July 2016

GLOBAL FRAC'ING
CONFERENCE REPORT

STEPHEN V. ARBOGAST
Director, Kenan-Flagler Energy Center

VIKRAM RAO
Executive Director, Research Triangle Energy Consortium

KENAN-FLAGLER BUSINESS SCHOOL
The University of North Carolina at Chapel Hill

UNC KENAN-FLAGLER BUSINESS SCHOOL

ENERGY at KENAN-FLAGLER

UNC FRANK HAWKINS KENAN INSTITUTE OF PRIVATE ENTERPRISE

Table of Contents

- **Preface: Reasons for the Conference**
  Why U.S. Hydraulic Fracturing has been a Game-Changer
- **Executive Summary**
- **The Global Unconventional Resource Base – The Potential is There: Reserve Estimates and Relative Prospectivity by Location**
- **The Global Unconventional Supply Curve – Who is Closest to 'In the Money?'**
- **Above Ground Obstacles Beyond Geology and Logistics**
- **U.S. Frac'ing Cost/Production Gains – Can They be Exported?**
- **Global Frac'ing and the Environment – Risks, Management Practices, Costs**
- **Fiscal Regimes – Unsuitable Legacies and the Need for Customized Designs**
- **Additional Conference Observations, By Location**
- **Summary: What Has to Change for Global Frac'ing to be a Game-Changer**
- **Appendices:**
  1. **Conference Program**
  2. **U.S. Frac'ing Production Gains, Efficiency/Productivity Learning Curve**
  3. **Alberta Energy Regulator: Mandate, Rules, 'Area Regulatory Regime' pilot study**
  4. **Model Fiscal Regime for Unconventional Development**
  5. **Abbreviations**
  6. **About the Authors & Sponsors**

Global Frac'ing Conference – Conference Report

Preface

On April 1-2, 2016, the Energy Center at the Kenan-Flagler Business School, University of North Carolina at Chapel Hill convened a conference on **"*Global Frac'ing, What has to Change for it to be a Game Changer?"*** It was an invitation only event with attendance limited to industry experts, leading consultants and responsible government officials. Attendees and speakers came from the U.S., UK, Poland, Mexico and Canada.

The conference was convened for several reasons. First, the 'shale revolution' has delivered remarkable benefits to the U.S. economy, geopolitical security, and climate change efforts. Thus, the first question for the conference was whether nations outside the U.S. possess the potential to realize similar benefits.

Some non-U.S. locations have already seen efforts to exploit shale and 'tight' oil/gas resources. These have not led to anything resembling America's success. This realization led to a second set of questions for the conference. What are the principal barriers to unconventional oil and gas development by location? Can they be translated into differing cost estimates by location? Can these then produce a rough "Industry Supply Curve" showing which locations are more prospective as of now, and by how much? How different are such curves when they deal with natural gas as opposed to oil?

Similarly, published accounts provide little perspective on what was 'right' or favorable by location. Putting this in the form of a third question, the conference asked - what are the industry/regulatory-leading practices, in the US and elsewhere, that might hold lessons for other locations?

The dramatic decline in global oil and gas prices posed a final question. If hydraulic fracturing and unconventional development were not progressing when crude prices were $100/b in 2014, near term prospects must certainly be worse. Thus, the fourth and final question concerned what has to change for unconventional development to get 'into the money.'

This last question was served up with the knowledge that the oil and gas industries are cyclical. There is no time better to consider structural and regulatory reforms than at the trough. This allows changes to be in place to encourage a rapid industry response when conditions improve, as they inevitably do.

The conference speakers addressed these questions both globally and for six specific locations: Argentina, Alberta, China, Mexico, Poland and the United Kingdom.

This report summarizes the main points which emerged from the speaker presentations and subsequent discussion. It does not attempt to be a comprehensive treatment of Global Frac'ing. Rather, it raises these four sets of questions and presents the conclusions which developed. The Executive Summary provides an overview of these conclusions. The appendices share details on two matters much discussed – what would be a model regulatory regime for unconventional development, and what would constitute a model fiscal regime?

The Conference was conducted under Chatham House Rules. These dictate that while the information developed at the Conference can be disclosed, no attribution is to be made to any specific speaker or participant. Consistent with these rules, no attributions are made herein regarding the key findings, observations or conclusions, and no questions of this nature will be answered going forward.

Throughout this report the terms Frac'ing, Hydraulic Fracturing and Unconventional Development are used synonymously. Industry experts will tell you they are not exactly the same thing. Frac'ing is simply short for hydraulic fracturing. Hydraulic Fracturing injects large volumes of water with some chemicals under pressure to fracture the rock and induce artificial permeability. This is followed by the injection of "proppants" like sand to keep fracs from closing up. This is the core technique that has enabled the shale revolution to happen. Unconventional development is a broader term, covering everything beyond traditional drilling of wells, pumping and pressure maintenance. For this report, the terms mean the development of oil and gas trapped in shales or 'tight' rock formations, predominantly via drilling horizontal wells into these formations and then employing hydraulic fracturing. Another important unconventional resource, coal bed methane, was not covered in this conference.

We hope you find ***Global Frac'ing, What has to Change for it to be a Game Changer? – The Conference Report*** interesting and useful. As a prelude to the report itself, we now provide some perspective on the U.S. Shale Revolution as a Game Changer.

Stephen V. Arbogast
Vikram Rao
Authors

The Kenan-Flagler Energy Center
The Kenan Institute of Private Enterprise
Sponsors

Why Frac'ing has Been a U.S. Game-Changer

As an introduction to global frac'ing's potential, some perspective is provided by reviewing how it has changed the energy game in the United States.

Scarcity of supply was the dominant characteristic of the U.S. energy situation after 1970. In that year, the Texas Railroad Commission authorized all-out oil production. U.S. spare capacity was then a thing of the past. The ills that followed were many. OPEC gained the leverage to nationalize western concessions and embargo the U.S. during the 1973 Arab-Israeli War. Oil prices went up 300% in 1973, then tripled again in 1980. Gas lines, recession and inflation followed. From 1973- 2010, the U.S. and its NATO allies were exposed to price shocks and vulnerable to physical curtailments of supplies. In 2008, these consuming nations saw their economies battered by $145/b crude prices.

In that same year, U.S. oil production totaled less than 50% of oil demand. Nationwide gasoline prices averaged over $4/gallon. The National Petroleum Council pronounced that henceforth domestic natural gas supplies would be insufficient to satisfy demand. Just three years earlier a hurricane sent natural gas prices soaring to $15/MBTUs. Plans for LNG import terminals began to take shape. Peak Oil theorists reemerged, asserting that this time, truly, the world could only look forward to declining production. Deeply concerned, Congress passed the Energy Independence and Security Act of 2007, requiring the addition of 36 billion gallons of ethanol and advanced biofuels to the gasoline pool by 2022.

This was the state of U.S. energy prior to frac'ing's breakthrough: physically vulnerable, threatened in terms of national security, its diplomacy hampered by the threat of retaliation, its economy exposed to sudden price spikes, inflation and recession. Going forward, it looked like more of the same, or worse.

Horizontal wells stimulated by hydraulic fracturing fundamentally changed all of this for the U.S. By opening up supplies stored in ultra-low permeability shale rock, frac'ing transformed constrained supply into unexpected abundance. The U.S. now looks forward to adequate natural gas supplies as far as the eye can see. It now builds LNG export terminals. Domestic crude oil and condensate production has doubled to over 10 MB/D. The U.S. still imports 40% of needed supply, but all of this can come from Western Hemisphere suppliers. All new U.S. supplies are economically feasible at prices below $100/b for oil and $4 MBTU for gas.

This altered situation produces the following benefits for the U.S. economy, national security and its climate change situation:

- **The U.S. is no longer exposed to physical boycott** by Middle East oil producers. The U.S. can source all needed imports from Canada, Mexico and Venezuela
- **Frac'ing has put a cap on oil price shocks**. Should oil prices rise towards $100/b, millions of barrels/day of added supply should come forth from U.S. frac'ing. Because of frac'ing's 'short cycle,' i.e. it's much faster development time vs. offshore or tar sands, new supply should materialize more quickly, both containing and moderating price cycles.
- **The U.S. has the lowest cost energy prices of any OECD nation.** America has $2 MBTU natural gas versus $6-12 MBTU everywhere else. Its large domestic oil production reaches

market through the world's most efficient refining and distribution systems, such that American consumers pay less for gasoline and diesel.

- **Abundant natural gas has allowed a massive transition away from coal in electricity generation, with big corresponding reductions in Greenhouse Gas (GHG) emissions.** U.S. GHG emissions are now below 1995 levels because of this switch, and this has been accomplished without materially increasing electricity prices.
- **Plentiful U.S. natural gas facilitates the development and integration of renewable power into the electricity grid.** This is so for several reasons:
    1. Natural gas plants start up quickly versus coal or nuclear, and thus provide the backup needed due to renewable power's supply unpredictability
    2. The declining price of natural gas plus its abundant availability have allowed renewables to be subsidized while they get to 'scale' without requiring consumers to pay higher prices to fund the subsidies
    3. Natural gas provides a cost-effective, lower carbon alternative to coal over the decades to come, while the ultimate potential of renewables + storage + demand management is determined. Gas buys time for us to determine the optimal mix of hydrocarbons and renewables.
- **Shale oil and natural gas have provided U.S. manufacturing with a competitive cost advantage.** Energy intensive manufacturing in the U.S. enjoys a significant advantage versus Europe, Japan or China, all of who depend upon imported oil and LNG for marginal supplies. This is especially obvious in the refining and chemical industries, where new U.S. capacity is being built and exports are at record levels.
- **U.S. diplomacy in the Middle East is now free from the threat of physical retaliation and has less to fear from price shocks. The U.S. is again in a position to help allies with long term LNG supplies and even emergency refined product shipments.** The US is now in a position to seek a sharing of the cost of policing the Strait of Hormuz because that no longer is a strategic water way for the US.

This list of benefits is impressive, even staggering, considering where the U.S. was only eight years ago. The next obvious question becomes whether a similar list of benefits could result from extending the U.S. frac'ing revolution around the globe. Could, for example:

- **Global oil & gas price cycles become even more moderate** as new unconventional supplies enter from Argentina, Canada, Mexico, and Europe?
- **China become less reliant on coal** and imported Middle East oil, bolstering its ability to moderate GHG emissions and reducing its exposure to supply interruption?
- **Poland, the Baltic States, and all of Eastern Europe become less exposed to energy blackmail** by Russia and less reliant on using coal for electric power?
- **The U.K. offset declining North Sea natural gas with onshore frac'ing supplies**, thus preventing its electricity and manufacturing from bearing the cost of imported LNG?
- **Mexico replace declining conventional oil production** and part of imported natural gas with new unconventional production, thus **saving the Federal budget** from major funding stress?

- **Argentina develop natural gas sufficient to end unreliable imports from Bolivia or high priced LNG supplies**, thus combating inflation and improving economic competitiveness?
- **Canada replace declining conventional oil production** with light shale oil that can balance its heavy oil production and provide diluents for transport to the U.S.?

These questions illustrate the potential of global frac'ing. If even some of these results could materialize, global frac'ing would qualify as a game-changer. The purpose of the conference was to explore what would have to change to unlock this potential. The report that follows provides the most up-to-date answers available to these questions.

Given frac'ing's impressive list of U.S. benefits, another question naturally arises - why has it aroused such fervent opposition in some quarters? How is it that development in Pennsylvania's Marcellus formation transformed that state's economic outlook even as 'No Fracking' signs dotted lawns in adjacent N.Y. State?

A portion of this opposition relates to frac'ing's undeniable environmental and community impacts, especially in the initial development stage. (Once a well is producing, its footprint reduces to a much smaller impact) These concerns are addressed in Section V below.

The more concerning form of opposition is rooted in a sincere conviction that climate change poses such an existential risk that reliance on hydrocarbons has to be fought in an all-out fashion. To people with this conviction, only a wholehearted and immediate conversion to renewable power will stave off disaster. For them, the shale revolution is profoundly unwelcome. They see in it the threat of extending reliance on hydrocarbons, of seducing consumers with cheap energy, and of inevitably bringing about the climate events they are dedicated to forestalling.

These climate-change maximalists are sincere but less than honest about their policy agenda. Stripped down, they are willing to impose huge current costs on populations in terms of higher energy prices, less development, and greater unemployment. They also are willing to take the risk of returning leverage to a handful of fossil fuel exporting countries. Strip frac'ing supplies from the energy mix, and unless renewables achieve growth and penetration scarcely imaginable, we are back to the supply constrained world where Russia, Saudi Arabia and Venezuela set the energy agenda.

Most important, climate-change maximalists deny the substantial synergy that exists between unconventional development and a sound climate agenda. Using natural gas to take coal out of electricity generation has proven to be the most impactful climate change step achieved thus far. Why should this not be extended globally? Natural gas also has potential to replace diesel supplies in transportation. Why not welcome these steps, especially at a time when the ultimate potential of wind and solar to provide all the power needed has yet to be proven?

On behalf then of all the conference participants we ask that you come to this report with an open mind. This conference was structured to bring forth the most objective and candid discussion possible. Global frac'ing is a potential and very positive game-changer, but as this candid discussion showed, much has to change for that to happen.

Global Frac'ing – What Has to Change for It to Be a Game Changer?
UNC Kenan-Flagler Conference, April 1-2, 2016

Executive Summary

Overall Findings

- Presently, no location outside the United States Is 'in the money' for the production of oil via hydraulic fracturing. **Certain locations, notably Argentina and the U.K., could be 'in the money' today as regards the production of natural gas from unconventional resource plays.** This disparity is due to international natural gas fetching higher prices because they are pegged to LNG import prices, that natural gas can play a positive role in climate-change policies, and that international issues of gas supply security can be acute.
- **Argentina and the U.K. will thus be 'precedent-setting locations.'** Argentina will demonstrate whether a land richly-endowed with unconventional resources but with a checkered political risk history can provide investors with an attractive, sustainable development framework. The U.K. will demonstrate whether frac'ing can be rendered politically sustainable in developed countries where community opposition and environmental sensitivities present barriers.
- A wide variety of geologic and 'above ground' issues, compounded by current low prices, is responsible for the limited unconventional exploration activity to date. These barriers will not be overcome by a simple migration of improved U.S. techniques and technologies. Some of recent U.S. gains are cyclical in nature and others rely on a highly competitive services industry. Comparable industry structures for frac'ing do not exist outside the U.S. and possibly Canada. **The conference estimated that only 10-20% of recent U.S. cost economies are likely 'exportable' and sustainable. Non-U.S. locations will thus have to pay more attention to their regulatory and fiscal regimes if they are to overcome a less favorable industry cost structure.**
- **As a general rule, non-U.S. locations have not designed either their regulatory or their fiscal regimes to incentivize unconventional development.** Existing regimes do not take into account frac'ing's unique characteristics, and thus present unintended barriers.
- **More customized regulatory and fiscal regimes would help overcome another barrier, the lack of exploration data in many prospective locations**. Countries like the U.K., Poland and Mexico have interesting shale basins, but have attracted little or no drilling activity to date. What data do exist are often closely held or hard to access. This lack of data available to new players raises their exploration risk and diverts them toward other locations. To overcome this barrier, a country can lay out regulatory and fiscal regimes geared towards frac'ing. Doing so differentiates that country in a favorable way, promises investors reasonable land access and tax treatment, and ultimately will get drilling going sooner than in other locations.
- Certain frac'ing operating characteristics are especially relevant to the crafting of more customized regulatory and fiscal regimes. **Land access is a major issue outside the U.S.** Frac'ing involves onshore drilling. Its activities have visual and auditory impacts on local communities. Frac'ing uses large amounts of water, raising concerns about consumption, contamination and waste water disposal. These aspects can easily lead to local opposition to drilling, even though all of these issues have proved manageable in the U.S. **Putting in place upfront a regulatory regime customized for frac'ing-type operations is thus essential to reassuring local communities on these issues.** This regime should draw upon the many lessons-learned in the

U.S. It also should provide a form of 'one-stop' approvals for exploitation licenses. **The Alberta Energy Regulator has pioneered this form of comprehensive, yet efficient regulatory regime.**

- **Local communities also need to see fiscal incentives to compensate for the less desirable impacts of unconventional development.** This is a special challenge outside of the U.S., where mineral rights often belong to the central government rather than private landowners or local authorities. **The U.K. is presently showing the way on devolving central government taxes via returning business taxes and impact fees to local communities**.
- **Certain frac'ing characteristics are also relevant to the design of fiscal regimes**. Frac'ing wells do not produce especially large volumes per well, and initial surge production declines sharply within a year. This profile requires operators to undertake continuous and intensive drilling in order to sustain an aggregate level of production that can support logistical infrastructure**. If a developer cannot see a path to reaching 'field drilling intensity,' it will not commit the funds necessary to provide for infrastructure, and the field will not be developed to potential.**
- **Frac'ing fiscal regimes thus must incentivize continuous and intensive drilling during the field and infrastructure development stage**. The overall tax burden should be kept light during this period. Royalties should be avoided or minimized, as these are based on physical production rather than economics. An income tax structure should instead be used. Tax rates can increase once the field + infrastructure is developed, but should still be kept lower than for conventional or offshore production. Unconventional resources are a marginal source of supply. As such they are especially price sensitive. Tax rates thus can be allowed to vary upward if prices exceed expectations, but the structure should be kept 'dynamic,' i.e. rates should adjust down if prices fall below agreed thresholds. Otherwise, frac'ing, which is easy to stop, will cease and government take will decline precipitously.

