Oil and Gas in a Changing World

2009 Forum on Global Energy, Economy, and Security

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Foreword

The Aspen Institute organized the first Forum on Global Energy, Environment and Security in 2005. In recognition of increasingly globalized energy markets and of the strong links between energy and national economic and security concerns, an international group of experts assembles annually to share information on these intersecting issues. A dialogue format is used to encourage new, collaborative, cross-disciplinary thinking on issues of national and global importance. A few brief presentations begin each half-day session, but the majority of the time is reserved for discussion. An informal atmosphere and a not-for-attribution rule encouraged candid exchanges and creative thinking.

The topic in 2009 was "Oil and Gas in a Changing World," reflecting the turmoil caused by the severe economic recession and highly volatile oil and gas prices. The Forum co-chairs were Luis Giusti, Senior Advisor to CSIS and former Chairman and CEO of Petroléos de Venezuela, S.A. (PDVSA); and Joseph A. Stanislaw, independent senior advisor to Deloitte LLP, CEO of The JAStanislaw Group, and former CEO of Cambridge Energy Research Associates. Their many years at the center of U.S. and global energy and security policy discussions allowed them to pose relevant questions and draw out key insights. The highly qualified group of speakers provided a wealth of information and a variety of perspectives, and the diverse expertise of the participants contributed substantially to the richness of the dialogue.

On behalf of the Institute and the Forum participants, I thank the Forum sponsors – ExxonMobil, Aramco Services Company, The Chrysler Foundation, ConocoPhillips, and Toyota – for their financial support. Without their generosity and commitment to our work, the Forum could not have taken place.

I also thank Leonard Coburn, who served as rapporteur. His extensive knowledge of energy enabled him to understand and capture the highlights of a wide-ranging discussion in this summary report. The dedicated efforts of Timothy Olson, whose efficient handling of the administrative arrangements once again contributed to a pleasant and smoothly run Forum, are also gratefully acknowledged.

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, opinions were often not unanimous and participants were not asked to agree to the wording.

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Oil and Gas in a Changing World

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Oil and Gas in a Changing World

A dramatic economic downturn and extreme price volatility in energy markets characterized the past year. Unprecedented price fluctuations led to investor uncertainty. This price instability made it difficult for policy makers to determine optimal economic, energy, environmental, and transportation policies.

Oil prices gyrated, rising to $147.50 per barrel in July 2008, falling 75 percent to $35.00 per barrel in December 2008, and then doubling to $70.00 by July 2009. Natural gas prices were similarly volatile. The economic downturn led to reduced demand for crude oil and natural gas — a dramatic change from the high-price, high-growth scenarios discussed at the 2008 Global Energy Forum.

Expectations are that after 2010 global oil demand will increase in emerging markets but not in developed countries. Whether supply will keep up with demand is an open question. The economic turndown led to oil demand destruction, and many oil development projects were deferred. In the next five years, robust oil demand and reduced supplies could lead to the next volatile oil price cycle.

Volatile prices and uncertain demand raise questions about the willingness of OPEC to make the necessary investments. Access to oil reserves is another serious issue, and above-ground geopolitical and financial issues as much as the adequacy of reserves make additional production difficult and uncertain.

A different way to affect the price of oil is to demand less. More fuel-efficient cars and alternative fuels hold great promise, but their rate of market penetration may not be adequate to offset the near-term impact of uncertain oil supplies.

A bright spot in the American picture is natural gas, thanks to the dramatically increased development of gas from shale. Recent high gas prices and technology developments in hydraulic fracturing and horizontal drilling led to an explosion in production and much higher reserve estimates, contributing to lower prices. Increased domestic supply and lower prices may lead to a greater use of natural gas as a bridge to non-carbon fuels in electric power generation.

Policy makers are struggling to decrease the use of oil and gasoline through a variety of costly but promising mandates — new CAFE standards, enhanced biofuels standards, stronger demand side efficiency standards, and possible new CO_2 emission limits. These changes could undermine the upward pressure on oil prices and lead to a future with less price volatility.

The impact of volatility in energy markets and the kind of economic recovery likely to take place will affect regional energy markets. Russian oil production is not likely to rebound beyond its 2007 peak of 10 million bpd. Central Asia and the Caucasus will experience strong production growth in the near future.

Future oil development in the Middle East will be cautious. Capacity additions are uncertain, although Saudi Arabia continues to increase capacity from 10 million barrels per day (bpd) to 12 million bpd. Oil and gas development in Latin America varies by country, with Brazil developing its offshore oil reserves, Colombia apparently back on track with increased oil production, and Mexico and Venezuela experiencing political problems that are undermining investment and reducing production, despite substantial resources.

The future of the U.S. automotive industry is as volatile as energy markets. In 2007, 16 million automobiles and light duty trucks were sold in the U.S. In 2008, only 9.5 million were sold. Two companies entered bankruptcy and emerged dramatically changed.

A multi-pronged policy approach is essential for the world and the U.S. to cope with problems associated with future economic and energy growth. A focus on supply or demand alone will be inadequate. Broader policies encompassing energy, environment and transportation are crucial for rational economic and political solutions.

I. The Economic and Energy Future

A. Economic Volatility, Global Recovery or a Lost Decade?

The worldwide scope of the financial crisis is unprecedented. Global production is still declining, but increasing consumer consumption, national and local spending increases, inventory rebuilding, renewed demand for industrial materials and growth in emerging markets are starting to signal expanded growth.

The downturn varied greatly among regions. In the U.S., real GDP fell by more than six percent in early 2009 followed by increasing levels of unemployment reaching 9.5 percent in July 2009. Western Europe's decline was even deeper. Most Western European countries are experiencing their deepest recessions of the postwar period due in part to banks' high leverage and exposure to Eastern Europe. Exports, often the mainstay of many Western European economies, and business investment are plunging. Home prices are falling. Recovery in Western Europe will be sluggish and uneven.

Emerging Europe faces staggering challenges due to the drying up of foreign borrowing that fueled past expansions. Social and political unrest is a reality as citizens take to the streets in protest over lack of jobs and stringent new government measures.

Asia is not immune to the global economic turmoil. China, India and Indonesia are growing at lower levels than 2008, while the rest of Asia is in recession. While finances are strong for most Asian coun-

tries, export dependence remains a serious problem. Government stimulus packages were used to substitute for export growth. Due to their success, Asia is leading the world's recovery. While Western Europe and North America had larger GDPs in 2008, Asia will be the world's top producer by 2018. The American consumer, the major economic force leading past recoveries, will not lead this recovery due to a retrenchment of spending to rebalance household accounts.

Of three scenarios for world growth, the most optimistic is "global recovery," reaching 4 percent real GDP growth by 2012 and then flattening out through the rest of the decade. A second scenario is "lost decade," with real GDP growth reaching only 2.5 percent by 2014 and declining to 2 percent or less through 2020. The last scenario is "volatile future," with real GDP fluctuating between 5 percent and 1.5 percent for the decade.

B. Energy Volatility — Too Much of a Good Thing?

The recession led to a decline of global oil demand by 2.5 to 3 million barrels per day from 2007 to 2008. Through the early months of 2009, oil demand was still falling, although the pace of the decline was starting to slow.

For 2010 and beyond, demand growth is very dependent upon the pace of the economic recovery. Demand in emerging markets will continue to grow; however, there will be little or no early growth in developed countries.

