2015 Forum on Global Energy, Economy and Security

The New Pricing Reality in Global Oil and Gas Markets

Claire Farley and Bill White, Co-Chairs

Dave Grossman, Rapporteur

The Aspen Institute Energy & Environment Program

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A Report from the 2015 Aspen Institute Forum
on Global Energy, Economy and Security

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FOREWORD

The 2015 Forum on Global Energy, Economy and Security sought to explore the complex set of current and future drivers of global oil and gas supply and demand. The significant drop in oil and gas prices from 2014 to 2015 caught many off guard. Much of the discussion at the Forum this year focused on trying to make sense of the new environment and what it might mean for the future.

In addition, as in the previous three years, there was significant discussion regarding the continued strength and the implications of the U.S. oil and gas boom. Individual sessions also examined additional opportunities for increased production from advances in technology, the international impacts of new North American production, the problems of growing U.S. natural gas production and possible exports, and the environmental impacts of the production boom.

It is our hope that our dialogue process encouraged new, collaborative, cross-disciplinary, and non-partisan thinking. Each half-day session was introduced by brief presentations, with the majority of time reserved for informal and candid dialogue. To encourage candor and create a safe place to explore ideas, all discussions were off the record.

Bill White (Chairman of Lazard Houston, former Houston Mayor, and former Deputy U.S. Energy Secretary) and Claire Farley (Member of the Energy & Infrastructure practice group at KKR) chaired the Forum. Their combined deep knowledge and breadth of experience

in the oil and gas industry helped develop a compelling agenda and gather a highly qualified group of speakers who provided a wealth of information and a variety of perspectives. The diverse expertise of a particularly well-qualified group of participants also added greatly to the richness of the dialogue.

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

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Dave Grossman wrote this report. His extensive knowledge of energy enabled him to understand and capture the highlights of the discussion and present them in understandable language in this report. I also wish to thank Avonique DeVignes, whose efficient and good-natured handling of the administrative arrangements contributed to a smoothly run Forum. Timothy Olson ably assisted her this year while simultaneously organizing several other meetings.

This report is issued under the auspices of the Aspen Institute, and the Forum speakers, participants, and sponsors are not responsible for its contents. Although it is an attempt to represent views expressed during the Forum, not all views expressed were necessarily unanimous, and participants were not asked to agree to the wording.

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THE NEW PRICING REALITY IN GLOBAL OIL AND GAS MARKETS

Dave Grossman
Rapporteur

EXECUTIVE SUMMARY

There is a new reality in the world of oil and gas, characterized by bountiful supply, flattening demand, and a sharp drop in prices. The shale oil and gas revolution in the United States has been a boon for consumers but has created a remarkably challenging environment for producers. With oil prices at $60 a barrel, it is uneconomic on a full-cycle basis to develop new oil in most parts of the world, and production growth rates and upstream capital expenditures in the United States are both rapidly declining. Global oil demand is projected to continue to grow, but the rate and scale of that growth will have huge implications for how quickly excess supply gets used. Similarly, the amount of shale gas supply far exceeds current and projected gas demand, which could put producers in a hole for decades. Projections are that oil prices could be in the $60s for a while and below $100 for an extended period, while gas prices stay around $2.60 for a long time.

Responding in part to the low-price environment, technology developers and adopters are seeking ways to improve production efficiency and address problems constraining production growth. Numerous technologies are being developed, tested, and deployed, including core logging at high resolution to better understand shale reservoirs' variability, creating mobile systems to capture gas that is currently flared, testing when pipelines have the optimal amount of corrosion inhibitors, and utilizing data analytics. The industry, though, takes a really long time to take up new technologies.

Technological innovation has also been pushing in the other direction, attempting to reduce oil demand, particularly in the vehicles market. The story of advanced fuel vehicles, though, has been one of tensions between automakers and regulators – between market pull and regulatory push – and such vehicles still represent a very small portion of sales.

The dramatic oil price collapse and other factors have had dynamic implications for global energy demand, supply, and trade flows. China's energy demand is down as the country's economic growth decelerates, and efforts to institute economic reforms, address the country's dangerously bad air quality, and reform state-owned enterprises will have major implications for the future of energy supply and demand in China: Latin America, the Caribbean, Africa, the Middle East, Russia, and Europe are all facing challenging times with regard to energy (and other issues) as well, with the price drop having negative impacts on currencies, economies, and production and with security concerns threatening to destabilize regional energy systems.

In this global context, America's relatively new energy abundance is raising some challenging issues concerning exports. Momentum appears to be growing for changing U.S. crude oil export policy, though the sense of urgency around the issue has faded and there are questions about how and whether to simultaneously push for repeal of the Jones Act. With regard to natural gas, some U.S. liquefied natural gas (LNG) export projects are being developed, and the nation's gas pipeline infrastructure is getting re-plumbed, though some companies are frustrated with the regulatory processes and approval times for building LNG facilities.

As oil and gas production booms in the United States, and as greater consideration is given to exporting these hydrocarbons to other countries, there has been increased focus on the need for the industry to produce oil and gas responsibly. The potential role of natural gas in achieving American economic and environmental goals has elevated the need to address the issue of methane leakage, and a range of regulations and initiatives by the Environmental

Protection Agency (EPA) aim to do just that. The industry also uses a large amount of water, and some leading companies are pursuing innovative efforts to use it more efficiently and to maximize recycling and reuse of produced and brackish water. The industry, however, has generally done a very poor job with its communications and community outreach. It has to enhance its efforts to get the good things it is doing out to a skeptical public and promote a better conversation.

Major takeaways from the 2015 Aspen Institute Forum on Global Energy, Economy, and Security included the following:

- *Strict environmental regulations and a profitable oil and gas industry are not incompatible.*
- *The global energy landscape today is very different than it once was, and the U.S. oil and gas export and other transportation bottlenecks need to be re-examined and potentially removed.*
- *Given current oil and gas prices and the expectation that prices will be low for quite a while, many small producers and service companies will not come back when production goes back up.*
- *Continued innovation in oil and gas production is essential in this low-price environment, but industry often takes a long time to incorporate new techniques and technologies.*
- *China has great influence over global supply and demand reactions and development prospects but cannot be viewed in isolation.*

SUPPLY, DEMAND, AND PRICING

The shale oil and gas revolution in the United States, along with some other global factors, has spurred significant changes in oil and gas supply and demand, in addition to very low prices. Oil prices, for instance, have fallen significantly, from over $100 a barrel in mid-2014 to around $60 a barrel in mid-2015 (though it should be noted that oil prices from 2011 through mid-2014 were actually quite high from a historical perspective). The dramatic oil price collapse is comparable in magnitude to the drops that occurred in the mid-1980s and mid-1990s. Gas prices have also come down, to around $2.60 in mid-2015. The price drops have been good for consumers paying less for fuel and provided a big boost to the global economy. They have, however, also created a very challenging environment for producers.