Specific Findings*: Global Unconventional Supply Curve*

- **A rough global unconventional natural gas supply curve appears as follows**: Alberta (lowest unit costs for natural gas), followed by Argentina/ U.K., Mexico, Poland (mid-range on costs and potential, hampered by lack of information due to limited drilling) / China (high cost due to complex geology, wide variety of above-ground obstacles).
- Some locations not discussed at the conference, e.g. Saudi Arabia, Australia, Tunisia, Russia and Algeria could be in the low cost category, while others like South Africa and Ukraine would likely be mid-range
- **Global frac'ing for oil is 'out of the money' at $40/b crude prices** and faces a wide variety of obstacles that vary in importance by location.
- **Unconventional development of natural gas reserves is closer to being 'in the money'** at all locations not contiguous with the United States, due to LNG import-parity prices much higher than domestic US natural gas prices.
- Conversely, **development of the substantial natural gas resources in Alberta and northern Mexico will be retarded by the abundant lower 48 US gas production** and corresponding low prices. Given market fundamentals, shale oil development is more likely to proceed first in those two locations.
- Judging from the behavior of international companies, **today only Argentina gas seems within striking distance of becoming commercial.** Multiple companies have continued small scale operations there or maneuvered to acquire acreage. The combination of Vaca Muerta resource quality, established infrastructure and 'new gas' incentive pricing is responsible for this outcome. At the other end of the spectrum, **major firms have either refrained from entering**

Chinese unconventional development or in Shell's case, announced their pullout. In April 2016 BP did announce a China shale gas deal as a non-operating partner, possibly on its own merits or possibly as part of a broader global agenda.

- Costs mentioned are for steady state activity. Initially costs will be high in part due to high service company prices (due to Big Three having most of the share) and being early on the learning curve of the prospect.

<u>Prospectivity of Unconventional Resources</u>

- **It begins with the rock and in many locations is mostly about the rock**. While geological arguments dictate that shale resources ought to be ubiquitous, specific location characteristics dictate prospectivity. The key considerations are Total Organic Carbon (TOC), which needs to be over 2%, suitability of the mineralogy to enable fracturing (clay less than 50%) and spatial distribution of the high quality rock. Argentina's Vaca Muerta is by far the most promising of the plays abroad. Poland is hampered by higher clay content and greater reservoir depth. Complex folding and faulting in China's Szechuan province hampers the drilling of precise horizontal wells that access the target reservoir intervals.
- **Limited information is a major barrier to assessing prospectivity in certain locations**. Few wells have been drilled in the unconventional resource formations in the U.K., Poland and northern Mexico. This lack of information presents a 'Catch 22' barrier, with firms reluctant to undertake exploration risk at low prices when that risk is amplified by a lack of data from earlier drilling
- **Above ground barriers are formidable**, but vary by location. Density of local population is a major barrier in the U.K. and China. This condition manifests itself as organized political opposition in the U.K. In China, the population density and agricultural intensity are such that finding locations to drill wells can be challenging; despite government-organized compensation, individual communities may have additional requests and concerns that can impact operations. Good operating practice and safety standards may require a learning process in Chinese operations. In northern Mexico, the presence of local drug gangs creates physical security issues as yet unaddressed by the Federal government.
- **Mineral rights residing in the State's control** creates a major community support problem in many locations. Local communities often control land access and local populations have various ways to impede exploratory drilling. The impacts of unconventional development are visual and can be disruptive, e.g. noise, light, traffic, changed landscapes, and battered roads. In more affluent locations, the asymmetry of all negative front-end impacts versus local benefits makes local communities receptive to environmental and climate arguments intended to achieve de-facto development moratoriums. This is a special problem in the U.K. and possibly Poland.
- **Argentina's above-ground barriers are altogether of another nature – political risk**. The country has a well-earned reputation for repeated and massive economic intervention and contract repudiation. Investors repeatedly find themselves dealing with an overvalued currency inflating local costs, foreign exchange restrictions and/or multiple exchange rates, fiscal revisions and the voiding of contracts. While the new Macri government seems well-disposed towards private sector development, investors have legitimate questions about the sustainability of any favorable policy changes. Argentina has a strong 'default position' of state-led, SOE managed development that could return as soon as the next presidential election.
- As noted above, **most global locations lack the competitive service company sector** that has fathered much cost reduction in the U.S. In many locations, service company presence consists only of the "Big three." In China, it means dealing with the captive service company of an SOE

partner. Contiguous Alberta and Mexico could be exceptions if economic prospects were not hampered by U.S. gas prices. Weaker local currencies vs. $US may offset part of this disadvantage, especially in Argentina.

Export of U.S. 'Leading Industry Practices' & Lessons Learned - Drilling Operations & Costs

- **The US shale gas/oil experience provides a useful set of lessons and leading practices** that could enable non-US locations to facilitate unconventional development with more efficiency and fewer unintended consequences. This includes features such as pad drilling, re-using flowback water and water treatment and disposal.
- **A portion of recent U.S. productivity gains is exportable to foreign locations**. These exportable gains include: 1) pad drilling to reduce physical footprint and operating redundancies; 2) mobile drilling rigs that reduce the number of rigs developing a field and time lost to demobilization/remobilization; 3) longer horizontal wells with more fractures, improving productivity per well; 4) faster drills and drilling practices that reduce rig lease days/completion; and the application of geophysical sciences to target higher productivity well sites. To date, the evidence from 're-fracturing' wells is inconclusive as to benefits but this is one of the areas of innovation that, when perfected, will be transferable. This is in part due to the fact that it is the service companies who will be making the advances.
- **That portion of U.S. gains related to a) drilling rig costs; b) costs for frac'ing materials, e.g. proppants, chemicals; and c) labor costs, probably isn't exportable due to it being a function of competitive U.S. markets, the U.S. industry down-cycle, or both.**
- **No ready solution exists for the high service costs in most countries**. Certainly an early target ought to be plans to indigenize materials and labor.

Export of U.S. 'Leading Industry Practices' & Lessons Learned - Environmental

- US experience suggests that **a full set of environmental rules and monitoring mechanisms should be in place before drilling begins**. Such rules and mechanisms, adapted from North American experience, can forestall major early environmental impacts that would undermine community support for development.
- US experience also suggests that **most environmental issues** associated with unconventional development **are either not material** (contamination leaks from fracturing at depth into groundwater) **or manageable by good operator practices** (e.g. well casing integrity, waste water disposal). However, good practices, such as seismic work before drilling disposal wells, cost money and require effort. For non-US frac'ing that struggles to get into the money, the temptation to take shortcuts on good practices will exist.
- Fugitive natural gas emissions are a special example of where the study of US lessons learned can prove valuable**. Recent studies have shown that most US natural gas emissions are from existing infrastructure rather than the drilling pads themselves.** This infrastructure has been shown to be very leaky, often due to valve designs that inherently leak. **Foreign locations can avoid this problem by requiring new infrastructure to employ alternate designs**, such as low bleed valves or even designs using compressed air.
- **Associated gas from shale oil development presents a special problem.** Fields developed for their oil potential may lack infrastructure to deliver associated gas to market. The typical solution then is flaring. This wastes a valuable resource and attracts environmental/climate opposition by putting CO2 into the atmosphere. Yet, when unconventional development is

struggling to be commercial, economics typically favor flaring versus reinjection or pipeline construction, in part because the widely distributed well pads have low median volumes of associated gas. There is no silver bullet solution here, but **regulatory and fiscal regimes should require and incentivize plans that envision phase-out of gas flaring within reasonable timeframes, as in North Dakota today (see discussion on area regulatory/fiscal regimes).**

- In the area of air emissions **the US is on a fast track for developing detection schemes for methane and other organics.** Foreign entities ought to watch that space carefully to take full advantage of early adoption. The truism holds: if you cannot detect and measure, you cannot control, whether through best practices or regulations.
- **Baseline testing of potential pollutants, both water and air borne, is important to forestall arguments and increase citizen confidence.** The selection of analytes, spatial distribution and so forth ought to be from the best existing regulations.
- New areas ought to pick the best of available legislation in North American states and Canadian provinces. **Alberta's regulatory and fiscal regimes seem to attract wide support for their effective balance of development incentives and environmental sensitivities.**
- **No good system exists for efficiently searching environmental data and regulatory systems, and especially for cross matching with local specifics. An enabling mechanism would be of value, possibly jointly funded by governments.**

Export of U.S. 'Leading Industry Practices' & Lessons Learned – Fiscal Regimes

- **Many fiscal regimes are ill suited to support unconventional development.** Most have been crafted for conventional onshore or offshore development, and do not take into account the different production profiles and other challenges associated with exploiting unconventional resources. More customized fiscal regimes/terms geared to unconventional 'plays' are needed.
- **The U.S. was fortunate to have an Oil & Gas fiscal regime quite favorable to small volume producers.** A legacy of the 1950s concerns for 'stripper well' domestic production, the U.S. affords producers a Tax/Royalty regime with a 35% flat income tax rate and generous allowances for reserves depletion and accelerated depreciation schedules. Today these conditions allow U.S. producers to keep most of the price upside and shield revenue from taxes during fracking's initial production surge. This allows U.S. producers to generate early cash flows that fund ongoing drilling. US unconventional production was also the beneficiary of existing transportation and processing infrastructure (in many cases), a competitive service industry, and access to deep and liquid product markets. High U.S. royalty rates work in the other direction, but were generally overcome by the suite of other U.S. fiscal advantages. **International fiscal terms will likely have to be better than those in the US to compensate for the lack of these features.**
- **An economic characteristic of unconventional development is the need to reach 'field drilling intensity', i.e. a level of activity that produces enough sustained volume and associated revenues to support needed infrastructure**. Reaching this activity level is needed to achieve commercial development of the field; sustained volume efficiently transported to market then produces government-take over time. A model fiscal regime would target and incentivize reaching 'field drilling intensity.'
- **To customize an unconventional fiscal regime, define a development area and a level of sustained production necessary to support 'to-market infrastructure.' Early production and the ramp-up to 'field drilling intensity' should then be lightly taxed or not taxed at all. Royalties based on revenues are counterproductive and should be minimized or avoided**.

Normal taxes would be triggered by the attainment of sustained volume. From there, tax rates would either be flat or have a modest price escalator. **This form of fiscal regime recognizes that unconventional development is likely the 'marginal source' of global production**. As such, it needs a more favorable tax regime to incentivize investors to take the risk of developing relatively high cost reserves and maintaining production levels during price downturns. The fiscal regime should also adjust rates down under low prices to avoid cessation of frac'ing.

- **It is important that unconventional fiscal regimes address the community support problem cited above.** This can be done by providing for 'up-front' money to be injected into the local community as 'impact fees,' royalty advances or some similar mechanism. Here it is important that the community see the visible effect of such funds, as opposed to their disappearing into municipal budget deficits**. UK proposed policy in this space appears to be right on track.**
- **Customized fiscal regimes for unconventionals can usefully be integrated with 'Area' regulatory regimes, such as those now being developed by the Alberta Energy Regulator.** These regimes set environmental rules for a defined area, taking into account the particular characteristics, environmental risks and economics of said area. Once the regulatory regime has defined 'areas,' a fiscal regime can attach itself to such areas by applying general principals with local customization.

The Global Unconventional Resource Base – The Potential is There

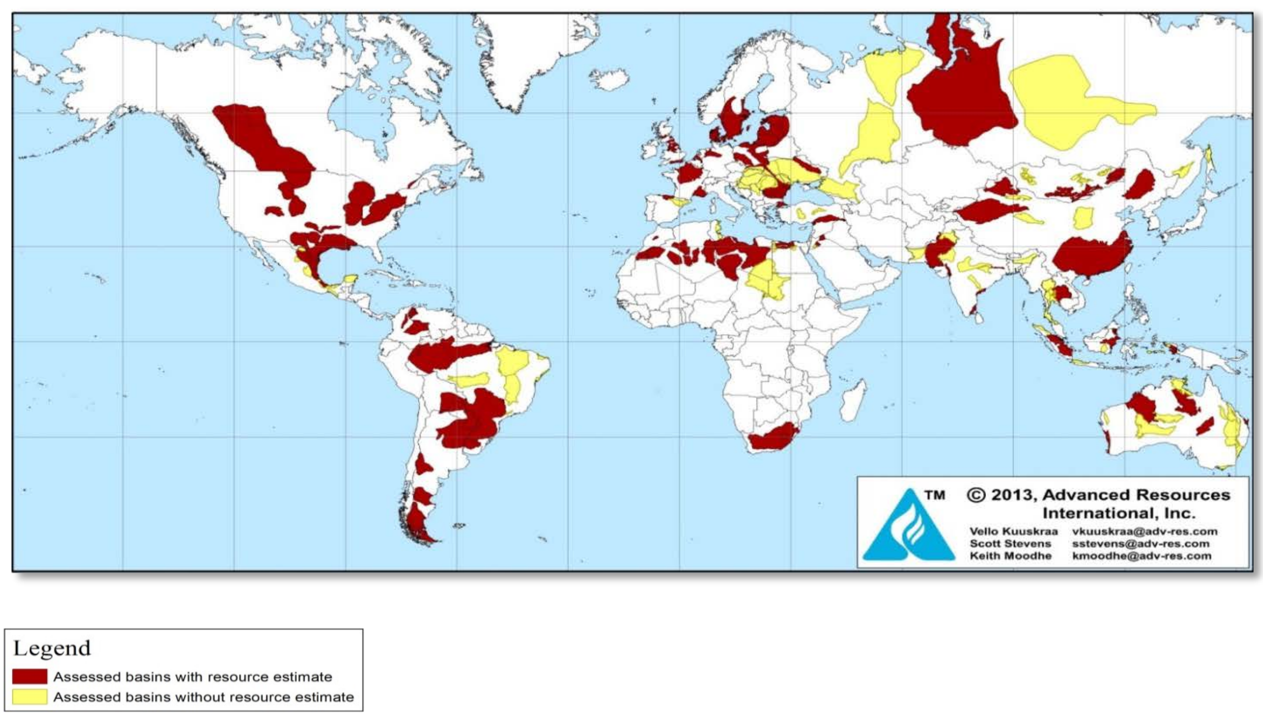
Questions: How extensive is the global unconventional resource base? Is it ample enough to support an energy game change, as in transforming a constrained hydrocarbon supply environment to a well-supplied condition? Are there meaningful differences in quality and difficulty of access when compared with U.S. experience? If so, how do these materialize by location and by oil versus natural gas?

