export pipelines to its principal market — Europe. Russia has three main export routes: the Druzhba Pipeline delivering crude oil directly to Central Europe via Belarus, the Baltic Pipeline (BPS) delivering crude oil to European ports via Russian ports on the Bay of Finland, and tanker deliveries through the Bosporus to European ports.

Additional export routes either are under construction or planned. A planned expansion of BPS would divert oil from Druzhba furthering Russia's desire to control its own export routes while simultaneously avoiding Belarus. The ESPO (East Siberia Pacific Ocean) pipeline is under construction, with its first phase complete to China aided by Chinese investment. The second phase to the Pacific Ocean will be operational in the next couple of years. Other speculative pipeline projects are on the drawing board. There is no economic rationale for all of these new pipelines, since no new capacity is needed to relieve bottlenecks, and the availability of additional oil to fill them is doubtful. With overcapacity, per barrel transit costs will rise, undermining the economics of the existing pipeline system.

Russian gas markets also are undergoing rapid change. Finding and developing gas is becoming more difficult and expensive just as it is becoming more important domestically due to economic growth. Export markets are in disarray. Gas exports continue to be one of the two pillars of the Russian economy, along with oil, contributing significantly to Russia's budget. Together the two provide for more than 50 percent of revenues. Russia will need to maintain its export capacity if this pillar of the economy is to remain robust.

Gazprom's production, about 85 percent of the total, relies on aging declining fields. Gazprom can meet its short-term and mid-term contractual obligations from these fields, but the long-term is very uncertain. Gazprom is shifting its strategy to focus more on its export markets (Gazprom, by law, is the only company that can export gas), leaving independent gas companies and oil companies to produce and sell more into the domestic market through Gazprom's pipelines.

Russia's European gas markets were under pressure from the recent economic downturn, with Russia losing substantial market share. The cause was high Russian gas prices linked contractually to oil prices (gas prices follow oil prices with a six to nine month lag). As demand dropped, European buyers demanded contract renegotiation with Russia, who acceded and reduced supplies. Russia also moved some of its gas to spot pricing (about 15 percent of some volumes to its largest German customers and 7-8 percent of overall), which was substantially lower than contract prices. As the recession ended, gas demand rebounded and Russia's gas exports surged. Russia continues to rely on oil-linked gas prices but recognizes that it faces competitive difficulties with some customers, especially in Germany. Until Russia and Europe work out a new model of gas pricing, Russia may wind up the loser in European gas markets. The last several years provided strong evidence that its dependency on the European market can create severe problems, providing an incentive to access the Chinese market. Discussions with the Chinese on pricing issues between the two countries have been ongoing for years, with no resolution in sight.

China

China's oil and gas picture is in flux. From 1963 and its discovery of its Daqing oil field, China based its oil policy on growing domestic supplies. For thirty years this plan worked; however, since 1993 China has been a net importer. Today China is the second largest oil importer after the United States, importing more than 50 percent of its needs. With this shift, Chinese oil companies refocused on overseas investment. They used their large cash resources to invest in foreign operations — in 2010 Chinese companies were the largest overseas investors at $18 billion.

The oil industry in China is characterized by three powerful state-owned oil companies — CNPC (Chinese National Petroleum Corporation), Sinopec (Chinese Petrochemical Corporation) and CNOOC (Chinese National Offshore Oil Corporation) — and a weak regulator. The National Energy Administration has about 80 people who are unable to regulate. State owned oil companies retain their ministerial status along with other ministries. The Communist party appoints the highest ranking ministry officials. While the oil companies retain substantial power, there is a downside. Company officials have been prosecuted and jailed.

Chinese oil companies generate significant cash from their upstream investments. They do not pay dividends and have few domestic opportunities for reinvestment. They thus must look internationally to reinvest and are world leaders compared to other IOCS. The Chinese companies invest and operate in politically risky environments, such as Sudan, and are increasing imports from the Middle East just as American imports from that region are declining. One result is increasing influence for China in international politics.

China has significant gas shale potential. It faces serious impediments in lack of pipeline access to the shale areas. China will not see much shale gas development in the next five years. The NOCs are the only domestic players as China does not have an independent gas sector. Since the NOCs are the only vehicle for E&P and they are pre-occupied in other areas, it will take at least five years to re-orient to look at shale.