Assuming crude oil demand will rebound, a critical unknown is the medium-term supply response. Volatile prices, demand destruction and high production costs since 2004 led to significant project deferrals — up to 7.6 million barrels per day are at risk over the next five years. Robust oil demand recovery along with reduced supplies could lead to another upward oil price spiral. Demand may increase by 25 percent over the next twenty years, from 84 to 104 million barrels per day, based on the 2008 World Energy Outlook of the International Energy Agency (IEA). Where will the additional supply come from? Non-OPEC conventional oil supplies are peaking and

will decline in the future. Worldwide unconventional oil production and natural gas liquids will continue to increase. Conventional oil production expansion will have to come from OPEC. Will Saudi Arabia and other OPEC members such as Iraq and Iran expand their production?

Normal oil field depletion rates average 4.5 percent per year. In 2007, production totaled 70.2 million bpd; by 2030, applying this depletion rate, existing production will decline to 30.2 million bpd. To meet the 103.8 million bpd of demand expected by 2030, new oil production capacity of 45 million bpd will be needed. (Natural gas liquids and non-conventional oil are projected to supply 28.6 million bpd.) The required new crude oil production capacity is 43 percent of projected 2030 oil supply — a serious supply challenge.

International oil companies (IOCs) have full access to only seven percent of oil and gas reserves; national oil companies (NOCs) control 85 percent, of which 73 percent have no equity position. Russian companies control the remaining 8 percent. Of the top 25 oil and gas reserve holders, only six are IOCs, with a total of less than five percent of total oil reserves. The investment philosophies of the NOCs diverge sharply. Some countries such as Saudi Arabia are investing heavily for the future, relying on the best technology available and using the skills of the IOCs to their maximum advantage. Others, such as Mexico and Venezuela, actually are disinvesting. Both are diverting oil revenues to meet social needs without adequately reinvesting in their oil wealth to ensure an adequate future revenue stream.

By 2020 about 20 percent of U.S. supply is expected to come from Canadian oil sands and another 20 percent from the Middle East. If U.S. imports of oil from Canadian oil sands are limited due to concern about greenhouse gas (GHG) emissions (by some estimates GHG emissions from oil sands production are five times those from conventional oil), the consequences will be enormous. With about 25 percent of U.S refinery capacity geared to heavier crude oils, refiners are worried about shortages of these oils. If oil from oil sands is limited, what will replace it?

Another key driver of oil prices is global drilling costs. Over the last six years these costs more than doubled. While some of these costs are declining, they are not returning to 2004 levels. Some costs are cyclical, such as steel pipe. Others are structural, with more and more oil reserve replacements coming from more difficult reserves. Higher prices are required to develop these reserves. This leads to the question of the longer term direction of oil prices. If oil sands are the highest cost production, then they should set the long run price of oil. Environmental concerns should be factored into the cost. This would justify an oil price in the range of $60 to $70 per barrel.

A resumption of volatile and ever-increasing prices is likely. In the near term, oil market fundamentals are weak: declining demand, high inventory, and high OPEC spare capacity. For the medium term, reduced supplies caused by less investment may set the stage for the next upward price cycle. For the long term, the oil balance is likely to tighten due to strong emerging market demand growth, rising depletion rates for existing production, constrained resource access, and a shift to higher costs.

C. The Role of Futures Markets

Futures markets play an important role in price determination since many supply contracts are linked to futures prices. Some have argued that speculation has been an important element in higher energy prices. Others have found that speculators play an important role in counter-trades but have not influenced the price significantly. One way to test this argument is through an analysis of how futures markets work and who participates.

Participation in futures markets by investors rather than oil industry participants goes back to the 1980s, when oil prices plunged to $10 per barrel. Many investors realized that oil as a commodity could be a good investment and bought futures contracts. The year 2000 was viewed by many as the start of the commodity bull market – a strong rise in the level of activity and the entry of different types of participants. Previously financial firms, funds, and investors were

responsible for only about one quarter of activity — known as open interest. By 2006 this grew to more than half of the open interest. This is evidence that the futures market no longer was viewed only as a way to hedge against price volatility, but could be used as an investment vehicle where price volatility was necessary for investors to earn a return. The financials, funds and investors decided to invest directly in the commodity rather than invest in oil companies.

This strategy was increasingly adopted as oil prices strengthened and reached their peak in July 2008. On one exchange, open interest more than doubled from 2005 to July 2008. As prices peaked, open interest peaked and started its rapid decline, but not as sharply as oil prices. While oil prices plunged about 75 percent, open interest fell only 21 percent and then rebounded. Based on the open interest level and activity, a $60 price for oil looks more realistic than either the high of $147 or the low of $35. The lack of any significant difference in the identity of commercial and non-commercial participants led futures markets observers to conclude that speculation was not responsible for the rapid movements in oil prices.

D. Energy Efficiency — Changing the Energy Future

Oil prices are likely to increase due to supply constraints and growing demand, but there are ways to slow demand. To achieve significant reductions through energy efficiency, the U.S. will have to overcome several market failures and market barriers. One is the failure to take into account externalities — the costs of using the fuel that are not reflected in its price. Pollution is a primary example. Proposed actions to price CO_2 emissions may change this. The risk of price shocks due to disruptions in oil prices is another externality. While the U.S. government takes steps to reduce these risks, the costs are not reflected in the price of oil.

Another market failure derives from how consumers perceive their role. For example, a building owner is more likely than renters to install insulation, more efficient windows or appliances, programmable thermostats or low-flow showerheads. Both the owner and the

renter are engaging in rational economic behavior, but the result for the energy use and GHG emissions is quite different.

There is little understanding of how consumers view energy use or how to implement more fuel efficient technology even if it is offered. A consumer seeking a car has a large array of choices. Most consumers consider design, power, cost, and safety well before fuel economy or other operating costs such as regular or premium fuel. As a result, there is little consumer demand more fuel efficient cars today.

Another option for oil demand reduction is the electrification of vehicles. Transportation relies on oil for about 96 percent of its fuel, and about two thirds of all oil used in the U.S. is for transportation. To achieve major reductions in this oil use by electrification, the U.S. would have to shift to plug-in hybrids or electric only vehicles in a significant way. The fuel used to generate the electricity matters in terms of CO_2 emissions.

A recent study by The National Academies on another fuel-switching option estimated that by 2035 about twenty-five percent of gasoline can be replaced by liquid fuels from biomass. About 700 million tons of dry waste per year (corn stover, grasses, and other biomass waste) can be accumulated in the U.S. for conversion into liquid fuel. In 2035, about 1.7 million barrels per day of cellulosic ethanol could be produced if oil were between $60 and $100 per barrel. At that price, about 2.3 million barrels per day of cellulosic and corn ethanol together could be produced. If a mixture of coal and biomass were used to produce liquids, a total of about 2.5 million barrels of biomass liquids per day, or one quarter of U.S. gasoline consumption, could be produced. These fuels would compete with each other, and the estimates are not additive. In no situation, the study concludes, could one half of gasoline consumption be produced from biomass, as some proponents have estimated. Other options, such as the production of biofuels from algae, which is not yet commercially viable, hold promise, and public policy must be careful not to pick winners prematurely.

II. U.S. Policy Choices

A. U.S. Energy Policy — A History of Unfulfilled Promises

Beginning with President Richard Nixon, U.S. energy policy focused on reducing American vulnerability to foreign oil suppliers. The goal of Nixon's 1973 "Project Independence" was energy self-sufficiency by 1980. President Gerald Ford, succeeding Nixon in 1973, continued with the goal of oil self-sufficiency. Their plan posited that the U.S. could become a net exporter of oil by 1985 if federal onshore and offshore oil resources were developed.