The global unconventional resource base is ample enough to transform a constrained hydrocarbon supply situation to a well-supplied condition.

This however, not only involves the total estimated size of this resource base but also its ability to provide growing marginal supplies that supplement existing conventional production. In a world where, for example, annual oil demand may grow by 1-2 MB/D, the non-U.S. unconventional resource base clearly has the potential to add that amount to global supplies for 1-2 decades to come.

For perspective, consider that the U.S. has exploited an unconventional resource base of ~67 billion barrels to add 4 MB/D to oil production. Reports by Advanced Resources International (ARI) estimate the non-U.S. unconventional oil resource base to be about 340 billion barrels. Said differently, developing these resources would equate to adding 1 ½ Saudi Arabias to global proved oil reserves.

Supply prospects in natural gas are even more favorable. For gas, the non-U.S. resource base approximates 7,000 TCF, approximately the equivalent of adding 8 South Pars fields to global supply. Annual demand growth for natural gas amounts to ~6 BCF/D or 2.2 TCF/Yr. This technically recoverable unconventional resource base clearly has the potential to supply this level of incremental volume for decades to come. In fact, unconventional resources will only have to supplement the conventional gas reserves, which also have the potential to meet growing demand volumes. Exhibit 1 shows the location of the major unconventional basins.



We conclude here that the 'game-change' prospects for unconventional oil and natural gas are different. Unconventional oil prospects promise relief from supply constraints for a significant, but still limited time frame. That is not a game changer. Global unconventional natural gas supplies promise ample supplies well into the next century. For gas, unconventional development is a game changer.

The abundance of unconventional natural gas resources means it can provide a firm basis for public policy. Deliberate policies directing demand into gas and away from competing fuels like coal can count on doing so without triggering supply shocks and price spikes. This is not to say that supply constraints and rising prices can't occur. It is to say that global natural gas supplies should be able to respond fairly quickly to unanticipated demand, lessening the severity and duration of any shocks.

The distribution of unconventional oil and gas reserves is also different by location. Outside the U.S., oil and gas both tend to cluster among 4-5 other countries, as is illustrated by Exhibit 2:

Technically Recoverable Shale Gas Resources* (Tcf)	
1. U.S. (ARI 2016 est.)	1,648
2. China	1,115
3. Argentina	802
4. Algeria	707
5. Canada	573
6. Mexico	545
7. Australia	437
8. South Africa	390
9. Russia	285
10. Brazil	245
11. Others*	1,859
TOTAL	**8,606**

Technically Recoverable Shale Oil Resources* (Billion Barrels)	
1. Russia	75
2. U.S. (ARI 2016 est.)**	67
3. China	32
4. Argentina	27
5. Libya	26
6. UAE*	23
7. Australia	18
8. Chad*	16
9. Venzuela	13
10. Mexico	13
11. Others*	100
TOTAL	**410**

There are several things to notice about this ARI chart. First, on a BTU-equivalent basis there is almost four times as much unconventional natural gas as there is shale oil. Australia, ranked seventh in shale gas with 437 TCF, has a bigger resource on BTU basis than Russia's 75 billion shale oil barrels. Such data reconfirms and emphasizes both the ample nature and wide distribution of unconventional global gas.

Second, a small cluster of nations accounts for a large percentage of these unconventional resources. The U.S. China, Argentina, Algeria, Canada and Mexico account for two thirds of global shale gas resources. Russia, the U.S., China, Argentina and Mexico account for over half of global shale oil. Take note of the non-U.S. countries on both lists. These are China, Argentina and Mexico. These countries show both oil and unconventional gas potential. They also have strong incentives to develop these resources. All, for example, are net importers of natural gas.

China and Mexico would appear to have especially great political and macro-economic incentives to develop their reserves. China's huge economy is greatly dependent on vulnerable imported energy from the Middle East. China's reliance on coal-based electric power also inflicts it with a serious pollution and climate-change challenge. Leaders in methanol substitution of gasoline, they are forced to use coal as the raw material. Developing indigenous shale oil and gas works on all of these exposures. Mexico's conventional oil production is in serious decline, and it imports substantial amounts of U.S. natural gas. Reliable and affordable electric power is a constraint on economic growth. About 1/3 of Mexico's federal budget is funded by the nation's oil production. With conventional production in decline, Mexico's choice is to find replacement supplies or face serious fiscal constraints.

Some countries not on the above chart do possess unconventional resources and major pressures to develop them. Most of Eastern Europe, but especially Poland and the Ukraine, confront expensive and unreliable gas supplies from Gazprom of Russia. The U.K., having shut down its coal industry and eliminated coal-fired electricity generation, now faces rapidly declining North Sea gas supplies. These countries will be pacesetters for whether Europe can somehow reconcile its energy needs with unconventional development that is opposed by an activist faction of its population.

In sum, the technically recoverable shale gas resources may be huge, but will depend on a few non-US locations to show the way. As will be seen shortly, the barriers to developing these resources vary greatly by location. This means it will probably take more than one non-U.S. location successfully developing its unconventional reserves to provide a comprehensive set of solutions which other nations can then replicate. Argentina and the U.K. will be especially important 'pacesetter' nations.

Some caveats are in order. First, the above reserve estimates are likely to change, mostly in the direction of getting bigger. Some countries, notably Saudi Arabia, are missing from the picture. Vast areas of global shale basins have hardly been explored. Experience to date suggests that as development grows and techniques advance, increasing shale oil and gas prospects become known and 'technically recoverable.' There will also be subtractions in particular locations as plays turn out to be missing one or more of the attributes ultimately required.

Of course the hard reality is that the term 'technically recoverable' dodges the all-important question of economics. Can these resources be produced economically at anything like current prices? If not, how much do prices have to adjust and how much do conditions 'on the ground' have to change to put these unconventional reserves 'in the money.'

Answering these questions will be the focus of the remainder of this report. A portion of the answer remains with the composition and quality of the resources themselves. Simply put, 'how good are the rocks,' by location?

The conference did not undertake an exhaustive evaluation of resource quality, but some indicative information was provided.

In terms of resource quality, Argentina appears to have the 'best rocks' outside of the U.S. Exhibit 3 below provides some illustrative data from the Middle Magdalena valley basin.

Exhibit 3

Prospective Area	2390 miles
Physical extent – organically rich	1000 feet
Net pay zone	300 feet
Total Organic Content	5 %
Depth – range	3300-16400 feet
Average	8000-10000 feet
Clay content	Low

Argentina's comparative advantage becomes clearer in this comparison with other leading non-US unconventional basins. These are listed in order of declining relative attractiveness.

Exhibit 4

Location:	***Mexico Burgos***	***China Longmaxi***	***Poland Baltic***
Prospective Area	10,000 miles	10,070	2070-5680
Physical extent – organically rich	200 feet	1000	820
Net pay zone	160 feet	400	451
Total Organic Content	5 %	3.2%	3.9%
Depth – range	4000-16400 feet	9000-15,000	7,000-16,000
Average	7500 feet	11,500	10,000-12,500
Clay content	Low	Low	Moderate

These data don't capture the relative complexity of these geologic formations. That will be touched on in the next section. Generally speaking however, as explorers move away from the Argentine basins, they are required to drill deeper to reach pay zones which are either less thick or less organically rich. That means more drilling costs for less production, which implies higher finding and development costs.

Just looking at the rocks, one can infer a rough 'Industry Supply Curve'. However, many factors, including above-ground elements, influence unconventional unit finding/development costs. In our next section, we add some of those factors, specifically industry structure and infrastructure to geologic prospectivity, and posit a preliminary Unconventional Industry Supply Curve.

The Global Unconventional Supply Curve – Who is Closest to 'In the Money?'

Questions: Just looking at geologic factors, drilling costs and logistics, what is the composition and cost structure of a global unconventional supply curve? Are any locations "in the money" at current oil/gas prices ($50/b Brent, $6-8 MBTU landed LNG). Does this economic outlook vary by oil vs. gas?

The previous section set up a rough global supply curve based on geologic factors. Argentina was the lowest cost location followed by, in ascending order, Mexico, U.K., Poland and China. Alberta's geology was not reviewed at the conference, but for gas its prospectivity ranks with or just behind Argentina. As noted, other countries not covered, such as Algeria for gas and Saudi Arabia for unconventional oil, would probably rank with or ahead of Argentina as low cost unconventional producers.

Note here that the industry supply curve is a unit cost curve. This measures total production costs for a unit of production and thus reflects not only finding and drilling costs plus delivery to market, but also the volume produced. Thus, very productive rocks can offset higher costs from depth or complexity by yielding more volume per costs incurred.

It should be stated that today no location outside North America is "in the money" for unconventional oil. This is a matter of simple inference. With oil prices in the $30-45/b range, U.S. operators laid down rigs and cut production. Drilled wells were left uncompleted. A recent rebound to the $50/b has sparked some completions, but has barely started to reverse the rig count slide. If these price levels are not sufficient to encourage US investors to drill on already secured lease holds, they clearly are not sufficient to incentivize global investors to undertake the more costly process of acquiring acreage, conducting seismic acquisition, and drilling exploratory wells, all to find out if going into production mode is likely to make money. All this comes before considering the drilling, infrastructure, regulatory and fiscal disadvantages sported by non-North American locations, about which more will be said below.

The situation is more complicated and promising for natural gas. The complication lies in the fact that, gas is not a global commodity. There is no global price. Rather regional prices prevail, driven by vast differences in logistics. U.S. consumers enjoy abundant supplies delivered by pipeline. Wholesale natural gas here barely registers over $2 MBTU. Markets in Europe, China, Japan and India are dependent on imports from distant supply sources. Often the marginal supplies are LNG. These huge markets pay landed LNG costs of $6-8 MBTU or more. Moreover, most contracts are still indexed to crude oil. As oil rebounds towards $50/b, LNG prices will also rise irrespective of what happens with U.S. Henry Hub gas prices. Some governments with LNG imports, like Argentina, India and China, use tiered price structures to incentivize domestic production. Argentina, for example, pays $2 MBTU for 'old gas' but $6-7 MBTU for newly developed supply. All of this means that price signals for global unconventional natural gas look more robust than for oil, and may look even better in the near term.

We now add drilling costs and logistics to geologic prospectivity to refine the global supply curve. Drilling costs are largely a function of the remoteness of the location in question. They also are greatly influenced by the degree of competition in oil field services. U.S. drilling costs recently declined in spectacular fashion in response to plummeting hydrocarbon prices. These lower prices set off a frenzy of cost cutting that took advantage of a very competitive oil field services industry. Competition is much more limited outside the U.S. In places like Argentina, it is largely limited to the "Big three' service firms, i.e. Schlumberger, Halliburton and Baker Hughes. Europe offers some local oil field service firms, but these have done little hydraulic fracturing and face a steep learning curve. The situation is somewhat similar in China, and is compounded by the fact that local service companies have strong ties to the big State Owned Enterprises (SOEs). These ties tend to mute rather than foster price competition.

Two advantaged non-U.S. locations are Canada and Mexico. Being contiguous to the U.S., they have access to services firms beyond the 'Big Three.' They also benefit from the fact that a portion of their unconventional reserves are extensions of basins already developed in the U.S.

The conference provided some indicative gross Finding & Development Costs (F&D). These were presented both in terms of $M per well, and unit costs **ex-royalties, taxes and return on capital.**

Exhibit 5

Country	***$M/Well***	***$ F&D MCF gas***	***$F&D BOE oil***
*China**	*$12+*	*$2-3*	
Argentina	*$10-12*	*$1-2*	*$16-18*
*Mexico***	*$12-15*	*$2.5-3*	*$30-40*
Poland	*$10-13*	*$3-3.5*	

** Reflects China's 'very best basin' Longmaxi in Sichuan Province*

** Based on very few wells; to date only 35 wells drilled over time, all by Pemex*

It is worth noting here the differences in drilling experience by location. Unconventional development has a significant learning curve. For example, wells operating in the U.S. Barnett shale averaged an initial production of ~800 cu.ft./day in 2003. By 2015 that average IP was approaching 2000 cu.ft./day, and many individual wells were yielding 4000-5000 cu.ft./day. Put simply, knowing where to drill and how to frack a particular field can more than double production per well.

The chart above reflects different places on this learning curve. Argentina is probably the most advanced. In the Neuquen basin alone, 424 shale wells are 'on production' with 173 of those wells drilled in 2015. That basin is now producing ~51 kbd BOE from the Chevron/YPF joint venture. Elsewhere in the basin another 240 MCFD of tight gas is in production. The China data reflects Sinopec producing 500 MCFD from 140 wells at 2015 YE and PetroChina producing 150 MCFD from 47 wells.

Conversely, the Mexico and Poland estimates reflect very limited drilling done mostly years ago. The good news for these countries is that there appears to be ample room to improve by moving along the learning curve. This is especially the case for Mexico, with its access to U.S. oil field services and its ability to develop an extension of the Eagle Ford basin. Poland's improvement potential is more uncertain. Poland is in a very early learning curve stage, having drilled only 12 horizontal frac'ing wells; it also lacks access to competitive oil field services. The U.K. hardly registers on the unconventional learning curve, due to its inability to encourage or support firms to complete any exploration wells. To date a total of less than 10 unconventional wells have been attempted in the U.K. and the number completed is a matter of conjecture.

Logistics is a big differentiator by location. Again Argentina is advantaged. The Neuquen basin is a historic oil and gas producer, and pipelines for both products connect the region to big markets such as

Buenos Aires. Alberta also has infrastructure and the means to add more if economics are persuasive. Its light shale oil production could be an effective diluent for growing tar sands production. Thus, Alberta's unconventional oil could end up linked to the province's ability to find logistical outlets for more tar sands heavy oil. Mexico lacks oil and gas infrastructure specific to its border region with the U.S., but could easily build gathering and connection lines to major gas trunk lines carrying imports from the U.S. The problem for both Alberta and Mexican gas logistics is that low U.S. gas prices mean incentives are lacking. The economics for exporting Alberta gas to the U.S. don't exist with U.S. prices at \$2-3 MBTU, and in Mexico's case don't exist for backing out gas imports rooted in those same prices.

China has and will continue to build logistics for its Sichuan gas production. With massive LNG imports at the margin, it has strong incentives to do so, and has recently provided a rough LNG-based price incentive for domestic gas production. China's limiting factors lie more in the prospectivity of its rocks and in other 'above ground' issues rather than in its ability to overcome logistical barriers.

Elsewhere, there is little in the way of onshore gas logistics in either Poland or the U.K. This is no surprise given that production in both locations is essentially zero. Both countries could build infrastructure it if production promised to reach a critical mass. The U.K., given its established North Sea oil/gas industry, could likely do so very efficiently.