Mexico and Venezuela

These two countries have significant oil reserves. Mexico has 11.4 billion barrels, and Venezuela, with 211.2 billion barrels, has the world's 2nd largest reserves. They also have relatively large oil production (Mexico: 2.9 mmbpd; Venezuela: 2.5 mmbpd) and important gas reserves and production. But due to government policies, there is not much hope in either country of increasing oil production.

Mexico's current situation is tempered by its history. In the early 20th century, United States companies invested in Mexico and were awarded equity reserve positions. In 1938, Petroleos Mexicanos (Pemex) was created. In 1940 the constitution was amended, with the government taking back all reserves and awarding them to Pemex. Foreign companies were expelled. To change this situation, a constitutional amendment would be required, consisting of a vote by two-thirds of the Congress and a majority of all states.

Pemex made some important discoveries, particularly Cantarell, one of the world's largest offshore oil deposits. By 1965 the tax burden on Pemex increased to 60-70 percent of revenues, more than 100 percent of net income, leaving nothing for re-investment. The success with Cantarell masked internal Pemex problems. Today, underinvestment is apparent. Cantarell production is down 74 percent from its 2004 peak. Reserves are down to 11.4 billion barrels from a high of 25 billion. Current production leaves only ten years of production. In 2008, reforms were instituted allowing performance based contracts. The Supreme Court finally approved the contracts in 2010. Even with these new contracts the question remains whether there will be improvements in the oil sector. Without such improvements, and without foreign investment, Mexico will soon be an importer.

In Venezuela, oil production was 3.5 mmbpd, with expansion potential to 4.1 mmbpd, when President Hugo Chavez took over in 1999. The new regime changed all the rules and contracts. Today production is down to 2.5 mmbpd or less. Large IOCs, including ExxonMobil and Conoco, left the country due to contract changes and are now in court or arbitration fighting for their rights.

President Chavez relies on the revenues from the Venezuelan oil company Petroleos de Venezuela (PdVSA) to fund his social programs. PdVSA has $120 billion in debt, with little funding left over for re-investment after debt servicing. While new companies from China and Russia are entering Venezuela, the question is whether Venezuela can increase its production back to previous levels.

Transportation Fuels: Alternatives to Oil

Natural Gas

Large shale gas supplies and the resulting lower prices enhance the prospect of using natural gas for transportation. The National Petroleum Council is looking into alternative transportation fuels for the next 40 years, including how large a role natural gas can play in light duty and heavy duty market segments. In the United States, natural gas is already penetrating transit and refuse truck markets, taking 10-20 percent of transit new sales and more than 20 percent of refuse truck orders today. In other parts of the world, natural gas vehicles (NGVs) are making significant inroads in light duty markets, especially in Asia and Latin America, where 13 million vehicles already are on the road.

Natural gas for vehicles can be compressed (CNG) or liquefied (LNG) and used instead of gasoline or diesel. The current and expected future large differential between natural gas prices and diesel/gasoline prices makes using natural gas appear attractive. For diesel, this differential now is in the range of $1.50-$1.75 per gallon. The heavy duty bus and truck market is more favorable for penetration than the automobile market since heavy duty vehicles can use central fueling stations for fleets (buses, trash trucks) or corridor fueling stations for long-haul trucks.

Obstacles exist to the development of a robust NGV market, of course, including the need to bring more manufacturers into the business of mass production of engines and vehicles, and building new fueling stations and infrastructure to meet the growing demand. Another impediment is the large difference in the density of fuels. Diesel can move a heavy duty vehicle 650 miles on 100 gallons of fuel. A LNG vehicle could go 380 miles, while a CNG vehicle could go about 170 miles on the equivalent of 100 gallons of CNG (at 3600 psi). Another obstacle is the higher initial cost of a heavy duty NGV versus diesel — which varies depending on the class of vehicle from transit to refuse to commercial trucking — although there is an average payback of under three years in many cases with today's large fuel price differential.