President Jimmy Carter vowed that starting in 1979 America would never import more oil than it did in 1977 and that by the end of the 1980s the U.S. would cut its reliance on foreign oil by one-half. The Carter plan assumed that the world was running out of oil and that the U.S. must rely more on conservation, efficiency, and renewable energy.

President Ronald Reagan's first official act as President in 1981 was to sign an Executive Order eliminating oil price and allocation controls, which began in the Nixon era, were continued by Ford, and were set on a path for elimination by Carter. This action rationalized the U.S. oil market, releasing pent up demand for development of U.S. resources. Oil prices peaked in 1981 and continued to decrease throughout the 1980s. Reagan's strategy was to rely more heavily on the market than on government actions, reducing or eliminat-

ing many synthetic fuels, conservation and renewable energy programs. He reversed the Powerplant and Industrial Fuel Use Act that had limited the use of natural gas and began to fill the Strategic Petroleum Reserve (established under President Nixon) to protect against oil market disruptions. Reacting to $10 oil prices in 1986, Reagan issued a new energy plan focused on enhancing "Energy Security" by expanding domestic oil production.

President George H. W. Bush continued many of the Reagan era policies; however, the Comprehensive Energy Policy Act of 1992 also addressed many issues in the electric power industry and established an alternate fuels program for vehicles. The Clean Air Act (CAA) Amendments of 1990 increased regulation on stationary air polluters to reduce smog and instituted the first federal cap and trade system to reduce sulfur dioxide emissions causing acid rain.

President William J. Clinton's energy policy focused largely on efficiency standards and renewable energy. They also had a strong environmental component — the Kyoto climate change treaty was signed but not ratified during the Clinton years.

Under President George W. Bush, energy policy reverted to more reliance on market mechanisms. Two major energy bills were enacted during his administration. The Renewable Fuel Standard (RFS) passed in 2005 required the use of 4 billion gallons of ethanol in gasoline in 2006, increasing to 7.5 billion by 2012, or about 4.5 percent of gasoline consumption. The bill also introduced tax incentives for more fuel efficient vehicles and removed some restrictions on domestic oil and gas drilling.

In 2007 overall CAFE standards were raised for the first time since the 1970s. The fleet-wide standard — for cars and light duty trucks — was increased to 35 miles per gallon (mpg) by 2020. The RFS was increased to 36 billion gallons per year by 2022, with increasing use of cellulosic ethanol from 2013 onward. Incentives were provided for hybrid and plug-in hybrid vehicles.

Despite 25 years of policies aimed at increasing domestic production and reducing consumption and imports, consumption of

oil increased (from 17.3 million bpd in 1973 to 19.8 million bpd in 2008), domestic production decreased (from 10.9 million bpd in 1973 to 7.5 million bpd in 2008), and imports increased (from 6.4 million bpd in 1973 to 12.3 million bpd in 2008). A bright spot has been the decline in energy intensity. In large part as a result of higher energy prices, the U.S. now uses less than one half of the energy it used in 1980 to produce a unit of GDP.

During this period U.S. energy policy was heavily influenced by national security and economic considerations. Today reducing CO_2 emissions is as important an objective of energy policy as national security. Policies developed to fight global warming through improved fuel efficiency and alternative renewable energy sources also will enhance national security by reducing oil consumption and oil imports.

President Barack Obama has proposed to re-order U.S. energy priorities, with climate change, energy efficiency, renewable energy and advanced vehicle technologies receiving greater emphasis than oil and gas production. Energy policies are important to his environmental concerns since they can change how we produce and consume energy and move the nation towards a clean energy economy. There is renewed focus on energy efficiency standards and renewable energy, and a strong effort to reduce liquid fuel use in transportation through higher CAFE requirements and electrification of vehicles.

B. The U.S. and Climate Change — Policy and Politics

The centerpiece of President Obama's energy and environmental plan is cap and trade legislation. Stationary-source industries would buy permits to emit CO_2 — permits would be auctioned off and tradable. The auction would provide billions for government to compensate low income consumers, allocate money for renewable energy, fund energy R&D, or other purposes.

The initial strategy in the House of Representatives was to amass enough votes from the majority Democrats and bring along enough Republicans to pass the legislation. Negotiations in the Energy and

Commerce Committee focused largely on winning the support of Members from states with coal-burning utilities and smokestack industries. The Waxman/Markey bill passed by the Committee alters the Obama goals by seeking a 17 percent reduction of CO_2 emissions by 2020 rather than 20 percent. It also changes the cost allocation by initially giving away 85 percent of the emissions permits in order to reduce the price impact on certain hard-hit industries or their consumers. The bill would also mandate a 15 percent renewable portfolio standard in 2020, down from 20 percent in the Obama plan. Gas industry representatives argue that the bill does not take into account the recently recognized abundance of domestic natural gas, prolonging the life of coal plants despite the fact that gas emits 50 percent less CO_2 than coal.

There were also concessions to farm state Members. Farm interests wanted the Department of Agriculture (USDA) rather than the Environmental Protection Agency (EPA) to have jurisdiction over the program allowing an emitter to invest in domestic agricultural projects to "offset" CO_2. USDA was viewed as more likely than EPA to approve these offsets.

One of the major concerns about the bill is the provision of 1.5 billion tons of international offsets. These offsets could account for up to 25 percent of total U.S. emissions of six billion tons per year. Not only are there questions about whether such offsets would be verifiable, good projects are scarce. The European Union has not come close to using 1.5 billion tons of international offsets over an entire decade. While environmental and other groups wanted a hard cap on emissions, others saw the use of offsets as a way to add flexibility. The bill's sponsors made the concessions to move the legislation along.

While many observers view the bill as too weak, it would mark the first serious federal government effort to tackle climate change. It also may be the limit of what is currently politically possible, and many observers expect the Senate to weaken the bill further. Others note that whatever is achieved, it is likely to be only the first effort, with successive efforts imposing more stringent targets that are more difficult to achieve.

Some opponents of a cap-and-trade approach prefer a carbon tax. Like cap and trade, a carbon tax placed on CO_2 emissions can achieve specific emission reduction goals if adjusted periodically. It can be administratively efficient by focusing on larger stationary facilities that emit GHG. Many think that a carbon tax is more predictable and its costs more transparent. Like the auction revenues under cap and trade, the tax revenue can be used to reduce the burden on heavily impacted consumers, returned to the economy by reduction in other taxes, used for incentives for new technology, or applied to deficit reduction. Similarly, tax credits can be used for offset projects and can more easily be made to comply with world trade rules. A major political drawback of the carbon tax is the use of the word "tax." Perhaps the euphemism "refundable emissions fee" might placate these concerns.

C. The Ethanol Mandate — It's Not Easy Being Green

The 2005 and 2007 energy legislation introduced and expanded the requirement to use ethanol as a substitute for petroleum transportation fuels. The mandates were actively supported by the corn producers, since almost all ethanol today is made from corn, but actively resisted by the oil industry. Ethanol today represents about 7.2 percent of gasoline supply. The legislative mandate requires 36 billion gallons to be produced in 2022, which will comprise about 25 percent of gasoline supplies

Currently most ethanol is blended with gasoline at a 10 percent ethanol-90 percent gasoline ratio or less. The 10 percent ethanol limit is called the "blend wall." Today's vehicles are built to accommodate this limit. Flex-fuel vehicles are produced that can use E-85 — 85 percent ethanol and 15 percent gasoline — but fewer than 2,000 of the more than 100,000 service stations sell E-85. When the ethanol mandates were enacted, it was assumed that up to 15 billion gallons of ethanol per year could be accommodated easily with stable gasoline demand. With the increase in gasoline prices between 2004 and 2008, the higher costs associated with using more ethanol easily could be included in the price of gasoline. But gasoline demand fell in the latter

half of 2008 and is continuing to fall in 2009. The RFS is volumetric, not a percentage of the gasoline supply. As demand drops and ethanol production increases, more ethanol is available than can be blended. Also, with gasoline prices falling and ethanol production costs remaining relatively high, the RFS poses economic costs on refiners.