U.S. Oil Supply

Total U.S. oil production peaked in 1970 at about 10 million barrels per day (BPD), when the North Slope came online. After that, production generally declined, down to 5.5 million BPD in 2009, but then the shale boom hit, and by early 2015, production had risen to around 9.3 million BPD. Domestic production has been growing at a 1.2 million BPD year-over-year rate for the past year, but that may fall by half during 2015, and by the end of 2015, the year-over-year growth rate of U.S. oil production may well be zero.

U.S. supply is responding to the current prices. All exploration and production companies in the United States have slashed their cap ex budget, there has been a dramatic collapse in rig counts, and an inevitable consequence is that the U.S. oil growth rate will come to a screeching halt (though overall U.S. crude oil production has still continued to grow). Total U.S. crude production in the lower 48, including tight oil, is projected to peak in the second quarter of 2015, come down a lot, and then start rising again in 2016.

The capital markets have been a key driver of production growth during the price downturn, exacerbating the downward. price pressure.

At $60 a barrel, it is uneconomic on a full-cycle basis to develop new oil almost everywhere in the world except the Middle East. The only place in the world where global supply is growing (with any significance) is the United States, and the only significant domestic oil plays economic on a full-cycle basis at that price are the sweet spots of the Eagle Ford, Delaware Basin, and perhaps the San Joaquin. (The Niobara Shale is an excellent field with terrific economics, and virtually everyone with any sort of scale and infrastructure is doing well there with a mix of hydrocarbons, but it is a relatively small part of U.S. production growth.) That means everyone developing oil anywhere else during this period is, on a full-cycle basis, doing so uneconomically. Even in the United States, it will be very difficult to grow production or return cost of capital if $60 prices persist for a while.

The capital markets have been a key driver of production growth during the price downturn, exacerbating the downward price pressure. Private companies can borrow 30-year debt at 3.5%, and that is tremendously rare. With the cost of capital as low as it is, some companies have even been talking about adding back rigs. Private equity, in particular, has been chasing transactions. There are varying estimates of how much private equity is in the market chasing deals, but it could be anywhere from $30 billion to $150 billion.

Capital is getting deployed, good oil and gas properties with solid rates of return are changing hands, and more supply is coming online. Cost of capital and acceptable rates of return are so low that companies that own assets have to decide whether, on margin, they should push the growth accelerator.

It can be a challenge for producers to figure out how much capital to spend – how much growth to attempt – given current prices and the expectation that prices will be low for quite a while. From a portfolio point of view, it may make sense to have a mix of projects in terms of when they come online and the viable price points, but the economics of expensive projects are quite challenging at lower oil prices. Developments in the Arctic, for instance, make no sense at today's prices and will be delayed, but there is still interest in exploration among those looking longer-term and expecting higher future prices. In general, though, the reality so far has been that in a challenging low-price environment, there have been significant reductions in upstream capital expenditures. While the spending cuts raise the question of potential underinvestment in supply in the medium term, several high-capex mega-projects are getting delayed or canceled.

For instance, despite getting a big push from the majors, deep-water exploration has been one of the first things cut. It is very difficult to bring down the costs of ultra-deep-water production enough that a producer could make a full-cycle return at $60 (especially with the heavier regulations post-Macondo). The potential exists to reduce costs through much greater efficiencies in deep-water production, such as through standardization of equipment and processes, but the majors have each invested hundreds of millions of dollars in their own secret sauce and are unlikely to be willing to standardize unless it is the only way to make the projects viable.

There has, however, been a great deal of focus on efficiency within the sector generally, applying technology to drive well costs down and get better supply for each dollar invested. The improved efficiency maximizes the profitability of assets producers already own; getting the most bang for the buck out of existing inventory may better maintain flexibility until there is greater clarity on the market price environment. The improved efficiency also means the rig count likely will not return to its previous levels, as fewer wells are needed to achieve higher levels of production.

Not all cost reductions are sustainable for the long-term, though. With the plummeting rig counts, service companies have been cutting staff and bidding like crazy on the work that is left. To lower costs, service companies are looking at surface efficiency (e.g., smaller footprints, fewer people, better pumps, less equipment), logistics and procurement (e.g., for sand and proppant), integration (e.g., acquisitions), and service quality; some are also trying to offer more turnkey solutions to customers. It has gotten to the point that service companies are offering their services at pretty close to cash cost, but it may not be sustainable to push the service companies down that low. If that situation persists for two to three years, a lot of these companies will not come back when production goes back up; equipment gets mothballed, people leave, and engineers switch fields.

Still, looking long-term, scenarios out to 2030 by the U.S. Energy Information Administration (EIA) suggest that the United States could be playing a larger role in the global oil market balance than would have been expected a decade ago. U.S. crude supply could go up a lot, plateau, or decline after 2020, depending on prices and technology, but the United States is likely to be a major long-term producer of oil. There is a huge amount of uncertainty going forward, though, in terms of the exact shape of the supply curve for U.S. tight oil, access to capital, and cost reductions. (No one knows the true cost curve for U.S. tight oil production; all past cost curves were wrong, and all existing ones are being re-written.)

U.S. Gas Supply

The U.S. supply of shale oil is not nearly as prolific as its supply of shale gas. There are far more natural gas shale plays in North America than crude oil shale plays, and there is an abundance of dry and associated gas. Shale gas has represented a revolution in American energy and in the country's geopolitical position.

The revolution has not necessarily painted a pretty picture for North American natural gas producers, though, and it is expected to get uglier. The amount of shale gas supply is enormous relative to demand, which could put producers in a hole for the next 20-30 years. The Marcellus, Utica, and (newly) the Haynesville will likely be the low-cost basins. Marcellus production, now about 20% of the U.S. total, is currently at about 13 bcf, having recently been at 3 bcf; in three years, it is expected to go to 23 bcf and represent 33% of total U.S. gas production. The enormous supply in the Marcellus is held back at the moment only by limited pipeline transport to get the gas out of Pennsylvania; the production potential is there, but it is waiting for the ability to get to market. There are signs that portions of the Utica, which is just developing, will be like the Marcellus – and that potential is not factored into most estimates of supply. As for the Haynesville, it has the potential to be a new supply sleeper, with bigger fracks turning into bigger wells turning into a monster supply of gas. There is at least a 50-year supply of shale gas in North America, and technological improvements are likely to spur big advances in getting more gas out of the same reservoirs. While there could be a huge increase in demand for gas through 2020 – including LNG exports – the increase in supply is still greater.