Electricity

Electric powered vehicles (EVs) were sold during the 1990s but did not meet with great success due to cost, battery capacity and vehicle range. Most potential purchasers feared that they would run out of electricity without abundant opportunities to recharge. Despite the demise of those EVs, they led to greater understanding of electric propulsion systems, and two new commercially available options were introduced in 2010 — the Chevrolet Volt and the Nissan Leaf.

Today's EVs rely on lithium ion batteries rather than lead acid or nickel hydrates. The lithium ion batteries provide greater range, but they are less stable. Researchers are looking into other options that may be preferable in the future.

Comparing oil-based fuels with batteries for a comparable distance (500 km), diesel fuel is lighter than batteries — 33 kg vs. 540 kg — and requires less volume — 37 liters vs. 360 liters. Today, there are limited EV options on the road. Some manufacturers rely only on batteries, e.g., the Nissan Leaf, while others are hybrids, relying on a combination of batteries and gasoline engine, e.g., the Chevrolet Volt. The industry is watching to see the experience with both. The most serious consumer problem is range fear — the fear of running out of electricity without a recharging facility handy. The Volt provides a battery that powers the vehicle for at least 40 miles, the maximum range about 78 percent of commuters travel each day. The back-up gasoline system extends the range by recharging the battery while the car is in operation. To recharge the battery at home or work using a 120 volt system takes ten hours; a 240 volt system requires four hours. Market penetration for EVs depends upon developing the charging infrastructure at home, work, or public locations. The higher cost of the EVs and the cost of recharging equipment also are currently significant impediments to consumer acceptance, despite tax incentives.

Biofuels

The biofuels industry today relies on corn ethanol — present production is 13 billion gallons. Most gasoline in the United States contains ten percent ethanol, used as an octane enhancer and oxygenate to reduce low level ozone emissions, which cause smog. The renewable fuel standard (RFS) passed by Congress requires petroleum marketers to blend up to 36 billion gallons of biofuels by 2022, one quarter of total gasoline supply, to diversify America's liquid fuel sources. Supporters argue that ethanol is a domestic fuel and can diminish the need for gasoline produced from foreign-sourced oil.

A federal tax credit of 54 cents per gallon of ethanol subsidizes ethanol. Supporters argue that oil is one of the more heavily subsidized fuels, with direct tax subsidies of $6.5 billion per year and hidden costs through military expenditures for global protection of $67 to $83 billion and imported oil costs of $340 billion or more annually. They challenge the argument that corn-based ethanol raises prices for food. Only about 35-40 percent of the corn crop goes to ethanol, and about a third to half of this amount is used as animal feed after the distillation process. Higher food costs are attributable primarily to marketing (about 85 percent of total costs) and transportation costs, not to the underlying cost of corn. Ethanol supporters also dispute the argument that Brazil is deforesting to clear farmland for ethanol, or for food to replace crops used for ethanol, as deforestation decreased substantially even as ethanol use in Brazil and elsewhere increased.

The benefits of ethanol include less carbon intensity than gasoline or diesel and reduced oil imports. Proponents assert most gasoline consumption, now about 140 billion gallons per year, can be replaced by ethanol. This would require lifting the restrictions on the amount of ethanol in gasoline — now set at 10 percent, with EPA proposing a 15 percent cap — or if more flex-fuel cars were built and more pumps installed that could use E85 (85 percent ethanol). Installing the pumps would be more difficult, with a cost of up to $750,000 to $1 million each.

About 60 percent of the 36 million gallons per year required by 2022 by the RFS must be "advanced biofuels," which must cut greenhouse gas emissions by 50 percent. The cost of ethanol from cellulose, the leading candidate, is quite high, about $3.00 per gallon, although this is expected to decline to under $1.00 per gallon with technology advances and more cellulosic refineries.

Fuel Efficiency

There are three keys to increasing the fuel efficiency of automobiles: reducing weight, reducing drag with better body design, and reducing rolling resistance by tire design improvements. All three can be achieved without significant increases in automobile costs since there is a lack of correlation between price and innovative designs to reduce weight, drag or rolling resistance. The focus by many auto manufacturers is on reducing weight by introducing ultra-light materials.