What happens to ethanol production once the blend wall limit is reached? Will marketers increase their production of E-85? Will more stations put in E-85 pumps? Will manufacturers produce more flex-fuel vehicles? Will they cover ethanol blends of more than 10 percent under their warranties, or modify their vehicles to accommodate higher blend ratios?

These and other policy questions raised in this section are critical to the long-term success of the American economy. There is some opinion today that the current policy making process is dysfunctional. In the Executive Branch there are thirteen agencies with some authority over energy. In Congress twenty-six committees and subcommittees have some jurisdiction. Moreover, the time horizons of the political process and industry differ substantially. The oil and gas industry plans for 10 to 35 years or more. The political time horizon is often two to six years. This mismatch can result in policy changes that can jeopardize long-term investments. Solving the problems of energy policy making also requires dramatic changes in consumer behavior. There are serious deficiencies with education and information that must be overcome if the nation is to move forward in a progressive and productive manner.

A suggestion was made to remove energy policy making from the political process as much as possible. The Federal Reserve was discussed as one model. An independent agency could be created with a Board of Governors that can act on a long-term basis. Experts would staff the agency with a mandate to act in the best interests of the nation. Another suggestion was to use something similar to the military base closing commission, where the recommendations must be voted on without amendment. But there was a general feeling that dramatic change would be difficult, and that the American system of democracy was better than any other system, despite all of its failings.

III. Natural Gas — New Resources and New Thinking

A. Natural Gas — Missing an Opportunity

U.S. production of gas from shale has increased rapidly in recent years. Increasing production is occurring through direct investment by the industry, without any new government incentives or new access to federal lands.

Over a 10-year period, production in the Barnett shale gas basin in and around Fort Worth, Texas increased over 3,000 percent, from 94 million to about 3.5 billion cubic feet per day (Bcfd). Other fields, such as Fayetteville in Louisiana, Haynesville in Louisiana and Texas, and Arkoma Woodford in Texas and Oklahoma, are all showing similar signs of increased production. Marcellus basin, in West Virginia, Pennsylvania and New York, is expected to be next. All the basins in the lower 48 states are located under or near major gas pipelines, leading to lower development costs.

Between 2006 and 2009, U.S. natural gas resource estimates increased significantly, primarily due to increased availability of economic shale gas resources.

Better technology allows economic production of a vastly greater resource base. Improved hydraulic fracturing techniques and greatly improved horizontal drilling allow tight, geographically diffuse reserves to be developed. Producers estimate the top seven basins will

Figure 1

U.S. Natural Gas Resource Estimates

Year	Total	Shale Gas	Years of production
2006	1,530 Tcf	137 Tcf	82
2009	2,074 Tcf	616 Tcf	100+
% change	35 %	350 %	

Source: Potential Gas Committee, *Potential Supply of Natural Gas in the United States, June 2009*

Between 2006 and 2009, U.S. natural gas resource estimates increased significantly, primarily due to increased availability of economic shale gas resources.

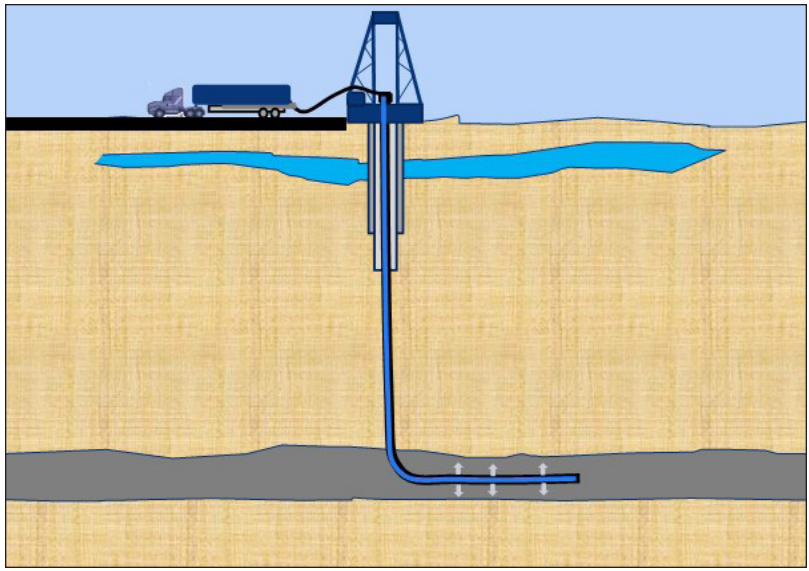
produce from 27 to 39 Bcfd upon full development. Thanks largely to the enhanced expectations for shale gas, domestic natural gas production is estimated to grow from about 55 to close to 90 Bcfd, a growth of 35 Bcfd, the energy equivalent of 42 percent of expected vehicle fuel use or 50 percent of electricity generation from coal in 2030.

Strong demand with a stable price in the $6-7 per thousand cubic feet (Mcf) range is necessary for continued shale gas development. A critical issue confronting the industry is the ability to continue using hydraulic fracturing. The tight formations require fracturing to allow the gas to flow (See Figure 2), and some concerns have been raised about high-pressure fracturing. The concerns focus on polluting underground aquifers because the liquids used to fracture the rock could seep through the cracked rock and cause contamination. Producers and other experts are confident, however, that careful development and existing regulation can prevent harm.

Analysis of U.S. natural gas must consider liquid natural gas (LNG). The focus of discussion nationally shifted as the domestic LNG industry matured from the need for permits for new gasification facilities in the U.S. to how the gas market functions and whether price manipulation occurs. So far the price for LNG in the U.S. is within an acceptable range and is competitive, undermining arguments about price manipulation.

Figure 2

Production of Gas from Shale



Source: Navigant Consulting Inc. 2009

Hydraulic fracturing and horizontal drilling release natural gas from tight formations found far below drinking water aquifers.

Global LNG prices are more volatile because they are reacting to too much or too little supply. Also, where LNG and natural gas prices are linked to oil prices, they followed oil's recent volatility. In 2009, world natural gas prices settled to less than $5 per million BTU (1 million BTU ≈ 1 Mcf). The problem for most gas markets is that with weak and uneven economic growth and weak oil demand, it is difficult to discern a price pattern.

Natural gas prices, however, behave differently in different regions. In Asia, where gas demand overall was only 27 Bcfd in 2007, high prices in Japan, South Korea and Taiwan led to more efforts to control demand growth. China is seeking new supplies and is building a new pipeline to connect with natural gas rich Central Asia. These efforts are having some success in altering supply and demand patterns. Prices in Asia are still linked to oil prices; however, the reliance

on more pipeline gas eventually may lead to a decoupling from oil.