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This was not the future of natural gas that had been projected a decade ago; the views in 2005 in no way match the facts in 2015. In 2005, utility executives were told by consultants and others that there was no chance that natural gas prices would ever go below

$10. In 2007, they were told that shale gas in 2014 would produce at most 3.4 bcf of supply and that the country would be saved by LNG imports. In 2014, it was 35 bcf – off by a factor of 10 – and imports were negligible. Utility executives made decisions and long-term investments based on these forecasts, which were entirely off-base.

Overall, North American gas is a great story for the country, for the economy, for the chemical industry, and for all users of gas, but it is a miserable story for producers.

United States as Swing Supplier?

The boom in U.S. oil supplies has essentially made the United States something akin to a swing producer on the global stage – or perhaps, more accurately, a very quick responder. U.S. shale oil production is more responsive to market signals than conventional oil but not as responsive as Saudi oil. There are numerous decision-makers in the U.S. market; it is not quite the same as Saudi Arabian decision-makers getting around a table and deciding on production levels. If the Saudis maintain their high production for a while, the United States might start to play more of a swing role, but it is not really swinging yet. The implications for oil price volatility are unclear if OPEC stays where it is and the United States swings a bit. OPEC has very little spare capacity anymore; the United States can potentially be a more effective buffer against volatility now.

When it comes to LNG, however, the United States may well be 100% of the swing supply in the world.

Demand

The balance between supply and demand is obviously very important, but growth in oil demand is a source of significant uncertainty. Forecasts at the beginning of 2015 projected 600,000 barrels per day to 1.6 million barrels per day of global liquid fuels demand growth, which is a sizable spread, with huge implications for how quickly excess supply gets used. Current global crude demand is around 93 billion

BPD and has been growing (mostly outside of the OECD countries) at roughly one million BPD per year for the past six years or so, even during the recession and low oil prices. Looking ahead, the EIA sees that trend continuing, projecting world liquid fuel demand to grow 12-13 million BPD from 2013 through 2025, with small growth in OECD demand but much more in non-OECD countries. Projections of oil demand growth could be substantially overstated, though, given the likelihood of a much more energy efficient world (whether due to climate efforts or economics) and the potential for global population growth to slow or stop.

A key question about oil and gas demand is the relative importance in various regions of prices versus policy decisions.

The projected demand for U.S. gas through 2035, while rising significantly, suggests there will be a large surplus of gas that cannot be consumed by domestic demand even under ambitious scenarios. For some utilities, coal has declined as a fuel source by more than a third while gas has increased fivefold in just 10 years; that is huge, and natural gas will keep growing (though not as rapidly) within utility fleets. U.S. environmental policies such as the Clean Power Plan might spur greater demand for gas to replace coal, but in the long run, the reduction in coal generation mostly benefits renewable energy and energy efficiency. Globally, coal consumption is concentrated in very few places (e.g., China, India, somewhat in Europe), and energy mix decisions in those places will have a big influence on global gas demand.

A key question about oil and gas demand is the relative importance in various regions of prices versus policy decisions. The EIA's scenarios out to 2030, for instance, suggest that the United States (which is the biggest global user of oil) will see falling motor gasoline demand, driven primarily by fuel economy policies, while pending policies could lower demand for diesel and jet fuel as well. Places with a priority on climate change could similarly see reduced demand for hydrocarbons, though natural gas might have more of a role due to its substitution effects. On the other hand, security concerns are also a driver of demand, particularly for crude and LNG, and countries (e.g., in Asia) have been seeking supply options from more stable parts of the world.

Pricing Forecasts

Oil price forecasting is a fool's errand, but people still do it. General consensus holds that prices will be below $100 for an extended period of time. The EIA's baseline forecast for Brent crude is about $61 a barrel in 2015 and $67 in 2016, but the market-implied confidence band is extremely wide (i.e., those forecasts should be taken with several grains of salt). Others project prices to stabilize in the near term around $75. While oil prices may rebound, some expect them to get worse before they get better.

There are many global factors that could lead crude prices to be higher or lower. Saudi Arabia could increase production from 10 to 10.5 million BPD. If an Iran nuclear agreement is signed in 2015, Iran could come up with another 0.7 million BPD. If prices start to move north of $80, U.S. production could grow again. All of these could end up pushing prices back down. On the other hand, there is virtually no chance that shale oil from anywhere but the United States will hit the market for the next 5-10 years. If Iran does not come online as quickly as some expect or the activities of ISIS substantially disrupt oil supplies, the price of oil could rise. There are many moving parts in the geopolitical world, and it is possible that a lot of oil might not actually get to market.

As for gas, Henry Hub as of June 2015 was about $2.60, and some expect that to be the general price for a long time. Futures curves projecting gas prices at $3.50 may be optimistic, as they do not factor in supply from the Haynesville, portions of the Utica, and technological advances.

THE EFFECTS OF TECHNOLOGY ON SUPPLY & DEMAND

Innovation in a low-price environment is essential, as technology developers and adopters seek ways to improve production efficiency and address problems constraining production growth. At the same time, driven by environmental and other concerns, there have been technological developments aimed at reducing reliance on oil – most notably in the transportation sector.

Technology Affecting Supply

Science, technology, and geology are vital for understanding unconventional wells and getting them to perform as expected. Wells that are only a couple of miles apart and have minor variability in porosity, permeability, thickness, and pressure can exhibit huge variability in terms of well performance and ultimate recovery. Shale reservoirs are complicated, and current technologies and modeling do a poor job of accounting for their variability. Instead of macro data for a micro problem, there is a need to understand the fabric and layers of the rock with core logging at a centimeter or millimeter resolution, enabling more realistic simulation models and better understanding

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of why a well is fracking as it is. Companies are also beginning to use or experiment with microsesimic monitoring to visualize how fracks are taking place and downhole fiber optic monitoring for fracks. This high-resolution data can facilitate decisions about where to land laterals to connect to more of the reservoir; changes as small as 10-20 feet can have huge impacts in production and can markedly increase recovery per well, improving reserves and rates of return. There is a lot more to squeeze out of the rocks, though the question of how best to extract the huge potential of under-performing wells is a mechanical one. In some cases, re-fracking the same well may be the best way to re-harvest the same rock (and technological progress is increasing there), while in other cases, it might be better to drill a parallel well and execute a new frack.