We conclude the following from this survey of the Global Supply Curve:

1. No non-U.S. locations unconventional oil is "in the money" at \$50/b or less. Argentina's current oil production benefits from subsidized prices of ~\$65/b.
2. Factoring in drilling costs and logistics, the unconventional oil supply curve looks like this: Canada, Argentina (close to commercial @ \$50/b); Mexico and Russia potentially commercial but currently prioritizing larger volume offshore prospects; all other locations out of the money, except Saudi Arabia, which may incorporate unconventional development into its new production plans.
3. Argentina's natural gas production may be approaching or even "in the money" when compared with imported LNG prices. Canada and Mexico gas production could be "in the money" at similar prices, but must instead contend with U.S. gas prices ~2/3 lower. Some portion of Chinese production in Sichuan may also be "in the money" versus imported LNG.
4. The U.K. and Poland could be "in the money" versus LNG, but are hampered by several factors:
    1. In a low price environment, they are constrained by the fact that few investors are will to take risk in a higher cost environment
    2. Consequently, there is an absence of both exploration data and field 'learning experience' which means these countries start even higher on the industry cost curve.
    3. Both lack onshore logistics, which means that investors will have to see economics sufficiently compelling to develop both the field and supporting logistics.
5. Development in all of the locations is hampered by other 'Above Ground' factors which compound the obstacles noted above.
6. These obstacles on top of the marginal economic fundamentals just discussed, make it clear that major changes are needed if global frac'ing is to progress. There is a need to take stock of all the 'Above Ground' barriers in order to devise 'what needs to change.' The nature and geographic distribution of these Above Ground obstacles will be discussed next.

Above Ground Obstacles beyond Geology and Logistics

Questions: Other than geologic and logistics factors, what other 'Above Ground' obstacles are impeding global unconventional development? How much do these obstacles add to production costs at different locations? Could they be overcome by adoption of different government policies and practices?

A variety of 'Above Ground' obstacles not only impede global unconventional development, but are raising the cost and risk of that development well above conditions in the U.S. However, many of these obstacles are susceptible to corrective political action or policy change.

These obstacles include:

- Uncompetitive oil field service industry structures
- A lack of seismic/ exploratory drilling information, or data that exist are not shared/ accessible
- Price controls on oil & gas
- Activist and community opposition that impedes leasing and land access
- Political risks, ranging from unfavorable exchange rates to forced joint venturing, intellectual property/know-how theft, contract abrogation, and expropriation
- Fiscal regimes not geared to unconventional developments unique characteristics

Uncompetitive oil field services were commented on in the previous section. One additional point is that considerable materials and equipment essential to frac'ing is currently being imported. This is especially the case in locations like Argentina, where materials as prosaic as proppant sand is coming in from the U.S. Such practices both elevate costs and expose operations to foreign exchange risk. Clearly countries need to encourage the growth of local companies capable of servicing unconventional development and supplementing the U.S. 'Big Three.' This can best be done by assuring good price and fiscal incentives and a stable environment, such that private investor activity intensifies. Once drilling activity proliferates, firms other than the Big Three should seek out these growth opportunities; local and regional service providers will also see a chance to back out imported items.

The absence of seismic and drilling data surfaced as a surprise barrier at the conference. Partially this reflects the U.S. experience, where so much was learned by drilling and then evaluating the results. A more cautious environment prevails overseas. To some extent, this results from non-U.S. locations having no counterpart to the plethora of independent U.S. E&P companies. In the U.K. and Poland, small local players have tried to drill a few wells. Their resources have been limited, and they faced land access issues and/or community opposition. Consequently, Polish and U.K. firms have not been able to follow the 'drill and learn' approach of U.S. firms. What little data have been collected may be tightly held, preventing others from building upon that base. A similar 'low activity, little information' story prevails in Mexico, where Pemex has been capital constrained, and the relaxation of its monopoly is too recent to allow entry by U.S. E&P firms. In other countries, abundant data exist from past exploration and production but are kept locked up as state secrets, or to protect their own national oil companies, or for other historical reasons. Collectively, these data restriction practices greatly inhibit the speed at which non-U.S. shale exploration may proceed.

As a result: 1) global frac'ing has largely been left to the oil majors, who have been 'high grading' prospects in the face of low prices; 2) locations like the U.K. and Poland are graded as high risk, partially due to the limited drilling information available; the majors then classify them as unattractive; and 3) drilling activity trends towards zero, compounding the informational disadvantage of these locations.

Almost all non-U.S. locations exhibit 'Above Ground' obstacles unique to each place. Drilling in the U.K. faces determined local and activist opposition; some of it is climate based, some of it simply opposed to disturbance in the more densely populated counties of northern England. Collectively, this opposition has prevented any hydraulic fracturing operations from proceeding. Drillers in Poland face delays in obtaining land access rights, partly due to the governments comfort with burning locally produced brown coal, and partly because of an unresponsive bureaucratic process. China confronts drillers with controlled prices, populated areas so dense that a non-intrusive drilling site is difficult to identify, and with required joint ventures with Chinese SOEs. These SOEs often seek technical learning from the foreign partner as much as the venture's commercial success. Foreign firms daring to venture into north Mexico's Burgos basin must deal with violence and intimidation by drug gangs.

Argentina presents a unique suite of 'Above Ground' risks. Almost all are political in nature. The country's development model has featured heavy state intervention in petroleum markets. For decades, state-owned YPF had a monopoly on domestic production. YPF was then privatized, only to be re-nationalized during the recent Kirchner era. Oil and gas prices have fluctuated between control regimes and reflecting global prices. Gas export contracts have been approved, only to be abrogated later. Foreign exchange has sometimes been freely available, and sometimes rationed; exchange rates have varied from floating to fixed but hugely overvalued. Having extolled Argentina's 'prospectivity,' the counterpoint must be that no 'shale-play' country (outside of possibly Russia) offers foreign investors such a history of rampant political risk. For any foreign investor the relevant question seems to be – can any favorable Argentine environment or policy be sustained long enough to make investing pay off?

A last 'Above Ground' obstacle is common to all locations. None has a fiscal regime custom built to incentivize unconventional development. All have legacy tax regimes designed for conventional or offshore drilling. These legacy regimes were built to tax projects with substantially higher volumes of production. They also were designed in a 'supply-constrained' world to assure that the lion's share of cash flow went to the government as royalties and taxes. These regimes are thoroughly ill-suited to encourage unconventional development. They don't recognize that for such development to be commercial, drilling must sustain an aggregate level of field production that justifies building logistical infrastructure. Nobody is going to build a pipeline for a few wells' initial surge production, only to see the pipeline almost empty as the wells decline to 'long tail' production levels. They also don't recognize that in the less supply constrained world of the future, fiscal regimes will have to focus more on incentivizing investment versus maximizing government's take. The key principles which should shape a model fiscal regime for frac'ing will be discussed in more detail below.

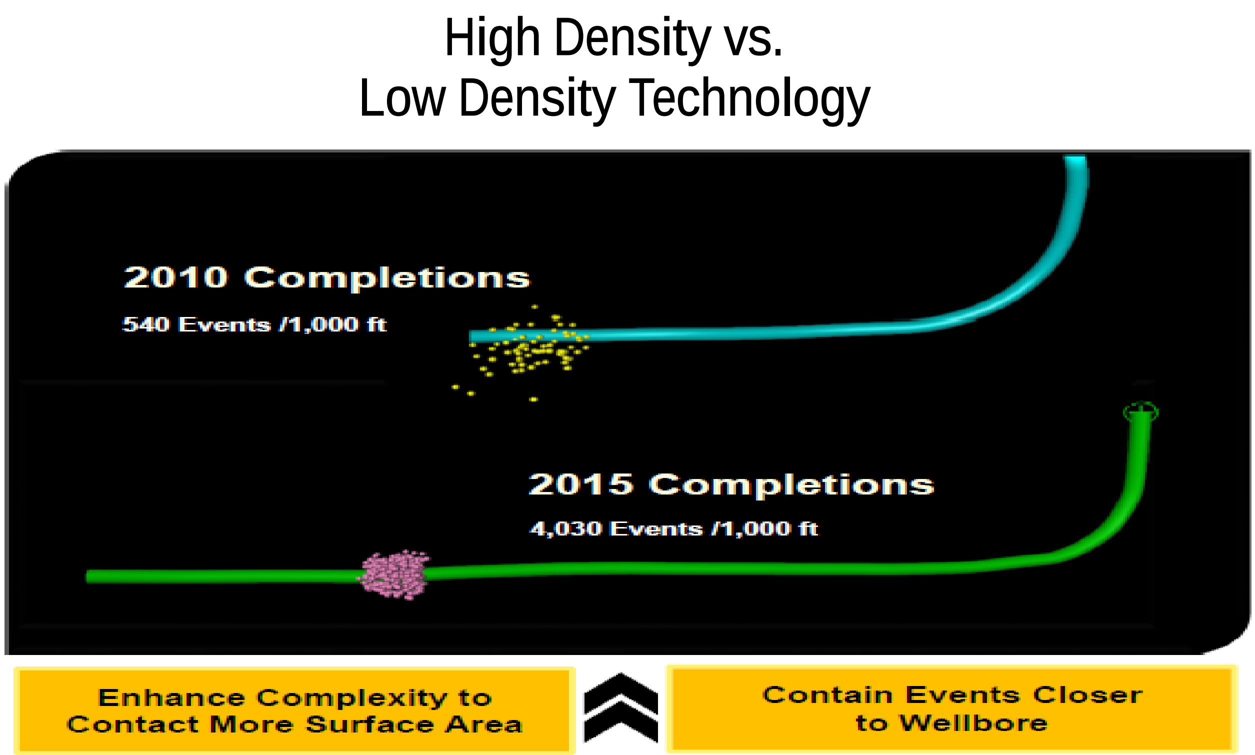
Given that only a few non-U.S. locations are close to 'in the money' on geology and logistics, and these only for natural gas, it should be obvious that these 'Above Ground' obstacles raise production costs well above current price levels. Most however, are self-inflicted wounds. Reasonable policy revisions and better administration can cure many of these ills. Later on this report will offer specific ideas from the conference on how best to remedy several 'Above Ground' issues; these recommendations will address the absence of drilling information, community and activist opposition, and a model frac'ing fiscal regime. It will also talk specifically about what Argentina can do to sustain sound policy reforms.

Now, we turn to discuss whether recent U.S. efficiency gains can be migrated to non-U.S. locations.

U.S. Frac'ing Cost/Production Gains – Can They be Exported?

Questions: What are the principal U.S. improvements that lowered hydraulic fracturing costs while boosting output per well? How much have they lowered unit production costs? Are these gains largely cyclical or more fundamental? Are they a function of U.S.-centric conditions? To what extent can they be migrated to non-U.S. locations and act to bring foreign frac'ing costs closer to being "in the money?"

Operational data from U.S. shale plays suggest very significant efficiency and production gains have been achieved since 2010. Knowledgeable observers cite an 'Edisonian' learning curve, i.e. progress born from repeated experimentation, observation and adjustment. Exhibit 6 provides a dramatic example of frac'ing's progress versus its early days.



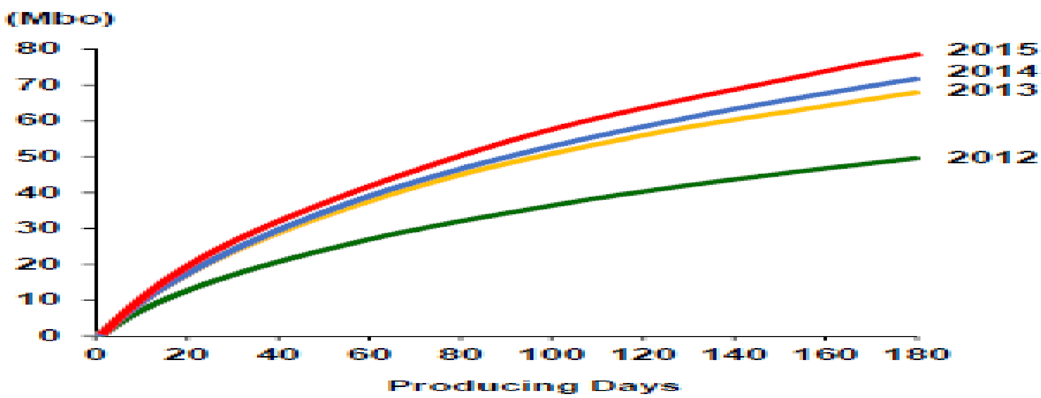
This progress registers as dramatic declines in days spent drilling, capital costs per well, and cumulative production per well. Net economics remain somewhat murky due to offsets, i.e. higher operating costs incurred by using techniques aimed at greater volume production per well.

Various metrics testify to these improvements. For example, in 2012 an average Eagle Ford well took 12.2 days to drill. Today that same well gets drilled in 7.7 days, a 37% improvement. These wells cost just less than $8 M to drill in 2012 and are closer to $6 M in cost today. Similarly, in 2012 an average Eagle Ford well produced about 45 kb over 180 day period, or 250 b/d. Today, a comparable well yields

80 kb or 444 b/d, a gain of 78%. Similar results were obtained in the Bakken and even better results in the Permian basin. Exhibits 7-8, sourced from EOG, provide details on the Eagle Ford improvements:

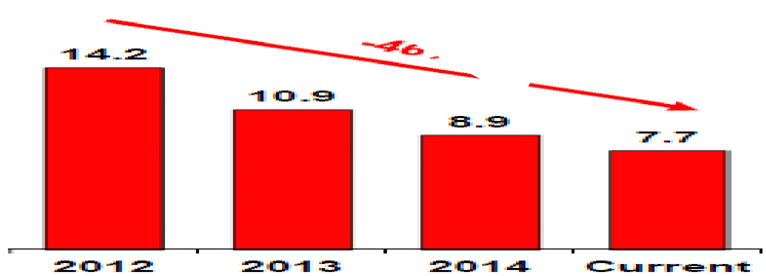
<u>Exhibit 7</u>

Eagle Ford West Shale Wells
<u>Average Cumulative Crude Oil Production*</u>
(Thousand Barrels)



<u>Exhibit 8</u>

Eagle Ford Shale Wells
<u>Average Drilling Days*</u>
(Spud-to-TD)

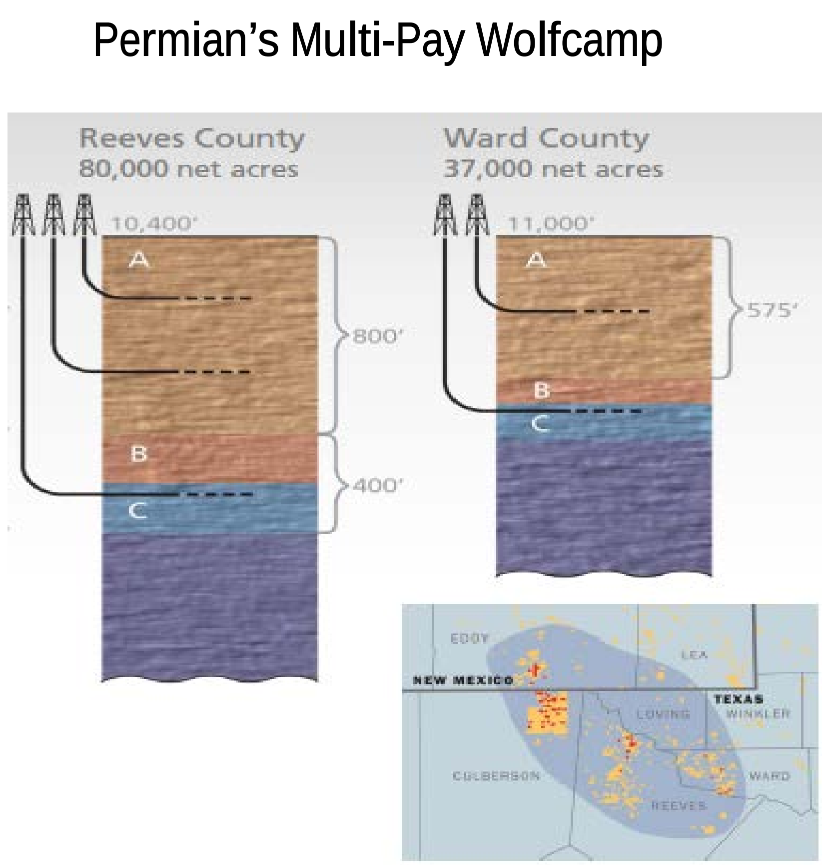


A number of factors account for this progress. The most obvious is a cyclical factor, a huge decline in drilling rig day rates and associated labor and material costs. The price bust has generated surpluses throughout the industry. This means rigs and workers are available at industry trough prices.