In Europe 90 percent of natural gas is delivered by pipeline. More LNG import capacity is being built to lessen dependence upon pipeline gas. LNG capacity will almost double by 2010 (from 10 Bcfd to 19 Bcfd), while pipeline delivery capacity will increase only ten percent (29 Bcfd to 32 Bcfd). This additional capacity is necessary since any new supplies will have to be imported. Domestic production is stagnant — 28 Bcfd in 2007 vs. 29 Bcfd in 2010. By 2020 and after, a substantial amount of new pipeline capacity is being planned from Russia, from North Africa and from the Caspian/Middle East. The Nabucco Pipeline delivering gas from Iraq, Azerbaijan and Central Asia is viewed as an alternative to natural gas from Russia.

Natural gas flows from Algeria and Norway continue without disruption. Russia is bearing the brunt of the decline in demand due to its high prices and European fear of over-dependence on Russia. In 2010, Asia/Pacific LNG production of 13 Bcfd will continue and be supplemented by 3 Bcfd from the Middle East/Gulf region. European LNG demand of 6 Bcfd will be met from Middle East/Gulf, Africa and Caribbean production. This leaves about 11 Bcfd of LNG production for the Atlantic basin that could move into North America or Europe depending upon prices.

In North America, LNG import capacity will increase from 5.0 Bcfd in 2007 to 16.8 Bcfd by 2010. Too much capacity will be available; only about 33 to 45 percent of it will be utilized in 2010. Since there is a strong incentive to maintain natural gas production due to the large sunk capital costs in the LNG chain and strong prices for natural gas liquids, gas in the Atlantic will be plentiful and subject to arbitrage. It will go to the market with the greatest incentive to buy the gas for storage and eventual consumption. In this arbitrage market, North America, with its relatively abundant storage capacity, will play a critical role.

How much LNG can the North American market absorb? Will LNG become an important part of the U.S. energy mix, especially in light of the dramatic increase in shale gas production? Will it be

part of the base load or will it be the marginal gas supply? Will it hold the price of natural gas down and limit the production of gas from shale?

Answers depend on the price of natural gas in the U.S. If natural gas is at $6-7 per Mcf, everyone will produce natural gas and LNG will be competitive. If the price is lower, then it will be difficult to sort out the role for LNG and shale gas. Abundant LNG will be produced, but whether it will come to North America will depend on prices in North America relative to Asia and Europe.

Another question for the LNG market is where new large capacity will come from in the next twenty years? Will Russia and Iran become major LNG producers in the future? Iran is looking at LNG, but its internal problems overwhelm any effort to develop an LNG industry. Russia is just entering the LNG market; however, its focus still is on pipelines.

B. Climate Policy — Gas Is Missing from the Solution

With such high levels of natural gas resources, what role will gas play once the U.S. imposes a price on CO_2 emissions? Historically, cheap and plentiful coal dominated U.S. electric power generation. In the 1970s nuclear became a fuel of choice for new capacity additions as the nation diversified its generation mix. Since 1999, more natural gas capacity has been added than any other fuel due to its abundance and capital cost advantage. More recently some renewable energy entered the mix.

Even before the 2008-09 recession, electricity demand growth was slowing. Based on Energy Information Administration (EIA) projections, which do not assume future policy changes, it will continue to do so. From 2000 to 2007 electricity demand grew at 1.1 percent per year. The projections for growth to 2030 are even lower — 0.9 percent per year. Expectations are that by 2030 generation capacity will be only 25 percent above today's levels.

The EIA projects that the mix in fuels will change substantially between now and 2030. Coal will continue to fall from its high of 58 percent of total generation to under 45 percent. Natural gas will increase its share to about 20 percent. Renewable energy, primarily wind and biomass, will have the strongest growth, from 8 percent of today's generation (including hydro) to 16 percent in 2030. Renewables will meet 44 percent of total electricity generation growth between now and 2030. Nuclear will add some new generation, but its total share will decline a little to less than 20 percent of total capacity.

In a study that does anticipate climate policy changes, the EIA projects that fuel choice will play out differently in three different competitive arenas: old versus old facilities, new versus new, and old versus new. The four key factors that will determine the outcome of these competitions are capital costs, fuel costs, climate policies, and wild cards.

The capital costs of all energy projects increased significantly over the last three years. New coal and nuclear capital costs increased the fastest. Higher capital costs favor existing plants and less capital-intensive new plants. In fuel costs, natural gas prices increased much faster than coal prices, increasing interest in other technologies. Placing a value on CO_2 will raise the price for all fossil fuels. Coal will be the most heavily affected; natural gas will be affected much less.

In the competition among fuels, a levelized cost analysis (capital and operating costs) indicates that it would take a much higher value on CO_2 to discourage running an existing coal-fired plant than to discourage the construction of a new one. With natural gas prices of $5 per Mcf or less, however, no matter what the CO_2 value is, new natural gas plants are always more cost effective than either new or old coal plants. New renewable energy or nuclear plants would be more desirable than new or old coal plants with CO_2 values of $20 per ton or more. CO_2 values would have to increase to $50-60 per ton before new renewable energy and nuclear plants would be more desirable than new or old natural gas plants with natural gas prices

between $5 and $13 per Mcf. The wild cards are potential policy developments such as the elimination of subsidies for renewable energy or problems in licensing and building new nuclear power plants.

This analysis indicates that in all scenarios one impact of climate change legislation on the future mix of electric power will be less coal used in 2030. The level of reductions will depend upon the rigor of the policies. Renewable technologies, especially biomass and wind, will increase in all scenarios. Biomass is particularly important, starting out with co-firing and then shifting to dedicated plants using energy crops. Natural gas use is important but will become much more so if nuclear, biomass and carbon capture and storage all run into trouble. If the introduction of these options is constrained, electricity prices will be higher, overall demand will decline, and natural gas use will accelerate.

IV. Regional Issues

A. Russia in the Doldrums; Central Asia Rising

Russia's oil production increased steadily from 2000 and reached its peak in October 2007, with production slightly over 9.9 million bpd. Since then its production trended down for most of 2008 into 2009. The growth was due to a change in the political and economic environment with the election of President Putin in 2000 and to the use of western technology to improve the management of old West Siberian oil fields. Production declined as Russia's and the world's economy turned sharply downward in 2008.

The 2008 dip raised alarms throughout the world as many saw it as the start of a long-term trend. A closer examination revealed that Russia's tax environment was undermining all incentives to produce more oil. The combination of the mineral extraction tax and the export duty along with the profit tax was taking more than 90 percent of the marginal revenue generated by exporting crude oil. The export duty was based on the oil price two months earlier. Since oil prices were falling precipitously, exporters actually were losing money by producing and exporting oil. Production was shut in. Later in 2008, the government altered the calculation of the duty to look back only one month, making exports marginally profitable once again. Despite these changes, production continued falling.

Falling production now was the result of lower capital investments, which declined by 30 to 50 percent as the Russian GDP fell by double digits. By mid 2009 production started to increase again, mostly because production costs denominated in rubles fell as a result of ruble depreciation.

Major problems remain in West Siberia as the old fields rapidly decline despite new technology. The resurgence in production is coming from new areas, such as Timan Pechora in the north or in East Siberia. These new fields and the Sakhalin fields will be the future success story for Russia.

Forecasts for Russian production show a small increase to about 10 million bpd, but the large number of variables (economic recovery, taxation, infrastructure development, oil prices, export demand) suggest it could go either way. There certainly is no political will to push Russian production beyond 10 million bpd, since the Russian government does not want to see oil prices collapse with too much supply.