Startups in the oil and gas space are pursuing other technological innovations by looking at basic science, better design, cross pollination from other fields, and data analytics. Some of the basic science work involves moonshot efforts, such as converting methane to ethylene, while other work involves step changes, such as capturing carbon dioxide and some SOx and NOx and turning it all into baking soda and other practical products. Better design efforts include using metal to plug wells instead of cement (enabling a plug in an hour that is 100% tight and fits any deformities downhole), creating solid state generators to power rigs, and creating mobile systems to capture gas that is currently flared, compress it, and transport it to end customers. Cross pollination efforts include testing when pipelines have the optimal amount of corrosion inhibitors in the coating (drawing from biological testing) and using the drill string as a communication medium to acoustically transmit data up and down the stream more cost-effectively and faster than a mud pulse (drawing on signal processing). There is also a ton of action happening in data analytics, including predictive analytics and natural language auto-learning artificial intelligence. Service companies are exploring further innovations as well, including increased automation, integration of the sensors in the equipment across product lines, and customized chemistry.

The industry, though, takes a really long time to take up new technologies, even if those technologies are no-brainers. Systems today are far from optimized and produce an inordinate amount of waste and inefficiency, but techniques and technologies available in the marketplace to reduce that waste have had slow uptake. For instance, there are novel completion techniques currently available that reduce the trucks coming to and from the well site, cover the formation in a more professional manner, improve the economics, reduce water usage, reduce proppant usage, increase production, and allow operators to avoid drilling wells that do not need to be drilled – but these have not yet been widely adopted. Perhaps one of the reasons for the slow uptake is the fact that operators compete with one another, with very little collaboration on technologies or sustainability. There is no standardization within the service or operator sectors, partly due to a lack of willingness among firms that have invested in proprietary technologies and partly due to anti-trust laws.

Technology Affecting Demand

Technological innovation has also been pushing – for a long time – in the other direction, attempting to reduce oil demand. The clearest manifestation of this effort is in the vehicles market.

The story of advanced vehicles has been a bit of a dance between automakers and regulators. When GM launched the EV1 in the 1990s, spurring other automakers to start developing their own electric vehicles (EVs), California regulators adopted a Zero Emissions Vehicle (ZEV) mandate, aiming to have 10% of all new car sales in California be ZEVs by 2003. Automakers were willing to sustain a market pull environment but not a regulatory push approach, started viewing the regulation as a tax, and moved to reduce their liability. By 1999, this stage of EVs was all but over, the consumer pull market never materialized, and a sense of mistrust had arisen between automakers, NGOs, and regulators that persists to the present day.

More recently, during a second wave of EVs tied to the launch of the Nissan Leaf and the Chevy Volt and accelerated by the launch of the Tesla Model S, policymakers have again been touting EVs as the future, providing subsidies and rebates. Early adopters, though, have been far more engaged by the discounts than the environmental attributes, and states that have scaled back their EV subsidies have seen big decreases in EV sales. Even with plenty of EV options on the market, a recovering economy, and lots of incentives, EV sales have been mostly flat in California and across the country. There could be many reasons for this, including lower gasoline prices, the lack of chargers, and the rapid depreciation of most EVs (which could spur price-conscious buyers to just buy a cheaper used EV than a new one). Nevertheless, California regulators have again set ZEV requirements, aiming for 22% of new car sales by 2025, which is a very high figure, especially since EVs represent less than 1% of sales in 2015. Regulators have no ability to force consumers to buy EVs but appear unwilling to be patient and let market pull work.

In addition, automakers will soon launch internal combustion engines that are almost 40% efficient, which will challenge competing technologies and make the payback for them tough to justify from a pure economics standpoint. Still, there could be niches for CNG-gasoline hybrids (e.g., for pickup trucks and oilfield service trucks), LNG (e.g., for rail), and fuel cell cars, assuming the lack of filling stations is addressed. It is also possible that the model of individual car ownership might get turned upside down over the next 10-15 years, particularly given the Uber model and the apparent reduced interest in driving among the younger generation.

THE ENERGY PICTURE AROUND THE WORLD

Numerous factors, including but in no way limited to the dramatic price collapse, have had dynamic implications for global energy demand, supply, and trade flows. What is happening in China has the greatest implications on the global stage, but supply and demand reactions and prospects around the world are also important.

China

In China, overall energy demand is down as the country's economic growth decelerates. Most oil in China is consumed in industry, so as industrial production slows, diesel demand slows with it; in addition, there is a strong political imperative to strengthen tailpipe and fuel economy standards, and passenger vehicles in China are driven many fewer miles than in the United States. Coal is getting hit hard with the slowdown in industrial production and electricity demand (as well as increased supply diversity), and the long-term outlook for coal in China is very grim. As for natural gas, projected demand in Asia in 2018 has been revised downward across the board, though gas has the potential to pick up demand in the transport and power sectors, and China's eye-popping commitments around renewables could be complementary or competition for gas.

More specifically, there are three domestic megatrends affecting the future of energy supply and demand in China: economic reforms, the 'airpocolypse', and state-owned enterprise (SOE) reforms.

First, President Xi Jinping is trying to engineer an aggressive program of economic reforms. Chinese economic growth is slowing as the country reaches middle-income level, which has been a precarious situation for countries. Countries at that level that can successfully institute reforms to their economies can take the 'bunny slope' down to lower annual GDP growth rates. Those that could not institute reforms (e.g., in Latin America) took the faster, steeper, 'black diamond' route down. For China, these reforms mean shifting from the government being the owner of the means of production to a regulator of production activity for the benefit of consumers, which is a challenging shift for any economy but even more so for a formerly planned one. The structure of the economy also has to change, rebalancing away from the past drivers of growth (e.g., investments in infrastructure, construction, and heavy industry) and towards the service sector and domestic consumption, which will significantly reduce the energy intensity of the economy; even if the Chinese economy is growing at 6% to 2020 (the best case scenario), expected energy demand growth would only be about 2-3% instead of 8-10%. If China is unsuccessful in rebalancing, economic growth in 2020 would look more like 1-2%, which would mean negative energy demand growth by the end of the decade.

There are three domestic megatrends affecting the future of energy supply and demand in China: economic reforms, the 'airpocolypse', and state-owned enterprise reforms.

The key is capital. SOEs are energy-intensive heavy industries that have had preferential access to significantly underpriced capital, and SOEs with strong connections in government will fight hard to keep the capital system as it is. Cheap capital allowed China to compress infrastructure development that usually takes 30 years into 10 years and to pull forward the next 10 years of energy demand into the past 10. If that capital is moved from SOEs to high-performing private sector companies, it can drive growth and unlock more productivity in the economy, but it will likely cause near-term pain (as it takes a while for private demand to pick up). China's choice is riding out the near-term pain and maybe having 6% growth in 2020 or being weak in the near term, opening the taps again to run more liquidity into the system, having the energy intensity of the economy skyrocket, having another couple of years of 7-8% growth, and then having growth plummet down to about 2% by 2020. Either way, every outlook about Chinese energy demand is too high, extrapolating from a rate of growth and an energy intensity that is not plausible for the future.