Using ultra-light and ultra-strong materials can triple fuel efficiency and, by requiring fewer costly batteries, help make electric propulsion systems economically feasible. Carbon fiber materials are ultra-light and ultra-strong. They can be produced quickly and easily with automobile assembly systems using tens instead of hundreds of body parts, stamped with one low-pressure die per part rather than an average of four high-pressure die sets. This could reduce tooling costs by 95-99 percent.

Introducing these carbon fiber materials into manufacturing processes, however, would entail significant transition costs. In addition, today's materials — aluminum and steel — can be recycled, while carbon fiber cannot. Special "feebates" or rebates to the consumer can assist in lowering costs to the consumer during this transition. Savings from today to 2050 from the introduction of light weighting, drag reduction and rolling resistance reduction could be as high as $3.8 trillion.

Options

Technologies exist today to move in multiple directions. Each direction involves transition costs and new infrastructure, and meeting consumer preferences can make the changes more difficult. With natural gas, altering the internal combustion engine is a small cost; the significant cost occurs with fueling infrastructure and auto design to accommodate the fuel tanks. With electricity, several hurdles remain, including battery technology, battery cooling, refueling and bringing the cost of the vehicle within the range most consumers are willing to pay. Interim solutions may be desirable (frequent charging for example) as consumer acceptance increases. With biomass, the fuel can use today's infrastructure, although resource use (land, water) is extensive and costly. Fuel cells are maturing rapidly, but cost is still the major factor in making this option available. Enhanced efficiency is achievable but can be very expensive. The sunk cost associated with today's technology is very high, taking years to pay off. Changing to a very different technology and writing off sunk costs is not likely to occur without mandates.

Conclusions

- Oil, natural gas and coal will remain the dominant fuels for the next twenty years while renewable energy will grow the fastest, but from a very small base. Nuclear energy's future is less certain due to the recent nuclear disaster in Japan.

- The developing world will demand more energy while the developed world will curb its energy use by increasing efficiency faster than it uses energy. The Asia-Pacific region will grow the most, with China and India the two dominant energy consumers.

- Greenhouse gas emissions will continue to grow, with developing countries contributing most of new GHG emissions as developed countries find ways to slow their emissions.

- Oil resources are not in danger of running out soon, as more unconventional resources are being developed throughout the world. Peak oil theories are being undermined by higher prices and the application of new technology, especially horizontal drilling and hydraulic fracturing.

- North American oil and gas supplies are increasing as these new technologies are being used to develop unconventional oil and gas shales. Oil sands also are increasing North American supplies.

- Significant environmental issues are associated with the development of the new unconventional supplies, including water use, inadequate well cementing and completion, improper handling of waste water, and the fear of possible contamination of ground water aquifers. These environmental concerns must be managed through prudent regulation and best production practices if this production is to achieve its potential.

- New oil supplies are also coming from Iraq and Brazil where IOCs in partnership with indigenous NOCs are making large investments.

- Sustaining Russian oil production will be difficult due to underinvestment in aging oil fields and lack of adequate incentives for new production. Russia's gas industry faces headwinds as its existing fields decline, new investment is lacking, and pricing issues in Europe may undermine its traditional markets.

- Oil production is lagging in Mexico and Venezuela as domestic policies undermine investment in an aging industry.

- Transportation fuel options other than oil are being developed and include natural gas, electricity, biomass, and efficiency. All hold promise; all present significant impediments to their adoption.

APPENDICES

Agenda

"Global Energy Markets in a Time of Political Change"

Friday, July 15

8:30 am—noon

SESSION I: **The Outlook**

World supply and demand	**Rob Gardner** Manager, Economics and Energy Corporate Strategic Planning, Exxon Mobil
Peak oil – an industry viewpoint	**Janet Clark** Executive Vice President and Chief Financial Officer, Marathon Oil
NPC study – North American Resource Development	**Scott Moore** Vice President of Marketing Anadarko Petroleum Corporation
Deep offshore – prudent development	**Fran Ulmer** Chair U.S. Arctic Research Commission
Drilling technologies and unconventional resources	**Rod Nelson** Vice President, Innovation, and Vice President, Communications and Collaboration, Schlumberger