In Russia, politics and economics are even more closely linked than in other countries. Both rely on oil and natural gas production and prices. The majority of Russia's budget revenues and foreign exchange earnings come from oil and natural gas. At least two thirds of Gazprom's revenues and earnings come from the sale of natural gas to Europe. Most of Russia's oil markets are in Europe. Russia needs both European and Chinese markets to sustain its economy and future growth.

Russia also worries about becoming too dependent upon China for revenues from oil and gas. Russia still has border conflicts with China, has concerns about too many Chinese settling in East Siberia, and worries that its army is relatively weak compared to China's. Russia wants to use its energy as a way to dominate the Russian-Chinese relationship. China sees Russia as a major source of future energy but is not willing to cede power. After years of negotiations over pipeline natural gas deliveries, China still refuses to accept Russia's demands in pricing. Russia now is less interested in a natu-

ral gas OPEC since it was rebuffed in locating its headquarters in St. Petersburg. The location will be in Doha, Qatar.

In Azerbaijan, oil production continues to increase despite operational problems in its largest offshore oil field. Production is now in the range of 1 to 1.1 million bpd. Future prospects look positive until about 2020 as current offshore production expands, primarily through field extensions. Production will peak at about 1.3 million bpd in 2020 and then start a decline to about half that level by about 2030. Azerbaijan's biggest discoveries will be in natural gas. As new natural gas pipeline capacity is built, production will expand.

Kazakhstan's oil production steadily increased to about 1.5 million bpd by mid-2009. Its potentially largest discovery, Kashagan in the northern Caspian Sea, has huge development problems. The oil has up to 18 percent hydrogen sulfide and is under high pressure, meaning that special equipment will be needed to produce the oil and eliminate the deadly hydrogen sulfide. Also, Kashagan is in an environmentally protected area due to sturgeon spawning.

Kazakhstan's export potential is much larger than its current capacity. Its export problems will occur in 2011-12 because of capacity limitations in the Caspian Pipeline Consortium (CPC) pipeline that delivers crude oil from the Tengiz field through Russia to the Black Sea. After years of negotiations Russia is now willing to allow its expansion, permitting more oil exports. In addition, other export options will be available, including more pipeline capacity to China and increased cross-Caspian barge shipments to feed the Baku-Tbilisi-Ceyhan oil pipeline. Kazakhstan will need all of these options as its exports could exceed 2.5 million bpd by 2025. Reliance on Russian routes will still be at 58-60 percent of total exports, so Kazakhstan will need to tread carefully among Russia, China and the west.

B. China's Search for Energy

Several estimates indicate that China's oil demand will more than double by 2030. Its natural gas demand is likely to triple. The economic crisis and lower prices created favorable conditions for China

to secure energy supplies for the long term. With so many companies having financial difficulties, there is less competition for assets, and China's state controlled NOCs are not cash constrained. The three largest banks in the world based on asset value are Chinese, and Chinese banks are willing and able to provide financing for acquisitions.

China's banks instituted a series of loans-for-oil deals whereby the banks loan money to foreign companies and obtain access to oil in return. Figure 3 indicates the most recent deals and the players involved. In these situations, China acquired oil or natural gas by loaning money to the foreign company or bank. Except with Kazakhstan, these deals are not tied to upstream acquisitions of assets, just to the purchase of oil. This differs from the past Chinese practice of building infrastructure (railroads, for example) in order to acquire oil assets. China hopes that these loans-for-oil deals eventually will lead to enhanced opportunities for asset acquisitions.

Figure 3

Chinese International Loans-for-Oil Deals

Country	Lender	Borrower	Amount
Russia	CDB	Rosneft	$15 billion
Russia	CDB	Transneft	$10 billion
Kazakhstan	CEIB	KDB	$5 billion
Kazakhstan	CNPC	Kazmunaigaz	$5 billion
Brazil	CDB	Petrobras	$10 billion
Venezuela	CDB	Bandes	Not finalized
Turkmenistan	PTR	PetroEcuador	$1 billion

CDB = China Development Bank
CEIB = China Export Import Bank
KDB = Kazakhstan Development Bank
PTR = PetroEcuador

Source: Erica Downs, The Brookings Institution

The loan-for-oil deal most important to China is the loan to Transneft for building the spur line from the Eastern Siberian Pacific Ocean (ESPO) pipeline to China. Without this loan, as well as the loan to state-owned Rosneft for a twenty-three year oil supply deal, it was unlikely that the Chinese spur line would be built.

The loan-for-gas deal with Turkmenistan is likely to be the most geopolitically significant. China National Petroleum Company (CNPC) made a deal with Turkmenistan's natural gas company to help develop the South Yolotan field, considered one of the largest onshore natural gas fields in the world. The Turkmen are looking to foreign investors for expert assistance to develop this field, which is very deep, very high pressure and very high in hydrogen sulfide. The Turkmenistan-China pipeline provides Turkmenistan with an outlet for its natural gas, including South Yolotan, that does not go through Russia and will erode Russia's influence and dominance of Turkmenistan's gas. Turkmenistan could be among the world's largest exporters of gas in ten years. Most of this production will be going to the east, not the west. The first of the Chinese pipelines will be completed by early 2010. A decision on the second, parallel pipeline will be made in the future.

Separate from these loans-for-oil deals are the merger and acquisition activities of Chinese NOCs, including CNOOC's LNG deals in Australia. All Chinese NOCs are active in Iran, while CNPC is looking downstream at refinery acquisitions.

C. The Middle East – A Changing Role in a New Energy Balance

The Middle East has huge hydrocarbon resources with little or no pipeline access by the west, except for Iraq. There is a high degree of political uncertainty in the region, but it has always been a reliable oil and natural gas supplier. An expansive suggestion was made indicating the majority of world's petroleum resources are found in a corridor starting in Saudi Arabia and going through the Caspian region, Siberia, and ending in Canada. Resources from this corridor

flow to the closest geographic market — China is very close to this corridor. China has an interest in the corridor's resources, including Alberta, where China is investigating the idea of an oil pipeline from Alberta to Canada's west coast.

Many think that the real future of Iraqi petroleum development is in natural gas. The Nabucco Pipeline is looking to the Middle East as a source of gas. At the moment, no Turkmen gas is available. Iranian gas is not a likely source for political reasons. The Kurdish region of Iraq has huge potential. Two European Companies, OMV of Austria and MOL of Hungary, made deals with the Kurds to produce and export natural gas from 2015. These deals could be pivotal for Nabucco and for the European relationship with Russia. The unanswered question is the speed of development given all the political problems.

Iran has the second largest natural gas reserves in the world yet does not export any gas. Serious internal problems complicate its ability to complete projects with foreign companies. Many believe that there is not much of a future for gas exports. Its production is difficult, as difficult as its politics. If it does get produced and exported, it will go east rather than west due to cooperation with Pakistan and India over a new pipeline.

The Middle East could become a center for green power. The development of a green grid in Qatar is a possibility. Saudi Arabia also is interested in a green grid. There could be a good balance between wind at night and solar during the day. The problems with solar in Saudi Arabia are high temperature and sand. The sand is so fine that it can get into the solar panels and lower the efficiency of the panels.

D. Latin America — Large Potential, Missed Opportunities

The World Bank commissioned a study of Latin America in the 1990s with suggestions for improvements to their economies. The recommendations focused on improvements to governance, fiscal terms, international monetary reserves, labor reform, and exchange

markets. By 2000, many of the recommendations were carried out and the region looked much improved. Inflation was down, monetary reserve positions were better; labor problems were under control; overall governance was better. The test came in 2008 with variable results.