The second megatrend is the 'airpocolypse', which has threatened political stability. The air in China has been bad for a long time, but the country has reached the income point where people's other needs are met, they are willing to pay more for cleaner air, and the air pollution has become an economic liability to the country (e.g., it is hard for Chinese companies to attract and retain talent). There are also, of course, health consequences. There is no way or desire for political leadership to make this issue go away, and there are factions within the government who believe cleaner air is vital to long-term economic growth and are willing to use public anger to drive SOEs and other interests to make necessary changes. This will have an impact on the energy mix. After a massive wave of coal plant building, most of the incremental capacity coming online now is non-coal generation, and beyond 2020 there will be very few new coal-fired power plants. There have been big renewable energy additions, exceeding expectations, both rooftop and central station. Reforms could also unlock a fairly large amount of gas, principally if electricity prices start to reward dispatchability.

The third megatrend is President Xi Jinping's corruption purge and attempt to reform the SOEs. The corruption purge in SOEs began with the energy sector, which has led to rigor mortis operationally in the state oil companies and caused a huge drop in drilling activity. The swashbuckling heads of three Chinese oil companies have been replaced with party apparatchiks that are keeping their heads down. It is now a risk-averse environment, where making risky investments overseas or domestically does not pay off. In addition, oil and gas reform is expected by the end of 2015, which could include liberalization of the current upstream duopoly in oil and gas. The big variable on the gas side is what happens with electricity sector reform, which has been the hardest nut to crack. The state grid is by far the most politically powerful SOE and the most resistant to reform, but there are beginning to be hints of change about power market reform, including potentially allowing more time-of-use pricing and allowing consumers to negotiate directly with generators for purchases, which could be a big deal for gas and renewables. If electricity reform goes well and if the push to reduce pollution continues, then there could be a significant uptick in Chinese natural gas demand by 2018; there is also the potential for robust demand after 2018 as a balancer for renewable energy.

Everywhere Else

Challenging times in the energy world are by no means limited to China.

Latin America has excellent reserve potential, but actual production in many countries in the region is declining due to lack of investment and other challenges. Mexico finally enacted energy reforms and opened its markets only to have the price crash, but there will be good opportunities there. The United States has also been engaging bilaterally with Mexico to explore how to expand the country's use of natural gas to meet climate and energy objectives and how to ensure Mexico develops its resources in a prudent manner. The drug cartels in Northern Mexico are a serious issue, though, and unconventional reserves there are challenging to develop because of security concerns. In Argentina, the industry is challenged by what is essentially an import ban in the country; bringing in equipment, supplies, and material is very difficult. Argentina needs some regulatory stability and further development of the service company sector. As for Venezuela, it has a great deal of potential – the kind that could really disrupt supply and demand – but the price drop has led to GDP losses and rising inflation. In general, to make some money developing and investing in South America, it takes a long-term view, a strong stomach, an understanding of political risk, and a willingness to fight year in and year out. It is a harder place to operate for large, high-visibility companies with a lot of retail exposure. There are niches for investment, though, and private equity teams are scouring the region for deals because the resources are there – and the teams are taking a long-term view.

Europe may need to import more gas in the future – given its own declining production, the phasing out of coal and nuclear plants in some places, and the need for backup for renewable energy production – and there is a real question about what share of European gas demand will be met by LNG.

In the Caribbean, many countries that had been credit financed by Venezuela for a long time are now seeing that subsidy disappear. Countries have electricity prices three to four times higher than those in the United States, are using diesel for generation, and are seeing credit deficits. These countries might try to follow Mexico's lead by converting to gas, but they will be challenged to make a market, given the small volumes involved. Some sort of credit guarantee for these countries – so they could sign 20-year contracts instead of having to pay spot prices – would be hugely beneficial for affordability in the region, but there is no real indication of that idea gaining traction. In general, though, increasing natural gas and renewables in the Caribbean could help alleviate concerns about Venezuela and ensure affordable and reliable energy.

In Africa, producers were facing challenges even before the oil price drop, given the geology, political conflicts, tough fiscal terms, rampant corruption, and weak capacity in some countries. The price drop made things even worse, dragging down Nigeria's GDP outlook, for instance, and causing serious challenges and delays to deep-water projects in West Africa (and when expensive projects get put off in these countries, they get put off for a while). Algeria, meanwhile, exemplifies some of the other challenges African producers face. The country has a huge shale gas resource, which could represent a revolutionary alternative source of supply right on Europe's doorstep, but Algeria has a lack of services, poor understanding of the geology, and extremely disappointing production results. Historically, Algeria has been unable to get out of its own way to create a framework that would make it economic for strong industry players to come in and develop that resource. Right next door, Libya is riven by civil war, and ISIS is near its major oil fields, so it is conceivable that Libya's oil resource could disappear (and unlike Iraq, the cavalry is probably not coming to Libya). Egypt is a different story; it has an enormous domestic gas market, the infrastructure build-out opportunity seems good, and it has a government that will likely keep its word.

As for the rest of the Middle East, much of it is in crisis. Yemen and Syria are riven by civil war. Iraq is dealing with ISIS as well, and getting more than the easy oil there will require significant investment that is hard to envision happening. Iran, after the nuclear deal, might get to sell its oil in the market, though it will not be a huge player, it will not happen immediately, and a lot of real work needs to be done there (i.e., it is not just turning on a valve); a lot of the projections about near-term Iranian oil production may be overly optimistic. With regard to Saudi Arabia, which is clearly the key energy player in the Middle East, it is currently focused primarily on market share and regional security. The Saudis (and the equally wealthy UAE) can ride out this price drop for a while, and Saudi Arabia has already drawn tens of billions of dollars from reserves over the past year. The northern Gulf countries, however, have no such reserves, which puts the Saudis in a strong position to negotiate regional security and market share within OPEC, particularly with Iran and Iraq. If the Saudis can get a deal on security that also addresses the concerns about ISIS, then the need to keep Iran or Iraq down within OPEC becomes much less important; a deal on security could yield a deal on production.

In Russia, the ruble is going down, but so are costs – almost offsetting the impact of falling commodity prices – and Russia is focused on building service companies in very little time to achieve greater cost reductions. New greenfield development is impaired by the government's fiscal regime (taking large percentages of revenue) and by U.S. sanctions related to Ukraine, but those will not hinder near-term production from Russia's existing conventional, water flood assets. Russia therefore may remain a fairly steady producer in the near term despite the price drop, but the combination of oil prices and sanctions still spell trouble for its economy a few years out.