The price bust also forced operators with work commitments, contracted rigs and heavy debt loads to do everything possible to stay afloat financially. This meant seeking every possible improvement in drilling operations, well targeting and completion techniques. Here is where the more durable and exportable productivity gains have materialized. Conference speakers emphasized three such gains: longer horizontal wells, increased stages and fracs per well, and stacked multi-lateral completions.

Longer horizontals allow each well to reach aggregate pay zones which earlier would have required moving the rig and drilling additional wells. Increased stages and fracs per well will drain the rock volume around the wellbore more quickly. One data point provided at the conference depicted this to be a 15 x producing area expansion versus a vertical well with a single frac (see Appendix 2). Stacked completions can occur when the operator detects multiple pay zones at different depths, lying vertically in column. When this occurs, the operator can drill a single vertical well bore, send it off horizontally into the first zone, undertake completions there, and then redirect the vertical bore to the next zone where the process is repeated. Conference speakers cited examples were up to five pay zones were reached by a single well. Needless to say, volume per well soars with this technique, while aggregate capital costs decline versus drilling multiple verticals to reach different zones. Exhibit 9 provides a visual look at stacked horizontal completions, albeit with multiple wells rather than a single, multi-lateral well.

Exhibit 9



One factor behind this progress is greater selectivity in well siting. Some of this selectivity represents simple 'hi-grading' i.e. cash strapped operators allocating their limited resources to their best prospects. However, part of it reflects a greater use of seismic data, core analyses and well feedback information to plan drilling programs more strategically. The net result has be stunning – there are far fewer wells in operation, but these have drilled longer horizontals with more completion stages and more fracs, all of these targeted more precisely to the best pay zones – thus yielding far more production than was expected given the decline in operating rig count.

Reliable data about the net effects of this progress is difficult to come by. Production cost estimates occasionally make their way into print, but sometimes reflect cash costs only rather than full costs including a return on capital. The data are also affected by whether they are based on average wells or the best wells drilled into the best zones. Such data as exists suggests that cash costs have dropped to the $20-30/b range s and $40-50/b for full costs plus return for the best play. Average wells drilled into medium prospective locations are clearly above these levels.

Something more reliable may be inferred from the industry's behavior regarding the lay down of drilling rigs. The shale boom accelerated in 2010-12 when dry gas prices were $3.50-$4.50 MBTU and crude ranged from $80-100/b. Such prices led companies big and small to calculate they could make returns drilling for dry gas – remember, hydraulic fracturing originally advanced working on shale gas. Industry 'success' sent gas prices falling below $3 MBTU in 2013. Rigs were either laid down or transferred towards wet gas plays (gas with a relatively high proportion of natural gas liquids). Crude prices were still above $80/b, causing NGLs and condensates to drive shale gas economics. These efforts honed industry shale oil techniques, leading to the dramatic production growth from Eagle Ford, the Bakken and the Permian basins. Dry gas drilling virtually stopped as can be seen from rig counts in former hotbeds like the Haynesville. Crude prices began their slide in June 2014, but still held $60/b as late as April 2015. A second collapse below $30/b followed, reaching bottom in January 2016. Throughout this 18 month decline, rig counts fell steadily in all the oil plays. By first quarter 2016, virtually the only rigs still working were in the wet gas Marcellus and the Permian oil plays. A few rigs still operated in the Bakken and Eagle Ford. Numerous wells in all these locations were left drilled but uncompleted (DUCs).

Oil prices then recovered, reaching the mid-$40s/b in 2Q'16. Gas prices hardly moved. Oil play rig counts stopped declining, and a few rigs went back to work. Some DUCs were completed. ExxonMobil, discussing 1Q'16 results, commented that its rigs in the Bakken and Permian were 'making money.' We infer from this behavior that $40+/b is now more than sufficient to cover 'best play' well cash costs, and that something like $55-60/b, if judged sustainable, would tempt producers to contract new rigs for existing leases. Full cost, start-from-scratch economics probably require $70/b sustainable price levels. The similar numbers for dry gas are probably $3-4 MBTU. These numbers suggest a rough 30% reduction in full cost economics (40-50% for cash costs). A portion of this is cyclical in nature as rig rates, labor costs etc. will recover as activity picks up. However, current surpluses are such that the rate of cost inflation may be quite slow until higher price levels are judged to be firmly in place.

We come now to the question of whether these industry improvements are U.S.-centric, i.e. not repeatable outside the U.S.? The answer is that non-U.S. oil service industry structures will impede but not prevent U.S. advances from spreading. The drilling, completion and targeting know-how exists. The 'big three' service firms that operate internationally know these things; so do the international majors like ExxonMobil, Shell and Chevron and big independents like Apache and Anadarko.

This means that U.S. advances, e.g. stacked, multi-stage drilling and frac'ing, can migrate rapidly abroad through the entry of these U.S. firms. Facing the more costly operating conditions abroad, they will need to deploy the best targeting, drilling and completion techniques to make the economics work.

It is the cyclical portion of U.S. efficiency gains that will prove less exportable. Land rigs and workers are not laying around in Argentina, Mexico or China. The big three firms will also be able to charge for their expertise in less competitive foreign markets. They would rather await recovering oil and gas prices than 'give away' their hard earned know-how at industry trough prices.

We conclude from this that well less than 50% of U.S. productivity gains are immediately replicable in foreign locations. In fact, exportable efficiency gains may be more on the order of 10-20%, depending upon how pricing negotiations fare among technically savvy major oil firms and the 'big three' service companies. U.S. productivity advances will not rescue global frac'ing from its 'Above Ground' barriers and low commodity prices.

That said, as international crude prices rise to $50-60/b, oil-linked LNG prices will also climb. Within a year, markets may again see $8-10 MBTU landed LNG prices. At such levels, international shale gas plays will start looking economic at the more prospective locations. A fuller slate of international firms may get active, and if host governments undertake measures to render their service industries more competitive, a second increment of U.S. productivity gains can migrate overseas.

Local governments may be tempted to think that local content requirements and mandatory joint ventures with domestic companies are the ways to capture these gains. Such measures will likely prove disappointing. These policies really aim to extract know-how from foreign firms and pass it to domestic champions. Whatever one may think of that policy aim, it is not the same thing as promoting efficiency or productivity. Indeed, it usually produces risk adverse behavior and the withholding of technology by foreign partners. Simply encouraging more existing service companies to consider operating abroad will probably produce better migration of U.S. gains.

So far, unconventional development costs have been discussed without reference to environmental factors. This, of course, means the discussion is incomplete. The environmental impact of hydraulic fracturing is potentially significant, and good management of these risks requires know-how and money. U.S. experience is again illuminating here. Taking environmental management properly into account, how does these global frac'ing picture change, and to what extent can U.S. experience provide lessons in sound, cost-effective management? To these issues we now turn.

Global Frac'ing and the Environment – Risks, Management Practices, Costs

Questions: What does U.S. experience tell us about the environmental risks of hydraulic fracturing? Are they sufficiently serious that moratoriums are justified? If not, what risks are most serious and what does U.S. experience suggest about their proper management? How much would sound environmental practices add to development costs in foreign locations?

U.S. frac'ing experience holds many valuable environmental lessons for the rest of the world. Foremost among these is that there are potentially serious environmental impacts associated with frac'ing. Fortunately, all can be mitigated via reasonable operating practices and sound regulation.

U.S. experience also shows that there is a considerable 'learning curve' on frac'ing's environmental issues. Initial concerns involved potential contamination of drinking water by fluids migrating up from the frac'ed zone. These were superseded by the more real issue of induced seismicity, primarily at saltwater disposal sites. Later concerns emerged regarding fugitive methane emissions. This trajectory suggests that there is a rich lode of U.S. environmental experience which non-U.S. countries can and should study closely as they consider authorizing frac'ing. Indeed, conference participants strongly agreed that non-U.S. nations can forestall most environmental issues by harvesting the U.S. lessons and issuing a comprehensive frac'ing regulatory regime prior to allowing significant industry activity.

Since well-crafted and enforced regulations can address frac'ing's issues, moratoriums cannot be justified solely on environmental grounds. However, environmental concerns atop the noise, inconvenience, visual impact and infrastructure damage associated with frac'ing can be expected to induce considerable community opposition. This is especially the case where the community sees few immediate benefits to offset negative impacts and risks. This imbalance of upfront positive and negative impacts makes it easier for activists that oppose frac'ing on other grounds (e.g. keep hydrocarbons in the ground) to spread misinformation and exaggerate frac'ing's risks. Exhibit 10 provides some reminders of frac'ing's visual community impacts.

Exhibit 10

Turning to specific environmental impacts, there is now a consensus that on water contamination 'what goes below, stays below.' This line is shorthand for the fact that water injected into rock thousands of feet below the water table does not find its way back up to drinking water. Research done in Pennsylvania's Marcellus gas field found that from 2008-2013 between 7-64 unconventional wells contaminated 85 drinking water wells. This result implied contamination at less than 1% of the over 6000 wells drilled during the period under study. Moreover, the contaminating activity preceded the current regulations, and the source of the contamination was not the injected frac'ing fluids.

Frac'ing's primary risk of water contamination lies in other areas: improperly lined and cased well bores, and especially the improper disposal of waste water that returns to the surface. The same Marcellus research used isotopic studies to examine the contamination, and determined the likely source was surface spills, not migration of contaminants from depth.

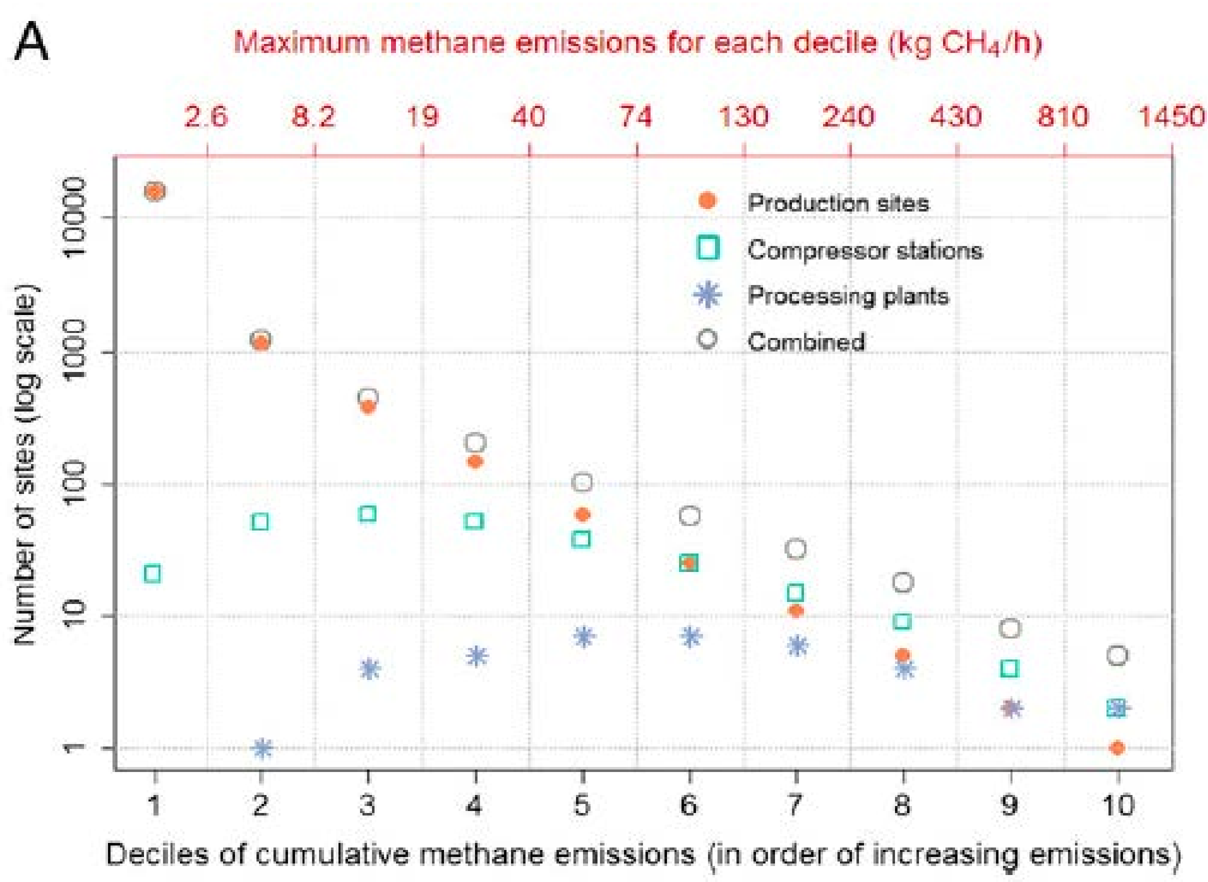
Treating or properly disposing of frac'ing waste water costs money. Waste water volumes are large and can contain not only brine but also subsurface contaminants and even radioactive material. In most places disposal wells drilled below the water table are the most cost effective method. These wells must be properly sited and drilled. There is always the temptation for marginally economic operators to cut corners, so regulatory enforcement is as important as well-crafted rules. This will be a special challenge in non-U.S. locations where frac'ing's economics are marginal and where regulatory practices are less robust than in the U.S.

Induced seismicity exists. Handled badly, it can deeply disturb local communities and damage property. Data suggest that most, but not all of induced seismicity is the result of waste water wells drilled into areas where faults can be reactivated by the water. Reasonable studies of subsurface geology can identify areas prone to such reactivation, and such studies should probably be required prior to authorizing frac'ing or waste water disposal well drilling.

As other issues have receded, fugitive natural gas emissions have emerged as the major environmental issue associated with frac'ing. This can be seen in the latest round of EPA regulations. Methane is a much more powerful greenhouse gas than CO2. Environmentalists and regulators have raised concerns that large scale frac'ing will lead to large scale methane leaks from field and pipeline infrastructure. A parallel concern is the flaring of natural gas associated with shale oil production. Flaring avoids methane releases. However, it does release CO2 into the atmosphere along with wasting a valuable resource.

There is not a lot of data available on fugitive methane by site. Data available in the Marcellus suggests that a small number of sites are responsible for a disproportionate share of measured emissions (the 80/20 rule appears to apply). This suggests that curtailing the worst operators can deliver a disproportionate benefit and should be a high priority. Exhibit 11 provides details on this observation.

Exhibit 11



Zavala-Araiza et al, 2015, Proc. Nat. Acad. Sci., 112, 15597-15602.

Other data show that the majority of fugitive methane occurs via leaks from processing and distribution infrastructure. Some of this can be addressed by tightening up operations. Some of it was designed into the infrastructure years ago. Many pipelines were designed to 'bleed methane,' when valves used line pressure as the actuating mechanism. In production operations, natural gas releases are a result of a practice known as liquids unloading. Non-U.S. locations can benefit from this knowledge, and require infrastructure designs which use alternative technologies (e.g. compressed air for valve operation and the use of plunger lift for the liquids unloading operation) to accomplish the same operating goals without methane leakage.