1:30—5:00 pm

SESSION II: Oil Supply – North America

Impact of possible EPA GHG regulation	**Gary A. Schoonveld** Manager, Fuels and Regulatory Affairs ConocoPhillips
Oil sands and Keystone XL Pipeline	**Alex Pourbaix** President, Energy and Oil Pipelines TransCanada
Oil shale and other unconventional	**Bill Marko** Managing Director Jefferies & Co.
Environmental issues	**Susan Casey-Lefkowitz** Director, International Program National Resources Defense Council

Saturday, July 16

8:30 am—noon

SESSION III: International Supply

Iraq	**Lou Pugliaresi** President Energy Policy Research Foundation
Brazil	**Gustavo Amaral** Upstream Vice President Petrobrás Americas
Russia	**Adnan Vatansever** Senior Associate Carnegie Endowment
China	**Trevor Houser** Partner, Rhodium Group
Mexico & Venezuela	**Luis Giusti, CSIS,** and Former CEO Petróleos de Venezuela

1:30—5:00 pm

SESSION IV: Alternative Transportation Fuels

NPC study: Future Transportation Fuels	**Shariq Yosufzai** Vice President, Chevron
Natural gas	**Michael Gallagher** Senior Advisor and former President Westport Innovations
Electricity	**Mustafa Mohatarem** Chief Economist, General Motors
Biomass	**Gen. Wesley C. Clark** Co-chair, Growth Energy
Fuel efficiency	**Amory Lovins** Chairman and Chief Scientist Rocky Mountain Institute
Evaluating the options	**Bill Reinert** National Manager Advanced Technology Group Toyota USA

Sunday, July 17

8:00—11:30 am

SESSION V: Natural Gas Supply

MIT study: Future of Natural Gas	**Ernie Moniz** Director – MIT Energy Initiative, and Former Undersecretary of Energy
Economics and finances of shale production	**Claire Farley** Co-founder, RPM Energy LLC
Shale gas – prudent development	**Paul Hagemeier** Vice President for Regulatory Affairs Chesapeake Energy
Potential for US gas exports	**Charif Souki** Chief Executive Officer Cheniere Energy

Participants

Gustavo Amaral
Upstream Senior Vice President
Petrobrás Americas
10350 Richmond Ave.
Ste. 1400
Houston, TX 77042

William Arnold
Professor in the Practice of
Energy Management
Rice University
2220 Stanmore Dr.
Houston, TX 77019

Porter Bennett
CEO
BENTEK Energy
32045 Castle Ct.
Evergreen, CO 80439

Adam Bergman
Director
Deutsche Bank
101 California St, 48th Fl.
San Francisco, CA 94111

Christiane Bonomo
Energy Desk
Embassy of Brazil
1025 Thomas Jefferson St., NW
Ste. 300W
Washington, DC 20007

Jason Bordoff
Associate Director – Energy
and Climate, Council on
Environmental Quality, and
Senior Advisor – Energy
and Environmental Policy,
National Economic Council
730 Jackson Pl., NW
Washington, DC 20003

Joseph Caggiano
Senior Consultant
Chevron
6001 Bollinger Canyon Rd.
Bldg. E 1176
San Ramon, CA 94583

Susan Casey-Lefkowitz
Director International Program
Natural Resources Defense Council
1200 New York Ave., NW
Ste. 400
Washington, DC 20005

Janet Clark
EVP & CFO
Marathon Oil Corporation
5555 San Felipe, Ste. 4131
Houston, TX 77056

Gen. Wesley Clark
Co-Chair
Growth Energy
777 North Capitol St., NE
Ste. 805
Washington, DC 20002

Leonard Coburn (Rapporteur)
President
Coburn International Energy Consultants
2828 Albemarle St., NW
Washington, DC 20008

Jack Derickson
Project Manager
Chevron
6001 Bollinger Canyon Rd.
Room E1188
San Ramon, CA 94583

Theodore Eck
Energy Consultant
IDA
1052 Rt. 10, PO Box 8
Orford, NH 03777

Lisa Epifani
Member
Van Ness Feldman
1050 Thomas Jefferson St., NW
Ste. 700
Washington, DC 20007