Europe, meanwhile, has become increasingly import dependent, and angst about the security of supply given the situation with Russia and Ukraine has led to declining opposition to developing European hydrocarbon resources and to importing U.S. LNG. There are lots of interesting developments in Europe, with efforts to tighten the EU carbon caps (which will help gas), Germany trying to set targets on coal, the oil price drop creating further challenges and delays for deep-water projects in the North Sea, and steps in Brussels to invest in resilience to disruptions in Russian supplies. Europe may need to import more gas in the future – given its own declining production, the phasing out of coal and nuclear plants in some places, and the need for backup for renewable energy production – and there is a real question about what share of European gas demand will be met by LNG. Some there are pushing for more LNG import facilities, and some European governments are engaging in technical collaboration with the U.S. government on unconventional gas development so they can address public concerns about importing U.S. LNG.

U.S. EXPORTS

The United States is still in a massive transition as a nation, from a mindset of scarcity to one of abundance – whether on gas, oil, renewables, or efficiency. The nation has never been here before. It is a story of technological innovation, relentless application, and know-how. The abundant supplies of energy have allowed the country to back off on imports, but they have also raised some challenging questions concerning exports.

Crude Export Ban & the Jones Act

Momentum appears to be growing in the country for changing U.S. crude oil export policy. The sense of urgency around the issue has faded, however, due to the spreads being so narrow between benchmark crudes, U.S. oil production growth slowing and flattening, and the refinery system in the country doing a pretty good job keeping up with production growth. Some therefore see a change in oil export restrictions as good to have eventually but not vital to have immediately. In addition, the political challenges involved in ending the crude export ban should not be underestimated. It is possible that policy changes will come not from legislation but from executive action in the next Administration (regardless of party), probably for foreign policy and geopolitical reasons, just as the Obama Administration's actions on LNG exports have been influenced by geopolitical security arguments.

Another dicey political issue related to the export ban is the Jones Act, with advocates for removing the ban often told not to make Jones Act reform a priority. Because Jones Act vessels are much more expensive than foreign-flagged vessels, the Act heavily affects the affordability of marine transport for crude (and for refined products, for which there is currently a level of refined product arbitrage based on the costs of transport to and from the Gulf Coast, Midwest, and East Coast). It costs the same to move crude from Texas to Louisiana on a Jones Act vessel as to move it from the Gulf Coast to Canada on a foreign-flagged vessel. Due to the Act, it costs more than twice as much to ship from the Gulf Coast to the East Coast as to ship from the Gulf Coast to Europe, leading to oil being shipped to Europe, refined there, and then shipped back. One of the reasons for the high costs is that there are only about 165 Jones Act vessels (about 13% of the number in 1950), there are only two yards, and it is not clear there is any ship-building really left in the United States.

Repealing the crude export ban without changing the Jones Act produces no change in the cost of shipping crude from the Gulf Coast to the East Coast.

Repealing the crude export ban without changing the Jones Act produces no change in the cost of shipping crude from the Gulf Coast to the East Coast. Repealing the ban and changing the Jones Act to make it competitive on a global scale would result in a huge price drop in shipping from the Gulf to the East Coast, hurting East Coast refiners' profits but benefiting Gulf Coast and Midwest refiners. Policy changes can have a clear impact on the downstream industry.

U.S. LNG

Unlike crude, North American natural gas is an island commodity. To get off the island, it has to be liquefied. That is increasingly in the realm of the possible, but there are finite amounts one can move off the island. LNG exports will not even come close to fixing the oversupply situation, but they may increase gas demand on the margin, and they could be very significant for some shale gas producers.

Global demand for natural gas is strong, and the U.S. supply and price stability create an advantage that supports exports. U.S. LNG contracts are already having impacts on the global balance that cannot be understated, and the LNG market the U.S. is entering is fundamentally different from the one it left behind. U.S. LNG export projects are underway, with six liquefaction projects already getting Federal Energy Regulatory Commission (FERC) approval and five getting Department of Energy (DOE) approval; there are over 10 bcf/d under construction, with the primary geography around the Gulf Coast. The projects underway should get the United States to roughly Qatar levels of export capacity. Where that supply goes could have important geopolitical and economic implications.

Global demand for natural gas is strong, and the U.S. supply and price stability create an advantage that supports exports.

It took decades to build the infrastructure that brought gas from the Gulf Coast to the Northeast and from Kansas and Oklahoma to the Midwest and Northeast. During the last five years and over the next three, that infrastructure is getting reversed, with gas flowing to export terminals from places that used to be markets but now are production basins. Facilities built a few years ago to convert LNG imports to natural gas are being transformed (expensively) to produce LNG; there may also be a role for smaller scale LNG facilities that are cheaper, more efficient, and scalable (i.e., can add incremental capacity). The United States is effectively re-plumbing.

The re-plumbing can only go so far, though. The low-hanging fruit within the interstate pipeline system will be gone by 2018, and the next big chunks of capacity to get gas out of the Northeast will be more difficult, cost more, and require major infrastructure.

Building an export facility in the Northeast is not a particularly viable option, however; property values for land to build a big facility would be very high, and deep-water ports are very finite on the East Coast (and the ones that exist are pretty well built out).

Companies trying to build LNG facilities have expressed some frustration with the lack of a fixed timeline for getting a permit, the length it takes to get one, and the fact that it comes so late in the process. Customers will not commit on an indefinite timeframe, and contractors to build the facility cannot leave their offers open indefinitely. Months and days matter, as does certainty. Some in the industry wish that DOE had continued issuing conditional authorizations; DOE changed the process to stop issuing those (aside from Alaska) and to instead consider applications when they were ready for final approval. On the other hand, it should be recognized that these issues are new to regulators, and new processes had to be created within FERC, DOE, and elsewhere. Regulators are trying to create transparent, predictable, thorough processes that give confidence that the range of issues involved (e.g., engineering design, community impacts, brownfield versus greenfield) are addressed and that orders can stand up in court. While processes may feel slow, LNG export infrastructure is being developed at a record pace compared to the time it took to build the interstate pipeline system; government could always move faster, but it is better than it was before.

In addition to the LNG exports, there has also been a significant increase in natural gas exports by pipeline to Mexico. Some of that gas is expected to fuel power generation for the industrial base in Northern Mexico, but some of it could get liquefied and exported from Mexico.

ENVIRONMENTAL & COMMUNITY CHALLENGES

As oil and gas production booms in the United States, and as greater consideration is given to exporting these hydrocarbons to other countries, there has been increased focus on the need for the industry to produce oil and gas responsibly. The federal government is trying to pursue a coordinated R&D strategy – including on air quality, water use, water disposal, induced seismicity, wellbore integrity, methane leakage, and other areas – so policymakers can understand what the key risks are. The industry also faces environmental regulations, including on methane, greenhouse gas emissions, water management and protection, and impacts on communities, land, and wildlife. Beyond affecting the industry's operations, all of these issues can also affect the industry's interactions with the public and its social license to operate.