One implication of the U.S. environmental learning curve is that a sound upfront regulatory regime will involve added costs, and these costs will almost certainly be higher than that those incurred by the U.S. frac'ing industry at the inception of the shale revolution. Back in 2009-10 demand for waste water disposal capacity was growing and new wells were drilled or converted from former producers without much thought of induced seismicity. Gas flaring was a largely uncontested practice. If non-U.S. governments follow the conference recommendation to adopt a frac'ing regulatory regime upfront, it almost certainly will require additional capital and operating expense to address these issues.

The extent of these costs is hard to measure, not least because it will vary by location. To judge from U.S. industry behavior, operators here have not made the cost of complying with tightening regulations a priority concern. Rather, they have been focused on maintaining their 'license to operate' in the face of growing opposition. This suggests that the increase in compliance costs has been 'within the economics noise,' i.e. a small fraction of the price volatility suffered recently. While every dollar counts in a down market, the industry is behaving like the increased environmental costs can be more than absorbed within the permanent cost reductions achieved over the last two years. That would put a rough estimate of these costs in the $5-10/b range for shale oil and $0.30-0.50/MBTU for gas.

Obviously, the costs of sound environmental practice will be lower in non-U.S. places where disposal wells are easily drilled, where natural gas enjoys delivery infrastructure to market, and where seismicity isn't an issue. Argentina's Vaca Muerta, to name one location, exhibits many of these characteristics. China, Poland and the U.K. each lacks some of these advantages and likely involves higher compliance costs. Mexico, with its proximity to U.S. service providers, trunk line natural gas infrastructure, and need to favor water recycling, is probably closer to Argentina.

When designing an upfront regulatory regime, non-U.S. locations should look carefully at that now evolving in Alberta. The Alberta Energy Regulator (AER) possesses a dual mandate: "to assure the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources over their entire life cycle…while providing economic benefits for all Albertans." This dual mandate instills in the regulator complementary concerns for effective development and environmental safety. These can be seen in the AER's comprehensive regime, which addresses hot button issues like well integrity, seismicity and air emissions; at the same time the AER has simplified operator approval processes, so that operating licenses for drilling, air, water and pipeline operations can be combined in a single application and acted on by the regulator.

The AER also has a pilot study that bears watching. This study envisions "Area Regulatory regimes." Under this approach the AER works with the energy firm to define a development area to be regulated. The developer provides information regarding the geologic and operating characteristics that define this area. It and the AER then develop regulations specific to the defined area that take account of the unique risk profile posed by that area, which may be either more or less than some norm, depending upon the risk in question. This approach holds the potential to concentrate operator and AER attention on more serious risks while lightening the regulatory burden in areas where potential hazards are not material. Should this approach prove workable, it could deliver both more environmentally safe and more efficient regulatory regimes. Non-U.S. locations could use a similar approach to achieve responsible development without unduly burdening operators on costs.

A full statement of the AER's mandate, examples of its regulatory regime and highlights from its Area pilot study are provided in Appendix 2

There exists no central clearinghouse for information on frac'ing operations and environmental experience. There is also very little in the way of baseline testing that precedes frac'ing operations. There is a particular need for regulators to pre-determine the correct analytes, spatial distributions and other components for operators to compile the baseline data needed for an area regulatory regime.

These information gaps pose risks for non-U.S. development. The absence of a central clearinghouse makes it difficult for regulators to see the lessons learned in the U.S. and Canada. The lack of baseline data makes it easy to confuse contaminations found after frac'ing begins with pollution caused by frac'ing. In Pennsylvania, for example, methane was found to pre-date shale drilling in 24% of area water wells, a fact only determined after *Gaslands* has caused controversy by filming the lighting of a area water faucet. Industry operators should encourage government energy agencies to form such a clearinghouse and should be willing to contribute resources and funding to bring it about.

Sound regulation of unconventional development has proven feasible. It can be accomplished at non-U.S. locations at some cost, but with more efficiency by profiting from North America's experience. Incremental costs are probably bearable in a world of $70-90/b crude and $8-10 MBTU LNG. There is however, another 'Above Ground' risk that needs attention – fiscal regimes which accommodate frac'ing's unique operating and economic characteristics.

Fiscal Regimes: Unsuitable Legacies and the Need for Customized Designs

Questions: What various types of fiscal regimes currently govern U.S. and non-U.S. unconventional development? Do any of these regimes expressly consider fracking's unique characteristics? What are fracking's unique characteristics as compared with conventional or offshore developments? How do these characteristics fare under existing fiscal regimes? What principles should govern a fiscal regime designed to incentivize unconventional development?

Global fiscal regimes for oil & gas come in two basic varieties, Tax/Royalty regimes and Production Sharing Contracts. As currently written most fiscal regimes are ill-suited for frac'ing operations.

In a Tax/Royalty regime, the owner of the mineral rights is compensated with a 'separation payment' - in the form of a percentage of pre-tax revenue generated from the production (the royalty). This royalty can go to the government or a private party depending on the location involved. Also, the royalties can be calculated as a percentage of the revenue/production – or as a percentage of the profit (revenues less deductible expenses needed to monetize the resource). The government is then entitled to an income tax applied to taxable income, i.e. revenues net of royalty payments less all deductible expenses, including operating costs, depreciation and amortization. The U.S. and many other nations have Tax/Royalty regimes; in the U.S. royalties range from 5-25% with a 35% statutory tax rate.

Tax/Royalty regimes can support frac'ing operations, depending on the level of tax rates and especially royalties that are set. As will be discussed below, high royalties act as a strong disincentive for unconventional development. U.S. royalties often have been quite high. This disincentive was overcome due to other U.S. advantages, e.g. established logistics, competitive oil field services and the absence of progressive income tax rates. However, when the price downturn hit, high royalty rates contributed to driller decisions to suspend drilling and/or leave wells uncompleted.

Production Sharing Contracts (PSCs) use a framework which involves the sharing of the oil (or gas) produced over the life of the contract. Under a PSC, the government maintains ownership of all the resources in the ground, and the investor is awarded production volumes to recover costs incurred during the exploration, development, and production operations ("Cost Oil"). The volumes left after the investor has received cost oil are considered "Profit Oil". This is shared between the government and the investor according to the term of the contract. PSCs were developed in the wake of OPEC's nationalizations of private company concessions. They represented a bargain struck by governments who needed private companies to undertake development, but didn't want to stand accused of allowing a foreign entity to 'exploit' the national patrimony. Private firms agreed to PSCs because they wanted access to attractive resource plays, and because PSCs promised them both a quick recovery of development costs and satisfactory returns on capital.

The problem with many PSCs as a fiscal regime for shale plays is the government's desire to capture most of the "upside" from their resources without sharing in the downside price risk. This approach is rooted in the concept that the resource belongs to the country, and that the investors should receive the minimum level of compensation needed to incentivize the investment. Whatever the validity of this framework for conventional and offshore projects, it is ill suited to unconventional development. Shale plays require fiscal incentives to support continuous drilling and to be 'dynamic on price' in both directions if a field is to be optimally developed. This is explained more fully just below.

Many PSC are highly progressive tax systems designed to give most of value to the government once certain production or economic milestones have been achieved. Common milestones used to trigger higher shares of the profit oil to the government are Investor's rate of return, R-Factors (cumulative ratio of revenues to costs), and cumulative production. Many of these progressive PSCs trigger marginal effective tax rates as high as 90%, and these are irreversible – even when prices drop significantly. Governments like this because if shields them from criticism for "giving away" their resources to foreign investors. However, this asymmetric sharing of risk and reward is not well suited for supporting high cost production that is easily suspended – which is where shale fits on the supply cost seriatim.

Another issue for the PSCs as they are now structured is how they separate the exploration, development and production activities into sequential time periods with predefined durations and associated constraints as to what activities are allowed to occur within each of these periods. A common example would be to a have a four year period to conduct exploration followed by a six year period to develop the resource, and finally, a 20-25 year period to produce the resource. The nature of unconventional resources is one of continuous and complete overlap of all of these activities going on concurrently. "Exploration" and development activities will be ongoing throughout the project life – long after production activities have begun.

Imbedded within this structure of a discrete exploration period, most PSCs require that areas outside the discovered "field boundaries" be relinquished back to the government – also known as "shrink wrapping". For unconventional resources, there are no "field boundaries." The targeted resource is the source rock and can cover the entire area under contract. So this "shrink wrap' feature is not compatible with the exploitation of unconventional resources.

Turning now to what would incentivize development of unconventional resources, there is a need to inventory their unique characteristics and contrast them with other types of hydrocarbon development. Only when these differences are clear can the optimal form of frac'ing fiscal regime come into focus. To illustrate these differences, we now compare a typical frac'ing operation with offshore production.

The best metric for gauging these differences is per well production. An average well drilled into the Eagle Ford formation may produce 200-400 barrels of oil per day. For an offshore platform to be commercial, developers seek reserves capable of producing ten times that much per well. Moreover, the production profile of these wells differs in another respect. Shale wells deliver an initial surge production that peaks within six months and then steeply declines. After a decline phase lasting six to twelve months, production flattens into a long, gently declining tail that lasts multiple years. Offshore wells sustain their high production in plateau like fashion for several years. It is this production plateau which enables developers to harvest their cost oil and begin earning their return on investment.

These different volumes and production profiles hold major implications for development economics. For offshore prospects, it means that exploration results are the critical success factor. Sufficient reserves must be found such that developers foresee both high volumes per well and a high sustainable production plateau. This allows the developer to model **both production and logistical facilities** with reasonable assurance that they will be fully and efficiently utilized. Necessary capital is costed upfront and the developer can project the likelihood of an acceptable return assuming PSC terms and a given range of prices. All this is done *ex ante*, i.e. before capital is spent. When the platform comes on, the developer knows efficient logistics will be there and be fully utilized. It all gets built as a unit.

Things are different for shale plays. Because per well production is so much smaller and the falloff so much quicker, shale players know they are going to have to drill many wells before they can reach and sustain production sufficient to fill up a pipeline. This is why so much early shale production ends up being delivered by less efficient means, e.g. truck or rail. To put it in different terms, shale players know they will need to hit a level of **'field drilling intensity'** that justifies constructing efficient logistics. This requires a large number of producing wells and continuous drilling. Developers must drill their way to a critical mass of production and accept logistical debits in the process. If they fail to convince midstream providers that a suitable production plateau can be sustained, efficient logistics for that field will never be built. In this sense, shale players face a scale-up problem - can they organize and fund this critical mass drilling program to bring about needed logistics, knowing that they will see suboptimal economics on all production while they 'ramp up?'

A fiscal regime crafted to promote unconventional development would focus on incentivizing producers to reach 'field drilling intensity.' Only reaching that level of activity will assure parallel development of infrastructure, such that full exploitation of the reserves can proceed on the most efficient basis. Without efficient logistics, shale developers are greatly exposed to market volatility and may be forced to abandon drilling before the field's potential is actually realized.

This vulnerability is acute for another reason. Shale production is likely to be the 'marginal source of production' for years to come. This is so because frac'ing is a short cycle play, i.e. relatively easy to stop and start. Shale plays also involve relatively high operating costs on a unit of production basis. By way of contrast, offshore projects, LNG, tar sands all take years to develop. These projects also require large capital amounts; once that money is spent however, (sunk in industry parlance) offshore plays and LNG boast low unit operating costs. Consequently, they are seldom "shut-in" when prices decline. Shale plays, with their need for continuous drilling and their reliance on labor, water and chemicals, spend much more in operating costs. Consequently, frac'ing operations are likely to be among the first activities to go 'cash negative' when oil and gas prices decline. This all adds up to frac'ing operations being the first to cut back when prices drop and the first to come back when they rise.

Frac'ing's marginality thus requires governments to think differently if they want to optimize their aggregate 'government-take.' The issues for governments become: 1) how to encourage the developer to invest to reach sustainable production that justifies building infrastructure, and 2) how to incentivize continuous drilling that maximizes total recovery from the development area. Said differently, in unconventional development the government's interests lie in maximizing total production over time. A failure to take this approach will more likely either discourage much production from every occurring and/or see production quickly decline when prices dip.

Taking all this into account, a model fracking fiscal regime would be built using the following principles:

- The fiscal regime should be customized for a defined production area. This production area should consider the logistics system needed to efficiently monetize the resource, and a level of production and drilling activity sufficient to justify this system. The 'field drilling intensity level' can then be associated with drilling activity, capital and operating costs, and a time frame over which the developer gets to the 'target sustainable production plateau.'

- Most of the cash flow should go to the developer during this ‘field production ramp-up’ stage. This is to provide the developer with maximum incentive to reach volumes that justify building infrastructure. It also is needed to help finance the ongoing drilling needed to hit the target production plateau. In substance, this would not be much different than PSCs giving developers a higher proportion of the revenues to recover their upfront costs (‘cost oil’). Once the target production plateau is reached, government take can increase.
- The level of government take should keep in mind frac’ing’s exposure as the marginal source of production. A frac’ing fiscal regime should be ‘dynamic,’ meaning that its income tax rates should be sensitive to commodity price levels. Once a field reaches sustained production and the income tax rate moves to its target level, it should be sensitive within a moderate band to price levels in both directions. This flexibility in tax rates can help fracking be resilient in the face of price volatility. The median tax rate should be relatively low, but allowed to rise if high prices produce a windfall and fall when a downturn hits. The near-confiscatory rates found in many PSCs should be avoided, as the ability to participate in price upside has been one of the incentives fueling the U.S. shale boom.
- These principles imply that revenue or production-based royalties are a disincentive to fracking’s progressing, and should be avoided or at least minimized. High levels of these types of royalties result in payments to the government irrespective of whether fracking’s production is actually in the money, and can present a serious deterrent to ramp up investment at times of low prices. The majority of the government take should take the form of Net Profit Royalties or taxes that are applied to the profits (revenues less cost incurred to monetize the resource) rather than revenues or production.
- Local communities should see up-front cash to encourage them to tolerate the noise, disruption and visual impacts of initiating fracking. These can best be delivered via impact fees negotiated with the developer prior to commencing exploration. These fees can be payable upon contract signing. Funds should be directed to specific financial funds with dedicated uses that will encourage community support. These can take the form of agreed local development projects, support for hospitals, schools or worker education, and/or escrow accounts for road maintenance and land restauration.
- The negotiation of area or field fiscal regimes allows the specific prospectivity and logistical circumstances of given fields to be taken into account. These can also be combined with Area Regulatory regimes, so that developers get the critical legal and tax rules surrounding their prospect defined in one customized package. The Alberta Energy Regulator’s experience here will be worth monitoring.

A model fracking fiscal regime based upon these principles is laid out in Appendix 3.

Additional Conference Observations, By Location

In this section we capture other salient observations made at the conference on specific locations. This review proceeds alphabetically, starting with Argentina and ending with the U.K.

Argentina

(the conference was indebted to Accenture Consulting who could not attend, but who contributed formal presentation materials that complemented speaker comments)

- State-owned YPF is playing a major role in Argentine unconventional development, acting as a joint venture partner to international majors like Chevron. This brings into play YPF's political access and acceptability to local communities, but also its fiscal vagaries and objectives which often differ from those of private investors.
- The new Macri government is in the early stages of determining how it will encourage unconventional development. Liberalizing the foreign exchange regime by floating the peso has led to devaluation, which lowers Argentina's labor and material costs in $US terms. Revised fiscal terms have yet to be issued, but import/export taxes and quotas have been removed.
- For now the government has left in place pricing that incentivizes frac'ing, i.e. above world market pricing for oil (~$67/b) and 'new' natural gas (~$7-8/MBTU).
- Argentina has a local oil services industry, but it remains small and immature. Developers not only import frac'ing chemicals but even sand. Local horizontal drilling expertise is lacking.
- High Argentine drilling costs are coming down. In addition to the devaluation benefit cited above, field operations recently moved onto a 24 hour basis, and local proppant supplies are now materializing. While costs are moving in the right direction, high base labor rates and an uncompetitive services market still keep Argentine drilling costs 2 x those in the U.S.
- In sum, most Argentine unconventional development indicators are moving in the right direction. This is encouraging more activity by international companies, but commitments remain cautious as the ability of Argentina to sustain supportive policies through a change in government is still suspect. As an example, Bloomberg reported post-conference that ExxonMobil could put up to $10 billion into the Vaca Muerta. However, ExxonMobil's actual plans call only for a pilot project costing $250 M.