Claire Farley
Co-Founder
RPM Energy
600 Travis, Ste. 7225
Houston, TX 77005

Michael Gallagher
Senior Adviser and Former President
Westport Innovations Inc.
#101-1750 West 75th Ave.
Vancouver, BC V6P 6G2
Canada

Paula Gant
Senior Vice President – Policy and Planning
American Gas Association
400 North Capitol St., NW
Washington, DC 20001

Robert Gardner
Manager, Economics & Energy
Corporate Strategic Planning
Exxon Mobil Corporation
5959 Las Colinas Blvd.
Irving, TX 75039

Luis Giusti
Senior Advisor, CSIS, and Former CEO
Petróleos de Venezuela
1800 K St., NW, Ste. 400
Washington, DC 20006

Paul Hagemeier
Vice President – Regulatory Compliance
Chesapeake Energy Corporation
PO Box 18496
Oklahoma City, OK 73154

John Hanger
Special Counsel
Eckert Seamans Cherin & Mellott
213 Market St.
Harrisburg, PA 17101

Paul Hoenmans
Former Executive Vice President
Mobil Oil Corporation
PO Box 9608
Aspen, CO 81612

Trevor Houser
Partner
Rhodium Group
10 East 40th St., Ste. 3601
New York, NY 10016

James T. Jensen
President
Jensen Associates
49 Crescent St.
Weston, MA 02493

David Jhirad
Professor and Director
Energy Resources and Environment Program
Johns Hopkins University School of Advanced International Studies
1717 Massachusetts Ave., NW
Room 741
Washington, DC 20036

Fred Julander
President
Julander Energy Company
475 17th St., Ste. 700
Denver, CO 80202

Yonghun Jung
Counselor to the Minister
Ministry of Knowledge Economy
88 Gwanmoon-Ro, Gwacheon-Si
Gyeonggi-Do 427-723
Republic of Korea

Melanie Kenderdine
Executive Director
MIT Energy Initiative
Masssachusetts Institute of Technology
77 Massachusetts Ave.
Building E19 - 307H
Cambridge, MA 02139

Kenji Kobayashi
President
Asia Pacific Energy Research Centre
Inui Bldg. – Kachidoki 11F, 1-13-1 Kachidoki, Chuo
Tokyo, 104-0054
Japan

Raymond Learsy
Author
PO Box 36
Sharon, CT 06069

Michael Levi
David M. Rubenstein Senior Fellow for Energy and the Environment
Council on Foreign Relations
58 East 68th St.
New York, NY 10065

Amory Lovins
Chairman and Chief Scientist
Rocky Mountain Institute
1739 Snowmass Creek Rd.
Snowmass, CO 81654

Jan Mares
Senior Policy Advisor
Resources for the Future
1616 P St., NW
Washington, DC 20036

William Marko
Managing Director
Energy Investment Banking
Jefferies & Company, Inc.
Three Allen Center
333 Clay St., Ste. 1000
Houston, TX 77002

Mustafa Mohatarem
Chief Economist
General Motors
Public Policy Center
MC: 482-C27-C81
300 Renaissance Center
Detroit, MI 48265

Ernest Moniz
Director, MIT Energy Initiative
Cecil and Ida Green Professor of Physics and Engineering Systems
Masssachusetts Institute of Technology
77 Massachusetts Ave.
Building E19 - 307D
Cambridge, MA 02139

Scott Moore
Vice President of Marketing
Anadarko Petroleum Corporation
1099 18th St., Ste. 1800
Denver, CO 80202

Espen Myhra
Energy Counselor
Royal Norwegian Embassy
2720 34th St., NW
Washington, DC 20008

Rod Nelson
Vice President, Communications
Vice President, Innovation and Collaboration
Schlumberger
5599 San Felipe, 17th Fl.
Houston, TX 77056

Richard Newell
Gendell Associate Professor of Energy and Environmental Economics
Duke University
Box 90227
Durham, NC 27708

Boyko Nitzov
Director of Programs, DPEC
The Atlantic Council
1101 15th St., NW
Washington, DC 20005

Alex Pourbaix
President, Energy & Oil Pipelines
TransCanada Corporation
450 1st St., SW
Calgary, AB T2P5H1
Canada