Methane, Climate, & Air

Natural gas is important for the Obama Administration's economic and environmental goals, but it views getting a handle on the issue of methane leakage as absolutely essential. The United States will be hard-pressed to meet the ambitious commitments embodied in its pledge leading up to the Paris climate negotiations without significant reductions in methane emissions. The goal from the White

House is to reduce methane emissions from the sector 40-45% from 2012 levels by 2025.[1]

There is great disparity among studies about how much methane is actually being emitted by the sector and from where. Studies have clearly shown, though, that not all equipment is equal. It turns out that a small percentage of sources account for an enormous percentage of the methane emissions. These 'fat tails' represent both a challenge and an opportunity for policy; it may not make sense to prescriptively plan fixes at every single piece of equipment, but more intelligent and flexible performance-based approaches could be very effective.

The methane conversation is more focused now on concrete action than on trench warfare.

While there is methane action at a number of agencies, including DOE, the Bureau of Land Management, and FERC, most of the action is at the EPA. The agency issued white papers in 2014 trying to identify the biggest unaddressed sources of methane in the sector, and there appear to be a number of readily available low-cost options to reduce emissions. Associated gas from oil wells has already been effectively regulated by another rule requiring green completions (to address volatile organic compounds, or VOCs), but there are other areas of potential focus within the sector, including liquids unloading, compressor stations, pneumatics, and leaks – all of which have clear abatement strategies (e.g., plunger lifts, move to low- or zero-bleed controllers, leak detection and repair).

The EPA is pursuing a three-pronged hybrid approach to address different types of leaks in different parts of the natural gas chain. First, during the summer of 2015, the EPA will propose Control Technique Guidelines, providing guidance to states on what they should be doing to address major sources of VOCs, which are pre-

1 Note this Forum took place before the August 18, 2015, rules proposed by the Environmental Protection Agency aimed at cutting methane emissions from new oil and gas production.

cursors to ozone; the guidelines will include oil and gas sources of VOCs, which will mean methane reduction co-benefits, though only in significant ozone non-attainment areas and only in the upstream part of the chain. States do not have to do precisely what EPA says, but many will.

The second prong, a proposed rule under section 111(b) of the Clean Air Act expected during the summer of 2015, focuses specifically on methane. The proposed rule would only address new and modified equipment, but it could have farther reach along the value chain. It also means that at some point there will be a follow-up rule under section 111(d) addressing methane from existing equipment – which is a much bigger and more complicated universe – though it is not clear when that regulation would happen. (In addition, the EPA's authority under section 111(d) is likely to get clarified during the major litigation expected around the Clean Power Plan.)

In the meantime, and perhaps to forestall such regulation, some in the industry have expressed willingness to take voluntary actions to achieve more reductions on a faster timetable. The third prong is thus the EPA's proposed new enhanced voluntary Natural Gas Star program. There are already several companies in voluntary efforts such as ONE Future and the Downstream Initiative that have offered ideas on what a realistic and credible voluntary program could be, whether best management practices or more of a performance-based approach. The industry is far from monolithic on the methane issue, though; some companies do not see methane as much of a problem, think regulations are inevitable anyway, and see no guarantee of credit for early actions – and so are remaining on the sidelines for now. Still, over the past couple of years, many in the industry have gotten past their initial defensive reaction to the methane issue, better understood the reputational risks involved, and realized that available technologies and practices can address the problems; the conversation is more focused now on concrete action than on trench warfare.

With regard to climate change more broadly, there is antipathy to oil and ambivalence about the role of gas among climate activists. The industry argues that gas should be the destination, as coal-to-gas switching around the world could dramatically reduce greenhouse gases, while others see gas only as a bridge and fear that too much focus on gas will delay the transition to a zero-carbon economy. Many climate activists are also ardently opposed to the Keystone XL pipeline, while most in industry think it ought to be approved and built (but are also exhausted and just want a decision to be made). The pipeline has become symbolic, and perhaps even more than the decision itself, the rationale behind the decision will be tremendously important; if the pipeline is rejected based on a climate rationale, that rationale could apply to many other things and have a much broader impact.

Beyond climate concerns, global transitions from coal to natural gas could have huge benefits in terms of just cleaning the air and eliminating the particulates and other pollution that kill people today. The health benefits could be enormous, affecting the quality and length of people's lives.

Water

Some in the industry question the public focus on the amount of water used in hydraulic fracturing, seeing it as relatively immaterial compared to other water uses. Still, water is the ideal medium for fracking, as it is compressible, non-explosive, and inexpensive, and the industry does use a large amount of it. The key is to use it more efficiently and effectively and to maximize recycling and reuse, and there is real cooperation within the industry to share information and find better ways to mitigate risks related to water management and protection.

Some leading companies in the industry are working to reduce the costs of recycling produced water or using brackish water. There have been a lot of developments in fracking chemistry that now allow for the use of such water (and that have reduced the more dangerous chemical additives in fracking fluids). The specific approaches and technologies involved in treating and reusing water will likely vary by location and company need, affected by the type of water being used, limitations of disposal, and the like; there is not a one-size-fits-all solution. The economics for recycling and reusing produced water are good in many places, though.

Using treated produced water instead of freshwater and piping it to locations instead of driving represents a big opportunity for the whole industry.

Using treated produced water instead of freshwater and piping it to locations instead of driving represents a big opportunity for the whole industry (at least in places where there is produced water and/or brackish water). Produced water is a major resource for the industry to reuse, simultaneously mitigating a range of other problems, including reducing truck traffic to and from a site and addressing concerns about induced seismicity (by avoiding the need for injection wells). Water reuse and recycling help with public acceptance.

While some operators are at the front of the wave, a great many are not. The percentage of produced water being recycled in the United States is currently in the single digits, and some companies are still injecting water into wells where there are earthquake swarms. The industry still has a lot further to go.

Communications, Outreach, & Responsibility

One area in which the industry has done a poor job is in communications and community outreach. In fact, the industry has mishandled its public communications with remarkable consistency. Technology can solve the methane and water problems, but not the community and communications problems.

The industry's typical initial response to an issue is to deny that a problem even exists. It did so again in the summer of 2015 with the draft study by the EPA about the effects of hydraulic fracturing on drinking water, claiming the study showed there was no problem, which is not quite what the study said. There are real problems out there, though. Oil trains really are derailing and exploding. Earthquakes really are on the rise in some places with injection wells. There really is a tension between the boom in hydrocarbon production and addressing the climate challenge. There really are cumulative effects from development at scale. Repeatedly denying that these are issues does not serve the industry well.