An oil and natural gas summit in 1994 in Miami created the Energy Initiative in Latin America that looked at barriers to energy integration on the continent. The dream coming from this summit was energy integration throughout Latin America. In the years since not much has happened to move closer to the dream.

The Latin America energy picture has its successes and its problems. Brazil is the most vibrant economy in Latin America and is a large producer of ethanol used for automotive fuel. It set a target for energy self-sufficiency, although its reliance on imported natural gas is making this goal elusive. It is developing its offshore with a strong investment model. Two huge new offshore oil fields recently were discovered. It has 11 billion barrels in oil reserves, but only 8.8 Tcf in natural gas resources. It imports about 1.5 Bcfd natural gas from Bolivia. Brazil's answer on natural gas is to import LNG from Africa.

Colombia is among the success stories. It was producing 900,000 bpd of oil in the mid 1980s. Then decline set in due to political issues and poor contracts with discouraging fiscal terms. It has large reserves: 1.6 billion barrels of oil and 4 Tcf of natural gas, with more than 80 percent of its basins still not explored. In recent years contracts were transformed, and the production decline was arrested. Its political troubles have lessened, and it now is producing 650,000 bpd and looking to 1 million bpd in the near future. Trinidad is another success with natural gas reserves of 26 Tcf and a large LNG facility. It is an important source of LNG for the U.S. and Europe.

The problem countries unfortunately outnumber the successes; Argentina has large natural gas resources and used to export gas to Chile and Brazil. The supply situation deteriorated when new contracts made new investment difficult. The natural gas price is frozen and tied to the old currency, and a new export tariff is preventing any exports. This situation remains unresolved.

Another problem country is Bolivia with natural gas resources of 54 Tcf. Its wells are very deep — 12-13,000 feet. President Evo Morales now says that all of the natural gas belongs to the government, but the government is not doing anything to support existing or new production. It is no longer producing enough natural gas to export to Argentina.

Several smaller countries have oil or gas reserves but are having difficulty attracting investors. Peru does not have much oil, perhaps 250 million barrels of reserves. But it has about 16 Tcf in natural gas reserves. At one point, Hunt Oil joined with an Argentine company to produce gas that now supplies Lima, but few new investors are interested due to political turmoil. Ecuador produces 500,000 bpd of oil and is exporting to the U.S. Because investors are leaving due to political problems, its future is not bright. Few western investors are interested in Cuba, which has small oil production. Most of its oil comes from Venezuela free of charge.

Mexico and Venezuela both have huge potential, but their turbulent political environments are leading to disinvestment and lower oil production. Mexico has large oil and natural gas reserves: 12 billion barrels of oil and 15 Tcf of natural gas. It used to have oil reserves of 27 billion barrels but has lost 1 billion barrels per year due to field depletion. Its production is now at 3 million bpd and continues to fall, although the trend could be arrested at 2 million bpd. For historical reasons, the rights to subsoil development were transferred to the central government. Constitutionally, development of these resources is limited to State-owned companies — today Petroléos Mexicana (Pemex). President Vincente Fox unsuccessfully tried to change the constitution to allow foreign company participation. More recently President Felipe Calderon tried to implement change and also failed. Mexico already imports gasoline and will soon start importing natural gas. No policy change is expected soon.

Venezuela also faces serious oil production issues. When President Hugo Chavez was elected ten years ago, he took on Petroléos de Venezuela (PDVSA) and fired 20,000 people, including most of the professionals. At that time PDVSA was producing 3.5 million bpd

of oil by relying on a large number of joint ventures with foreign participants totaling $35 billion in investment. The potential was there to reach 4.7 million barrels of oil per day. Today PDVSA produces 2 million bpd. Chavez uses oil as a political tool, providing 17 countries with free or subsidized oil. He uses revenues from PDVSA to carry out internal social programs and to spread his political philosophy throughout the region. PDVSA lost some international joint venture partners recently as Chavez arbitrarily ordered changes in the fiscal terms of the production contracts. Reinvestment is lagging, and production is likely to continue to fall. Chavez has promoted the idea of integrating the continent with a natural gas pipeline to Argentina, but the natural gas reserves do not exist to support such a pipeline.

V. Liquid Fuels for Transportation

A. Modern Transport Policy: Reframing the Issue

A discussion of oil markets is not complete without examining global transportation, which is 90 percent dependent on oil. The future of the automotive industry will largely determine how the world and the U.S. consume oil. Transportation policies can be used to alleviate congestion and simultaneously reduce CO_2 emissions. Fuel economy and technology improvements are important to solving the emissions problem; they are not the end of the story.

One view suggests that the U.S. transportation system is broken — there is no unified national policy to deal with transport problems — but the U.S. approach is to treat energy, climate change and transportation policies separately. Cities in emerging economies are even more seriously bogged down in congestion and pollution. In China, India and other countries, per capita CO_2 emissions are low but are increasing rapidly as more autos are bought due to rising affluence. New transport policies are important to dealing with congestion.

Significant progress can be made by shifting to other modes of transportation. Bus Rapid Transit (BRT) is one solution, using dedicated lanes to reduce travel times and emissions while alleviating congestion. These systems are operating in several congested cities including Mexico City and Jakarta. Truck transport is also very important globally. Better logistical planning can help by cutting down on empty

trips. Promoting inter-modal movements with rail can also help, as can improving truck efficiency. Unclogging congested rail centers is critical. In Chicago, cargo coming from the west destined for the east must be unloaded on the west side of the city, trucked to the east side and transferred again to rail to complete its journey.

The introduction of biofuels may have some impact, although all options are currently expensive. Making changes to vehicles can also lead to less oil consumption and lower CO_2 emissions, but factors such as population growth and increasing vehicle miles traveled could offset these gains.

Reframing the issue in terms of transport policy can help make the problem more manageable. A new policy could include vehicle-miles-traveled taxes and/or congestion pricing and internalizing transport, CO_2, and energy costs by imposing a $1 per gallon oil security fee. Shifting funding to BRT or other public transit could affect land use choices and foster the use of public transit, bicycles, and walking. Ending unproductive subsidies in energy, agriculture and transportation could generate substantial revenues to pay for these new programs and also provide funds for incentive programs.

B. A Challenge to the U.S. Auto Industry

The Obama Administration in March 2009 announced new fuel economy standards for cars and light duty trucks, bringing them in line with California's proposed standards. For cars, the new goal is to reach 39.5 mpg by 2016. Only one car company, Toyota, meets today's standard of 27.5 mpg. For light duty trucks the goal is to reach 30 mpg, up from today's 21.5 mpg. No U.S. automaker meets today's standard. The goal for 2016 is for the combined auto/light duty truck fleet to achieve an average 35 mpg, a 27 percent increase from today's 27.5 mpg.

U.S. industry has the technology today to meet increasing standards over the next two to three years. The industry has six years and two model changes in order to reach the 2016 standards. The

standards are achievable, but it will take many engineers and $50-100 billion for new equipment.

A multiple technology approach rather than any single solution will evolve to reach the 2016 standard. Vehicle technological changes include weight reduction, friction reduction, tire friction reduction, and better aerodynamics, transmissions, and valves. More advanced technology will be used on gasoline internal combustion engines and on diesel engines. Direct injection can use fewer cylinders to achieve similar power while increasing efficiency by twenty percent.