Tom Price
Senior Vice President
Corporate Development & Government Relations
Chesapeake Energy Corporation
6040 North Western Ave.
Oklahoma City, OK 73118

Lucian Pugliaresi
President
Energy Policy Research Foundation
1031 31st St., NW
Washington, DC 20007-4401

Heliodoro Quintero
International Oil Consultant
H.Q. Consultants
Av Libertador, Resid
Jardin Bello Campo
Torre B, Piso 2, Ofic. 2D
Caracas, 1080
Venezuela

Jim Ragland
Director
Economic Research Group
Aramco Services Company
1667 K St., NW, Ste. 1200
Washington, DC 21012

Kinkead Reiling
SVP Corporate Development
Amyris
5885 Hollis St., Ste. 100
Emeryville, CA 94602

Bill Reinert
National Manager
Toyota Motor Sales, Inc. USA
19001 S Western Ave., HQ42
Torrance, CA 90501

Thomas Roberts
Member
Van Ness Feldman
1050 Thomas Jefferson St., NW
Washington, DC 20007

Ralph Samuelson
Vice-President
Asia Pacific Energy Research Center
Inui Building Kachidoki 11F
1-13-1 Kachidoki
Chuo-ku, 104-0054
Japan

Gary Schoonveld
Manager, Fuels & Regulatory Affairs
ConocoPhillips
600 N. Dairy Ashford Rd.
Houston, TX 77079

Taylor Shinn
Senior Director
Corporate Development
Chesapeake Energy Corporation
2216 Old Pond Rd.
Edmond, OK 73013

Aleksey Shishayev
Economic and Energy Counselor
Embassy of the Russian Federation
2650 Wisconsin Ave., NW
Washington, D.C. 20007

Si Jinsong
Second Secretary
Embassy of China
3505 International Pl., NW
Washington, DC 20008

Kyle Simpson
Senior Legislative Advisor
Hogan and Lovells
555 Thirteenth St., NW
Washington, DC 20004

Richard Smead
Director
Navigant Consulting Inc.
909 Fannin, Ste. 1900
Houston, TX 77005

Charif Souki
Chairman and CEO
Cheniere Energy, Inc.
700 Milam St., Ste. 800
Houston, TX 77002

Gregory Staple
Chief Executive Officer
American Clean Skies Foundation
750 1st St., NE, Ste. 1100
Washington, DC 20002

Judith Zee Steinberg
Former Executive
Mobil Oil Corporation
PO Box 9608
Aspen, CO 81612

Jason Switzer
Director, Corporate Consulting
Pembina Institute
219 19th St., NW
Calgary, AB T2N 2H9
Canada

Fran Ulmer
Chair, US Arctic Research Commission
420 L St., Ste. 315
Anchorage, AK 99501

Adnan Vatansever
Senior Associate
Carnegie Endowment
1779 Massachusetts Ave., NW
Washington DC, DC 20036

Philip Verleger
Professor
University of Calgary
540 Fox Run Dr.
Carbondale, CO 81623

Andrew Ware
Senior Strategic Planning Analyst
Cheniere Energy
720 Kearney St.
Denver, CO 80220

Michael Webber
Assistant Professor
Center for International Energy and Environmental Policy
The University of Texas at Austin
1 University Station, C2200
Austin, TX 78712

Bill White (Forum Chair)
Chief Executive Officer
White Interests
1415 Louisiana St.
Houston, TX 77002

Shariq Yosufzai
Vice-President
Chevron
6001 Bollinger Canyon Rd., Bldg. E
San Ramon, CA 94583

Staff:

David Monsma
Executive Director
Energy and Environment Program
The Aspen Institute
One Dupont Circle, Suite 700
Washington DC 20036

Nicole Alexiev
Deputy Director
Energy and Environment Program
The Aspen Institute
One Dupont Circle, Suite 700
Washington, DC 20036

John A. Riggs
Senior Fellow
Energy and Environment Program
The Aspen Institute
One Dupont Circle, Suite 700
Washington DC 20036

Tim Olson
Project Manager
Energy and Environment Program
The Aspen Institute
One Dupont Circle, Suite 700
Washington DC 20036