Even where the industry is "right", being right is not necessarily the whole answer. Stakeholders ask questions about their concerns, sometimes phrased with slight inaccuracies, and the industry gives technically correct but completely unhelpful answers. Engineers in the industry are giving engineering answers to people who are scared and concerned. Those kinds of responses help issues take on lives of their own, whether there is credible science behind them or not, and the public's perceived risks can spur regulations at various levels of government.

The industry's typical response to regulation, in turn, is that it does not want to be regulated and that the regulations in place are not reflective of industry processes, are not cost effective, and do not allow for industry innovation. Those answers do not satisfy the public's concerns. The industry always says new regulations will be expensive and unachievable, but the industry also always comes up with very clever solutions. Experience in the United States, Norway, and other countries bears this out time and again; strict environmental regulations and a profitable oil and gas industry are not incompatible.

The industry has generally been too dismissive of those opposing it, but it dismisses them at its peril. In today's world, communication is instant; everyone knows what the industry is doing. The industry is also now working in communities that have never seen its work before. There is lots of opposition. The environmental community that saw (and still sees) the future moving to renewables is using communications to tell people the negative things about oil and gas, and countries are banning fracking and creating paradigms involving the phase-out of fossil fuels.

The industry has to think about the way it communicates and figure out how to get the good things it is doing out to a public that tends not to believe what the industry says. It needs to be transparent, use the facts to gain public trust, and talk about the moral case for what it does and the contributions it has made to society. The industry has to come up with a better way to educate the country about what it is doing to reduce emissions, use water better, and the like. It needs to follow the example of some of its leading companies by participating in collaborative efforts to create and advocate for smart regulations that make sense to apply across the industry and by going above and beyond regulatory requirements. In short, the industry has to figure out how to promote a better conversation.

Appendices

Agenda

Wednesday, June 10

8:30 – Noon **SESSION I: GLOBAL SUPPLY & DEMAND AND NEW PRICING REALITIES**

What are the current and future drivers of global supply and demand for petroleum? How have forecasts and forecasting changed to address current prices, supply and demand? Can demand "peak?" What should we look for as signs that the fundamentals of supply and demand have shifted? How and when will oil price volatility affect North American daily production and reserve estimates? How will companies and investors find opportunity amidst the unpredictability? Will innovation in the transportation sector impact demand?

Oil Markets: Finding the Balance	**Howard Gruenspecht,** Deputy Administrator, EIA
North American Oil/Gas Supply/Demand and Pricing	**Mark Papa,** Partner, Riverstone Holdings LLC
North American Supply Chain Developments and Opportunities	**Robert Gwin,** EVP, Finance and CFO, Anadarko Petroleum Corporation
Well Performance and Reserve Changes in Unconventional Plays with Price Volatility	**Bill Von Gonten,** President, Owner, and Founder, W. D. Von Gonten & Co.

1:30 – 4:45 PM SESSION II: REGIONAL ISSUES

Will Gulf producers sustain production even if it results in significantly lower prices? Will large East Asian consuming nations continue to integrate forward into supply? What is the role of crude and condensate exports from North America? How will prices affect the short and long run prospects of international tight oil and gas development, Canadian oil sands, and deep water and arctic projects? What are the prospects for production in Mexico, Argentina, Columbia and Venezuela?

Global Energy Flows	**Jason Bordoff,** Director, Center on Global Energy Policy, Columbia University
Supply Costs and Exports	**Scott Sheffield,** Chairman and CEO, Pioneer Natural Resources
Latin America Supply Development	**Steve Crowell,** President and CEO, Pluspetrol
Africa/Middle East/Caribbean Challenges and Changes	**David Goldwyn,** President, Goldwyn Global Strategies

Thursday, June 11

9:00 – Noon SESSION III: NATURAL GAS

To what extent does foreign policy, as compared to domestic policy, affect domestic energy economics? Is the vision of a global gas economy any closer? If so, what are the global implications? What challenges and opportunities exist to encourage future substitution of natural gas for coal? How does this play into utility demand, LNG terminal readiness, the global LNG market, and market penetration for natural gas?

The Impact of Domestic Natural Gas on Global Standing and Security	**Paula Gant,** Deputy Assistant Secretary, Office of Oil and Natural Gas, DOE
Electricity Demand for Natural Gas	**Marc Manly,** EVP and President, Commercial Portfolio, Duke Energy

Drivers of Asian Demand	**Trevor Houser,** Partner, Rhodium Group, and Visiting Fellow, Peterson Institute for International Economics
U.S. LNG Exports	**Chad Zamarin,** President, Cheniere Energy

1:30 – 4:45 PM SESSION IV: ENVIRONMENTAL CHALLENGES

How will EPA's proposed methane rules impact the oil and gas industry? What types of viable policy changes are driven by a desire to reduce greenhouse gas emissions? How are local regulatory regimes affecting the industry at large? What are some other environmental challenges, such as water management and disposal, which may impact oil and gas development?

Proposed Methane Regulation	**Kyle Danish,** Partner, Van Ness Feldman LLP
Technology & Practices to Reduce Environmental Footprint	**Jean-François Poupeau,** EVP, Corporate Development and Communication, Schlumberger
Produced Water Management, Recycling, and Disposal	**Cal Cooper,** Director, Special Projects and Emerging Technology, Apache Corporation
Local Regulatory Challenges	**Roy Hartstein,** VP, Strategic Solutions, V+ Development Solutions, Southwestern Energy Company

Friday, June 12

8:30 – 11:00 AM SESSION V: EMERGING TRENDS

Can service costs and technology adapt to maintain production at prices less than 2011-2013? How will lower prices affect trends of global investment flows and potential consolidation? How are service companies rapidly adapting to provide more value and lower costs to operations through technology, innovation, integration, and supply chain efficiencies? How are new technology and data changing planning and investment? How can technical know-how, financial strength, and risk management position companies for growth?

Moderator:	**Janet Clark,** Member, Board of Directors, EOG Resources, Inc.
U.S. Regional Logistics, Regulatory Policy Evolution and Implications to U.S. Downstream Manufacturing	**Dan Romasko,** President and CEO, Motiva Enterprises LLC
Innovations in the Low-Price Environment	**Galen Cobb,** VP, Industry Relations, Halliburton
Innovation in Transportation	**Bill Reinert,** National Manager, ret., Toyota Motor Sales, Inc. U.S.A.
Technologies on the Horizon	**Adam Lasics,** Senior Director, Oil & Gas, GE Ventures

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