Canada

- Alberta's conventional oil and gas reserves are largely depleted. Reserves constitute less than 10 years of supply at current production rates.
- Alberta's energy future will consist entirely of tar sands development unless it taps its unconventional potential
- These resources are surprisingly huge. In addition to hundreds of billions of tar sands barrels and some tight oil, AER estimates Alberta's unconventional gas to exceed 3 thousand trillion cubic feet. How much of this is economically recoverable remains to be seen, but the sheer size of the resources and Alberta's advanced state of industry development suggests something in the range of 10-20 % should be producible.
- The advanced state of Alberta's industry is suggested by the extensive unconventional drilling already practiced. The AER reported on the area where it is piloting its new regulatory approach. In that area alone, 912 oil wells were drilled of which 572 were horizontal, multi-

stage frac'ing wells. In the same area, 1145 gas wells were drilled of which 662 were horizontal, multi-stage wells.

- Given the U.S. gas glut, the most likely forward path is development of Alberta's light shale oil resources. These can compensate further declines in conventional oil and provide diluent to tar sands projects. As U.S. Bakken infrastructure improves, some shale oil and gas may find its way south to U.S. markets.

China

- China offers an inhospitable environment for foreign shale play investors. Despite having perhaps the biggest incentives of any country to maximize domestic oil and gas, China continues to rely on its national champions for development. These firms have complex agendas and growing their know-how in unconventional development via joint ventures appears a higher priority than commercial success. To date these firms have made marginal contributions of managerial and technical resources to these ventures.
- China's fiscal regime makes no accommodation for frac'ing's needs, and has positively discouraged major companies from operating there. The government has provided attractive pricing for natural gas via a link to imported LNG.
- Foreign firms that do oil and gas ventures in China are expected to pay all the upfront costs and shoulder all the risks, in hopes of an eventual payback in a success case. It can be frustrating that abundant local subsurface and infrastructure data that could help the partnership are withheld, while it is expected that the foreign partner openly share its technology and know-how.
- China is a high cost frac'ing location for many reasons. Its geology is complex and water is scarce in northern shale regions. The local service industry operates effectively as subsidiaries of the major State-Owned Enterprises (SOE). Competition is thus limited.
- China's best shale resources lie in densely populated Sichuan province. Field drilling operations are hampered by their proximity to communities and drilling sites can be hard to identify. Local transportation and logistics are crowded and unreliable.
- While China's unconventional resources are vast, it may have decided that in an era of low prices, it is unlikely to attract much foreign interest for its high cost frac'ing. For now, the costs of importing oil an LNG are bearable. Should oil prices rise towards $100/b, driving up LNG in the process, China may reconsider its approach

Mexico

- Mexican oil production is down 1.2 MB/D from its 2005 peak, even as it has more than doubled annual investment to over $20 billion.
- In principle, Mexico's energy reform promises open access for private firms and foreign companies to all components of the oil and gas value chain. The details of this access remain sketchy, but major firms are now negotiating joint venture arrangements with Pemex.
- While the Burgos basin contains most of Mexico's unconventional gas reserves, Mexico sees the Tampico area as holding perhaps 30 billion barrels of shale oil. How much of this is technically or economically recoverable is TBD.
- Mexico has carried out three licensing rounds under its energy reform. Results to date have been modest, a few exploration and extraction PSCs for offshore and 25 license contracts for onshore. While the latter sounds impressive, there is little data suggesting this will lead to

significant production anytime soon. Mexico is forecasting 280 kb/d of eventual production for all three rounds, which would offset perhaps two years of conventional decline.

- Mexico is more interested in its fourth bidding round, which will be for deep water prospects. Interestingly, these prospects are closer to Campeche than to the U.S.-Mexico maritime border. Nine companies have already signed up for this bidding round.
- Mexico claims to be interested in developing Burgos natural gas for reasons of self-sufficiency and balance of payments. The question is where this goal will shake out among Mexico's priorities. Reasonable laws and fiscal inducements, plus security measures could probably induce some U.S. E&P firms to venture south, especially of Mexico also provided some price incentive for domestically produced gas.

Poland

- Poland places a long list of barriers in front of foreign frac'ing firms while lacking the domestic industry for self-development. Auction procedures are time consuming as are regulatory requirements for accessing the drilling site. Foreign drilling contractors face lengthy EU and Polish approval processes, which act as a protection for Poland's inefficient domestic drillers. Poland's fiscal regime offers no special incentives and if anything is a discouragement. Domestic gas prices are controlled, with their future course uncertain. Data that may exist are difficult to locate and may be deliberately withheld.
- The former Polish government undertook few, if any measures to encourage domestic gas production. Instead, it remained committed to domestic brown coal mining, supplemented by Russian and Norwegian gas plus some LNG. The new government's policies are TBD, but thus far it has shown no signs of deviating from the pre-existing policies.
- The EU generally has favored diversifying natural gas supplies via building more pipelines and bringing in more LNG. So far, this has been judged an adequate response to Russian supply and price manipulations. Industrial demand for natural gas has declined in Europe, easing the pressure on gas supplies.
- Poland is in line with these EU diversification policies. Where it deviates is on climate policy. Poland's commitment to domestic brown coal and to the employment that provides, means it will have difficulty meeting EU GHG emissions targets. Whether this leads future governments to reconsider incentives for frac'ing remains to be seen.

United Kingdom

- Unlike continental EU countries, the U.K. government is "all in for frac'ing." The Cameron government has actively sought to incentivize unconventional development and attract foreign investors to its shale plays. Its planned exit from the EU may only intensify U.K. interest in self-sufficiency energy policies.
- Major unfavorable trends figure into this U.K. stance. North Sea gas production is in rapid decline. Meanwhile, the U.K. has completely phased out coal mining and coal burning for electricity generation. The U.K. is thus increasingly dependent on imported LNG for power. Its considerable petrochemical industry is cost-defensive due to high priced feedstock, especially relative to U.S. producers using natural gas liquids from shale plays.
- U.K. government sees potential for 3 BCF/d of shale gas production by 2030, equal to 50% of domestic demand. A strategy to incentivize shale gas also fits with northern England economic and political strategy of the Conservative government.

- Unconventional drilling requires local council review and approval. This has enabled environmental opposition to achieve a de-facto moratorium by fighting frac'ing at the local level. Only one frac'ing well was drilled in U.K. in last five years. The Cameron government did enact legislation to limit time allowed for local approvals, with unresolved applications defaulting to the central government for decision.
- The U.K. has a sophisticated approach to hydrocarbon fiscal regimes rooted in its North Sea experience. There the government wrestled with the view it had been too generous to developers in the early stages, and a later reality of having to restore incentives as production declined. The Conservative government has signaled plans for a new tax regime which it promises will be "the most generous for shale in the world."
- The current government is also pioneering structures that provide local communities with incentives to allow frac'ing. These efforts include channeling 'Business rates' to local councils, requiring impact fees during exploration and directing other charges to local communities and a 'Sovereign Wealth Fund for the North.' These efforts seek to overcome local resistance, compensate the disruption associated with frac'ing, and assure that funds so allocated result in visible benefits for the affected areas.
- The U.K. suffers from an information deficit due to its lack of actual drilling. As a result, industry is not prioritizing U.K. frac'ing opportunities. While prices are low, major companies 'hi-grade' their prospects, and U.K. frontier frac'ing doesn't come out high on the list. Independent firms more disposed to look at the U.K. lack capital and appetite to overcome local resistance. Both issues may moderate as higher prices whet industry appetites to pursue new opportunities while restoring their finances.

What Has to Change for Global Frac'ing to be a Game Changer? Summing Up

This report amply reveals that above-ground barriers to unconventional development are formidable. Governments can greatly improve the economics of developing their shale resources by attacking the thicket of land access, market structure, hydrocarbon pricing, environmental regulatory and fiscal barriers. Collectively these obstacles more than double the cost of frac'ing in some non-U.S. locations.

There is a proper way, a priority order, for removing these obstacles. You have seen how a paucity of drilling activity in some locations feeds on itself – there is a lack of information relative to other locations, and firms prefer to go to prospects where more data improves their odds of success. ***This means that countries have to prioritize attracting exploratory drilling.*** That requires facilitating explorer access to prospects and drill sites, and providing them with a fiscal regime which provides incentives for fully exploiting the resource.

T***his means a country should first put in place a comprehensive regulatory framework and a frac'ing-specific fiscal regime, one that incentivized 'field intensity' drilling. T***he regulatory framework would address the several environmental issues already encountered in the U.S and largely addressed by the regulations in many individual states. It would be very clear what's required for well completions, especially casing and cementing, and restorations after cessation of active operations and finally after well abandonment. It would require seismic studies before operators began drilling waste water disposal wells. Chemicals use and disclosure would be defined, as would rules for natural gas flaring and avoidance of methane leaks. Resources for enforcement would be adequate and obvious. Putting these rules in place should reassure affected communities while providing the government with a basis for resisting 'no frac' moratorium campaigns.

In short, the depth and extent of U.S. experience on frac'ing and the environment provides non-U.S. governments with all the data necessary to compose sound environmental regulations.

By drawing upon these lessons and pre-positioning regulations, governments should then be able to streamline drilling approvals. Shaky regulators resort to delaying reviews when facing determined opposition they lack conviction to overcome. ***Well-crafted environmental regulations are readily in reach today. They can be combined with streamlined review processes that limit the number of bodies whose consent must be obtained and the time allotted for regulators to reach decisions.***

The fiscal regime should support the regulatory framework by providing for impact fees and/or other front-end money to go into the local community. It is essential that affected communities benefit early and visibly from activities that otherwise promise noise, traffic, worn roads and visible eyesores. Beyond that, ***the frac'ing-specific fiscal regime needs to support the 'ramp up' to target field intensity drilling. That necessitates a light front-end tax burden until the defined field reaches a target sustainable production***. This tax burden should facilitate well cost recovery, and emphasize taxing income rather than revenue. Collectively, such provisions mean that a frac'ing-specific fiscal regime will deviate materially from those applying to conventional or offshore production. Given frac'ing's future as the global marginal source of oil and natural gas, that is as it should be.

Canada and the U.K. can be the 'precedent setters' on both of these fronts. Countries interested in their unconventional resources should monitor these two lands for models they could use. Canada's pioneering of 'area regulatory regimes' may turn out to be the best synthesis of U.S. environmental experience and streamlined procedures for drilling approvals. The U.K.'s work on limiting local council environmental reviews is also noteworthy. So too are the Conservative fiscal initiatives, impact fees and per exploration well cash payments that give local communities a stake in allowing drilling

It remains to be seen whether the Conservative government gets the chance and has the determination to overcome local resistance once drilling has been authorized. If it does, the U.K. precedent may loom large for all of continental Europe.

While ***industry players*** will undoubtedly look at their seriatim of prospects and favor the most attractive among them, they ***should recognize a systemic incentive to support the initiatives under way in Alberta and the U.K.*** Major firms such as ExxonMobil, Shell, Anadarko, Apache, Total and Chevron, and service firms like Schlumberger and Halliburton should engage with regulators in both locations, and give strong consideration to undertaking some exploration work as a means of validating the reforms enacted.

Argentina is the location that can benefit soonest from regulatory and fiscal reform, such as those in process in Canada and the U.K. The import of good regimes combined with its highly prospective geology and installed infrastructure could make Argentina the first non-U.S. frac'ing 'breakthrough location.' Once other countries observe the results obtainable, imitation and improvement of the Canada/U.K. frameworks will follow.

Argentina faces the biggest challenge in terms of convincing investors that its reforms are sustainable. The country ***should consider generously sharing frac'ing's government take with local and provincial communities. This will build support for frac'ing operations and make it harder for subsequent central governments to repudiate the Macri administration's initiatives.*** When all the government take flows to Buenos Aires, the central government finds it easy to simply raise rates to suck in more funds. When the fiscal framework disburses that money among many stakeholders, revamping the regime is neither so easy politically nor so rewarding.

Argentina may provide a model for other locations in two other ways. First ***it is worth noting its practice of pricing 'new gas' at something approaching parity with LNG imports.*** We've commented above that frac'ing for natural gas is likely to see stronger prices, due to many countries reliance on LNG imports for marginal supplies. Letting this price signal work may prove the quickest way to convince investors that non-U.S. frac'ing can be in the money. This approach can be especially useful in Europe, where gas price uncertainties have contributed to a frac'ing paralysis in places like Poland.

Secondly, Argentina may prove the laboratory for non-U.S. locations interested in developing more competitive oil field service industries. Argentine operators are already using some local drilling companies and proppants. The question will be whether the Macri administration strongly encourages smaller U.S. plus European and Brazilian service firms to pursue Vaca Muerta business. The Macri government could accomplish this with an aggressive information campaign promoting its reforms and the prospects of Argentina as frac'ing's next hot spot. Channeling some of YPF's frac'ing business to small U.S. firms renowned for their know-how would reinforce the market opening.

Mexico may be the best positioned country to benefit from other nations' initiatives. By the time it finishes its 4th licensing round (deep water offshore), it may be able to consider not only the reforms enacted in Alberta and the U.K., but also Argentina's progress. By that time, the U.S. frac'ing industry may also have recovered. This would position Mexico to make a decision about promoting gas development in the Burgos basin. ***The country would need to consider a frac'ing-specific fiscal regime, and think about some premium pricing versus pipeline gas imports from the U.S.*** Physical security issues would need to be addressed, and these could possibly be dealt with by channeling upfront impact fees into law enforcement and protection measures.

As noted, ***China and Poland exhibit environments discouraging to unconventional development.*** In China's case, the playing field is littered with obstacles from difficult drilling conditions to an ill-suited fiscal regime. That playing field is also tilted strongly in favor of the giant local SOEs and their service company subsidiaries and partners***. If and when China decides to alter this model, it could signal this by strongly incentivizing non-SOE local company activity, and combine this with a frac'ing-specific fiscal regime modeled on the U.S., Canada or U.K.***

Poland's story is different. With so few wells having been drilled, Poland has had almost no chance to evaluate its resources. This lack of drilling also means Poland has hardly moved down the learning curve in terms of cost reduction or well productivity. Thus, ***Poland's first task is to rekindle exploration interest. It could do this by thoroughly revamping its land access and environmental review processes, and putting in place a frac'ing-specific fiscal regime.*** Subsurface data should be collected centrally and freely shared. Poland is another country that can benefit from the initiatives now underway in Alberta, the U.K. and even Argentina.

In conclusion, Global Frac'ing is going to happen. As this report indicates, some unconventional development is likely economic at $70/b oil and $8-10 MBTU natural gas. These locations will show the way in terms of regulatory and fiscal reforms that can coax forth significant volumes. At these prices, global oil and natural gas demand is also likely to grow. That will create the need for additional supplies. ***Global frac'ing will provide one of the quickest potential responses to these signals from the demand side. By responding quicker, it may preempt other projects that take longer to come to market.***

Which countries are then going to be well positioned to respond rising prices? It will be those who use this downturn period to restructure and customize their above-ground frameworks to encourage unconventional development. Argentina, Alberta, and the U.K. look to be on the cusp of accomplishing exactly that. If they succeed, they will not only reinvigorate their own economies but add their own roadmaps to that already created in the U.S. Stay tuned.