The move to gas-electric hybrids and all-electric vehicles will reduce gasoline use while offering different levels of CO_2 emission reductions. Gas-electric hybrids are likely to have lower CO_2 emissions than plug-in electric vehicles because the latter must include emissions from power generation in the overall calculation. If the electricity is generated from renewable energy or nuclear, plug-in electric vehicles are likely to have lower CO_2 emissions. Gas-electric hybrids also are cheaper and therefore are likely to be a more cost-effective solution.

From 1987 to 2007 fuel economy in the U.S. fleet declined by 2 percent while horsepower increased by 89 percent and weight increased by 29 percent. Technology improvements that could have been used to improve gas mileage moved the U.S. auto fleet in the wrong direction. With the new standards, technology over the next ten years will have to take the industry in the right direction, with fuel economy increasing by 45 percent, horsepower declining by 50 percent and weight declining by 30 percent. Without incorporating the recent changes in fuel economy standards, EIA projected that gasoline demand in the U.S. would remain flat even as liquid fuel use increases; these increases will be met by renewable fuels through at least 2020 and perhaps to 2030. An approach to lessen oil dependence should rely on a portfolio approach including biofuels, electrification, fuel economy standards, and technology. Changes in vehicle technology and efficiency can yield a saving of 4 million barrels per day by 2020 from what demand would otherwise have been,

while a change to biofuels could save another 2-2.5 million bpd. Together this would amount to about half of the automotive fuels currently used in the U.S. Electrification could take another big leap towards reducing the remaining gasoline use.

Natural gas vehicles (NGVs) are not included in the portfolio suggested because, while the technology is available to build these cars today, the infrastructure is lacking to supply them. There was a push for NGVs in the Energy Policy Act of 1992; however, the limited availability of refueling stations and the lack of a commitment to support the development of a refueling system doomed any government sponsored incentives. There may be a market for natural gas vehicles in trucks and buses, but these are likely to be limited to fleets that can be refueled at central facilities.

C. From Theory to Reality — What Cars Will People Buy?

Major changes occurred in the past year as U.S. auto sales plummeted from 16 to 9.5 million vehicles. To jump start sales, the U.S. government intervened. "Cash for Clunkers" to remove old cars and replace them with new, more fuel efficient ones began in late July 2009. Many thought that this program was too complicated, but post-Forum results show that it was very popular. Comprehensive cap-and-trade legislation currently being considered by Congress would also change the landscape for auto manufacturers. For the U.S. to reach the ultimate target of 80 percent GHG reductions by 2050, companies need to start making changes today.

These actual and proposed policies come on top of new biofuels and fuel economy standards. Automobile companies expect that technology improvements to gasoline internal combustion engines, plug-in hybrids and other gas-electric hybrid vehicles, electric vehicles, and hydrogen fuel cells will be necessary to make the required transitions.

Electric vehicles were first marketed in California in 1991 with sales of only 300 vehicles per year. To be sustainable, at least 100,000 vehicles need to be sold annually. The program failed due to many issues. All technological problems must be solved before introduction. The consumer and the market must be ready for acceptance. Regulatory policy must be aligned with both the available technology and consumer acceptance; consumers will not accept a new product unless it is better in every respect than what was used previously.

Building on their experience with gas-electric hybrids, some companies are moving towards plug-in hybrids, which have lower CO_2 emissions and increased fuel economy. The introduction of plug-in hybrids using lithium ion batteries presents many challenges including cost, durability, high and low temperature performance and energy density (range per charge). Companies also are looking at hydrogen fuel cells. It is conceivable that a hydrogen fuel cell automobile will be ready by 2015.

The path to meet increasingly strict fuel economy and emissions requirements is difficult. With twenty years required to replace the on-road capital stock, products sold today need to take into account requirements twenty years out. This sets an extremely high hurdle. It requires certainty in government policies. It demands an environment where companies can experiment with various technologies. And it necessitates maintaining an open attitude to avoid picking winner and losers too early.

Appendices

Agenda

Oil and Gas in a Changing World

Friday, June 26

8:30 – noon

SESSION I: The Economic and Energy Future

Economic growth, or lack thereof, will be a primary near-term factor in energy demand. Access to reserves and other above-ground constraints on production will influence supply, and futures trading can have a short-term influence on price. Innovation can have a large impact in the medium to long term. This session will discuss these factors and their influence on energy projections.

Economic growth forecast	**Sara Johnson,** Managing Director Global Macroeconomics IHS Global Insight
Oil and gas supply & demand forecast	**Marianne Kah**, Chief Economist, ConocoPhillips
The role of futures trading	**Albert Helmig**, President, Hong Kong Mercantile Exchange
The potential of energy efficiency	**James Sweeney**, Director, Precourt Energy Efficiency Center Stanford University

1:30 – 5:00 p.m.

SESSION II: U.S. Policy Choices

U.S. energy and environmental policies, including legislation on climate change, domestic oil and gas production, and promotion of biofuels, could affect energy supply and demand both within the United States and globally. The Forum will discuss some of these proposals, the prospects for their adoption by Congress, and their possible impacts.

Challenges of achieving Administration goals	**Herman Franssen**, President International Energy Associates
Prospects for Congressional action	**Jason Grumet**, President Bipartisan Policy Center
Pricing GHG emissions	**Sherri Stuewer**, Vice President, Environmental Policy and Planning, ExxonMobil
Scaling up biofuels	**Lucian Pugliaresi**, President Energy Policy Research Foundation (EPRINC)
Respondent	**John Hofmeister**, CEO Citizens for Affordable Energy

Saturday, June 27

8:30 – noon

SESSION III: Natural Gas

Is natural gas a fuel for long-term growth, or a bridge towards a no-carbon energy future? Two years ago this Forum heard projections that growth in North American gas demand would continue to outpace North American supply, and that increasing LNG imports would increasingly tie the U.S. into a global gas market. These projections will be re-examined in light of recent increases in U.S supply, largely from shale, and climate change policies that could significantly increase the demand for gas in the electricity sector.

US and global resource availability	**Rick Smead**, Director Navigant Consulting
Global LNG market	**Charif Souki**, CEO Cheniere Energy
Economics and geopolitics of gas	**Michelle Foss**, Bureau of Economic Geology, University of Texas
Climate policy and demand for gas	**Howard Gruenspecht**, Acting Administrator, US Energy Information Administration

1:30 – 5:00 p.m.

SESSION IV: Regional Focus

Specific economic and political developments in key producing and consuming regions will affect the global supply and demand picture. The Forum will discuss some of the factors at play in the Middle East, Russia and Europe, China, and Latin America.

Middle East	**Joseph A. Stanislaw**, CEO The JA Stanislaw Group
Russia and Europe	**Julian Lee**, Senior Energy Analyst, Centre for Global Energy Studies

China	**Erica Downs**, China Energy Fellow, Brookings Institution
Latin America	**Luis Giusti**, Senior Advisor CSIS
Respondent	**Yonghun Jung**, Executive Director, Korea Energy Economics Institute

Sunday, June 28

8:00 – 11:30 a.m.

SESSION V: Transportation Demand

The transportation sector remains one of the largest and the most uncertain sources of demand for oil. This session will consider the prospects for efficiency improvement and various alternative fuels, the obstacles to their adoption, and the timing of any significant penetration into the market.

Prospects for alternatives and efficiency	**Lee Schipper**, Precourt Energy Efficiency Center, Stanford University
	Theodore Eck, Consulting Economist Institute for Defense Analyses
Toyota outlook	**Jo Cooper**, Group VP, Public Policy and Government/Industry Affairs, Toyota North America
Chrysler outlook	**Reginald R. Modlin**, Director, Regulatory Affairs Chrysler Group LLC

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