Appendix 1

Conference Program, April 1-2, 2016:
Global Frac'ing, What has to Change for it to Be a Game Changer?

8:30-9:00 Welcome! Conference Host's Opening Remarks, Introduction of guests and 1st Panel – Welcome by Stephen Arbogast, Director, Kenan-Flagler Energy Center

- Intro to the conference- Overview of how the 1 ½ days will work
    - What is meant by Frac'ing – how it works
    - Success in U.S. contrasted with Disappointments Globally
    - What is the Vision? What Benefits Frac'ing Success might Bring

9:00-10:00 1st Round – Baseline: Nature of US Frac'ing Success, Current Conditions
Panel Discussion:

Moderator: Stephen

Why/How Frac'ing works here

- Challenges of $50/b oil, <$3/MBTU natural gas, and recent cost reduction efforts
- Where is today's technical and operating frontier
- What U.S. Frac'ing is really "in the money" today?

10:15-11:00 2nd Round - Is the Potential Really There?
Featured Address:

- Where are the non-U.S. reserves? How prospective volumetrically as reserves?
- Do non-U.S. shale reserves present special technical challenges? If so, what
- Strictly in terms of formation quality, depth, location etc., how do non-U.S. resources compare with U.S. in terms of drilling/extraction costs?

11:00-12:00 – What's Gone Wrong Till Now? Contrasting Europe, L. America, China
Panel Discussion:

Vikram Rao, RTI International, Moderator

- Major international oil firms have abandoned or curtailed frac'ing operations in a host of non-U.S. locations, e.g. Poland, Czech Republic, Ukraine, Romania and China. What reasons have they given for abandoning these efforts?
- Considering the following locations and project development issues, which issues have had the biggest adverse impacts on frac'ing in the different locations?

Location	Issue
o China	1) reserve depth and geologic complexity
o Argentina	2) water availability and waste disposal
o Mexico	3) field and transportation infrastructure
o Eastern Europe	4) knowledgeable service companies and project sponsors
o U.K.	5) provisions for sand, chemicals, crews

- By location, how much do these issues add to U.S.-based production costs?

12:00-1:30 Lunch and Luncheon Address – "What Has to Exist for Global Frac'ing to Progress"

1:45-3:00 3rd Round – Environmental and Community Issues
Panel Discussion:

Vikram Rao, RTI International, Moderator

- After 7 years of extensive US frac'ing of "tight" oil/gas, what environmental issues emerge as legitimate concerns vs. those largely mitigated by industry practice?
- What lessons have emerged from US frac'ing in terms of Industry "best practices" on key environmental risks?
- To what extent are these environmental risks more or less serious in the sample overseas locations, i.e. Poland, UK, China, Argentina, Mexico? How much would US best practices add to frac'ing costs in these locations?
- To what extent is Community opposition an issue in the sample locations? How much does it add to frac'ing costs? Are the reasons behind European frac'ing moratoriums different than the reasons for Community opposition elsewhere?
- Is the lack of financial benefits for local communities a major factor stoking local opposition? Have any attempts been made to address this issue outside the U.S.?

3:15-5:15 4th Round – Panels on Host Government Policies
Eastern Europe:

The Americas:

Vikram Rao, Advisor to Chief Operating Officer, RTI International

- What issues most impede frac'ing in that location?
- To What extent are these recognized by the government?
- What changes to promote frac'ing have already occurred or are in the works?

7:00-9:00 Speakers-Only Dinner and Address

U.S. Energy Diplomacy and Frac'ing – How America's government has been Discussing frac'ing, energy supply security and prices with foreign governments

Day 2 – Saturday, April 2, 2016

8:30-8:35 Introduction to Day 2 – "What Has to Change"

- A Kenan-Flagler Energy Center representative will summarize the issues identified on Day 1 and introduce the "Case for Change" topics to be discussed on Day 2

8:35-9:30 – Close up on U.K. – 'What a Government "All In for Frac'ing" Plans to do Next'

The challenges of local political opposition and intense regulatory oversight

- Measures to enhance stakeholder engagement and community support

9:35-10:30 5th Round – Close up on China – 'A View from the Front Lines, and from Above'

- Overview of issues constraining Chinese frac'ing, i.e. geology, infrastructure, water, community, environment, fiscal, state of Chinese industry & policy
- Measures adopted since 2012 to promote Chinese frac'ing, protect environment
- What needs to happen to unleash Chinese frac'ing – A Go-Forward Plan

10:40-12:15 "What Has to Change"

Panel Discussion 1: Fiscal Regimes, Market Structures & Price Systems

- How existing fiscal regimes designed for conventional production need to be modified to suit frac'ing's different characteristics
- How to modify price control structures or fiscal treatment of communities

Panel Discussion 2: "The Rest of the Story"

Free ranging discussion on other 'case for change' items, ranging from infrastructure support and freeing up of service markets to revised regulatory structures and oversight

12:15-12:30 Summing Up

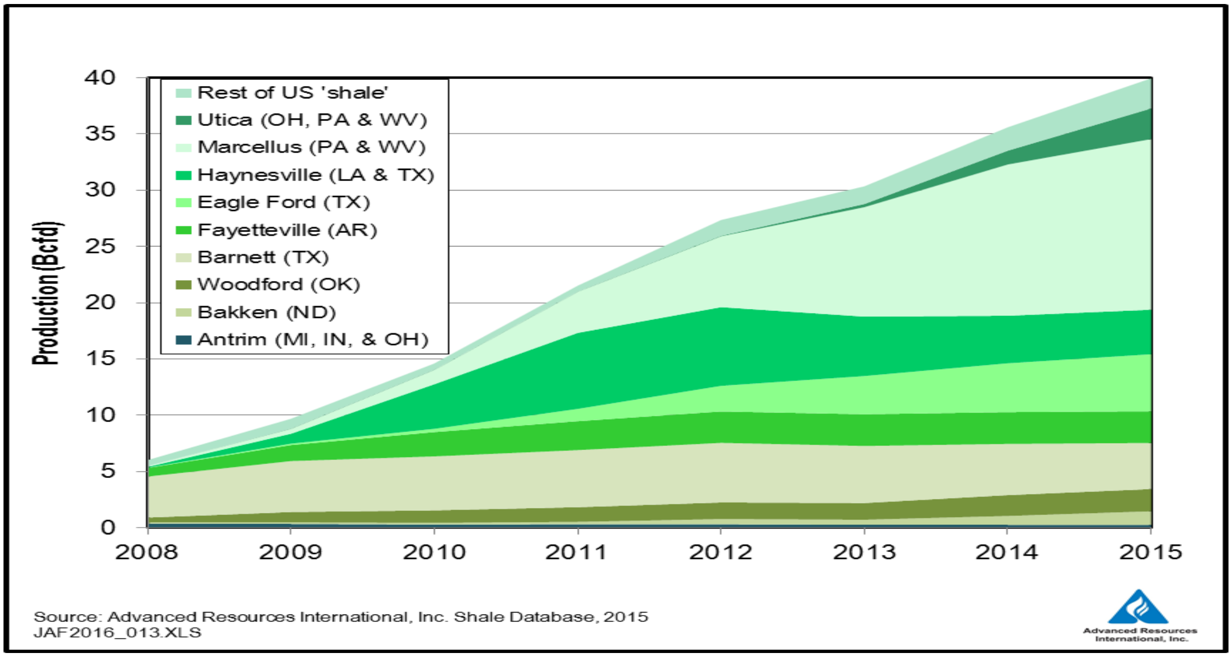
- A Kenan-Flagler Energy Center representative will sum up key findings in terms of Frac'ing's global potential and what needs to happen to unlock it, looking forward to publication of a Conference Report

12:30 Adjourn

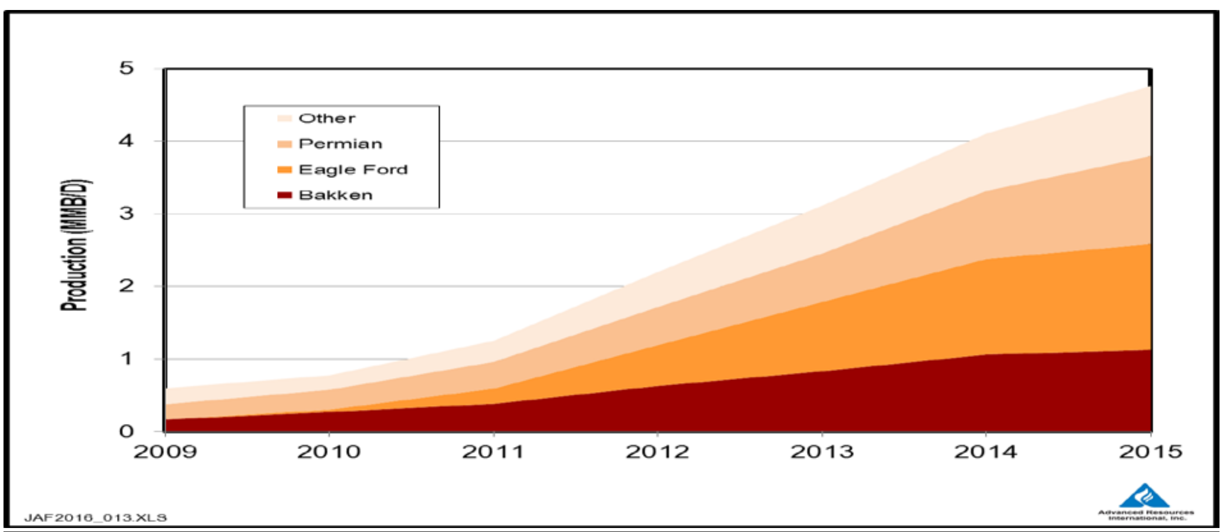
Appendix 2

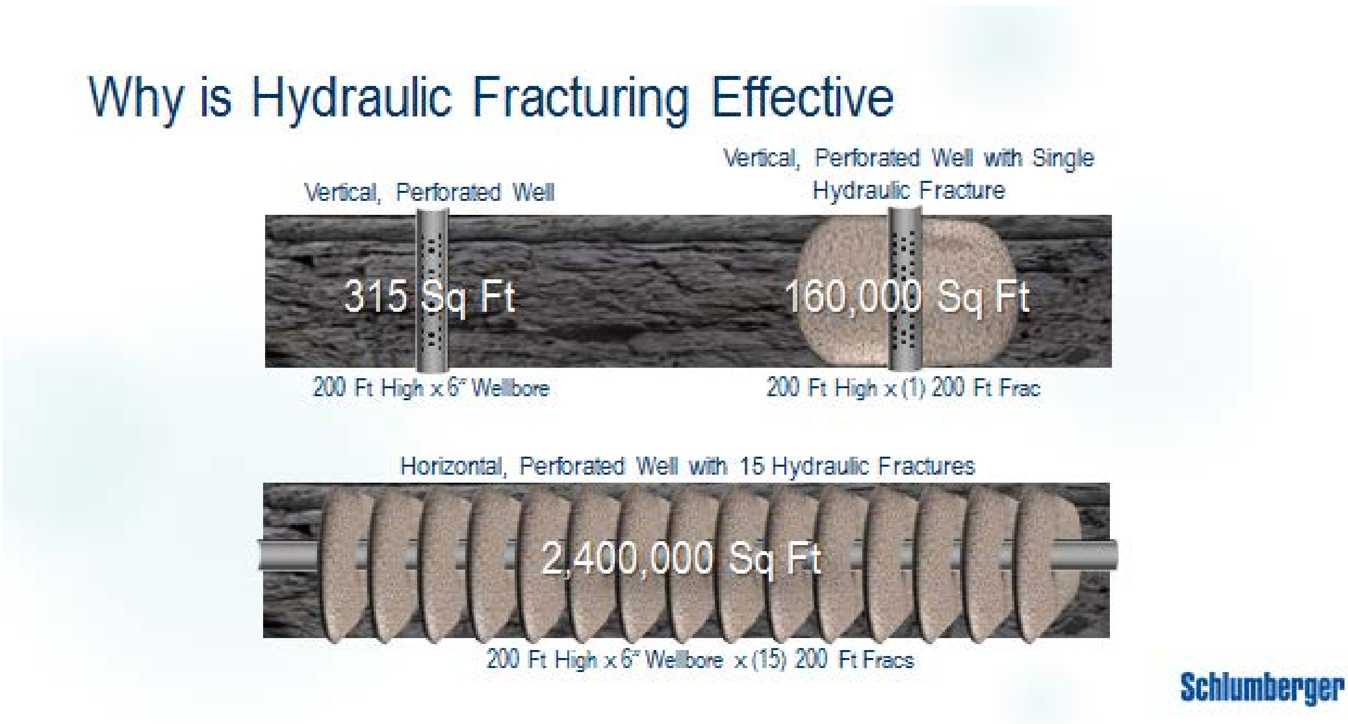
U.S. Shale Production Growth & Learning Curve

U.S. Shale Gas Production (Dry)



U.S. "Tight Oil" Production





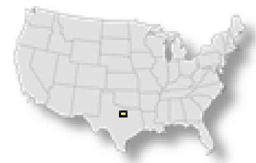
Use of Stacked, Multi-Horizon Hz Wells

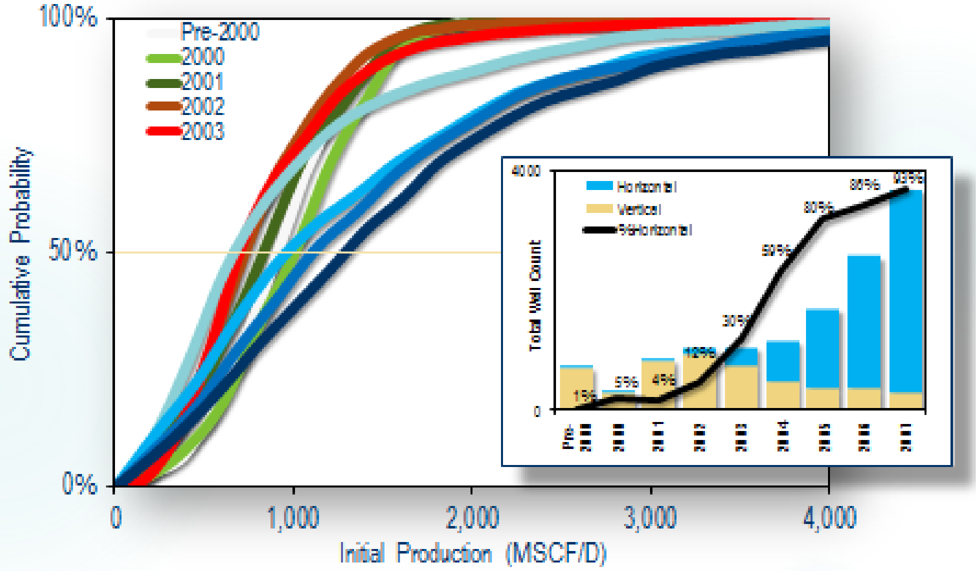
Well Inventory positions ECA for growth beyond 2015

		Tower	Saturn	Dawson South	Gordondale	Pipestone
A/B1	Upper Montney	55	400	380	-	-
B2/B3/C1	Upper Montney	125	293	-	-	-
C2/D/E	Upper Montney	130	402	115	-	-
F/G	Lower Montney	150	435	695	-	337
G	Lower Montney	-	-	-	-	
H	Lower Montney	-	-	-	60	36
Sexsmith		140	415	565	40	177
Total		**600**	**1,945**	**1,755**	**100**	**550**

Source: Encana 2015

The Barnett Learning Curve

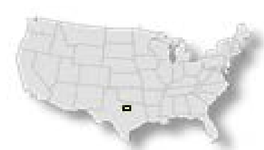


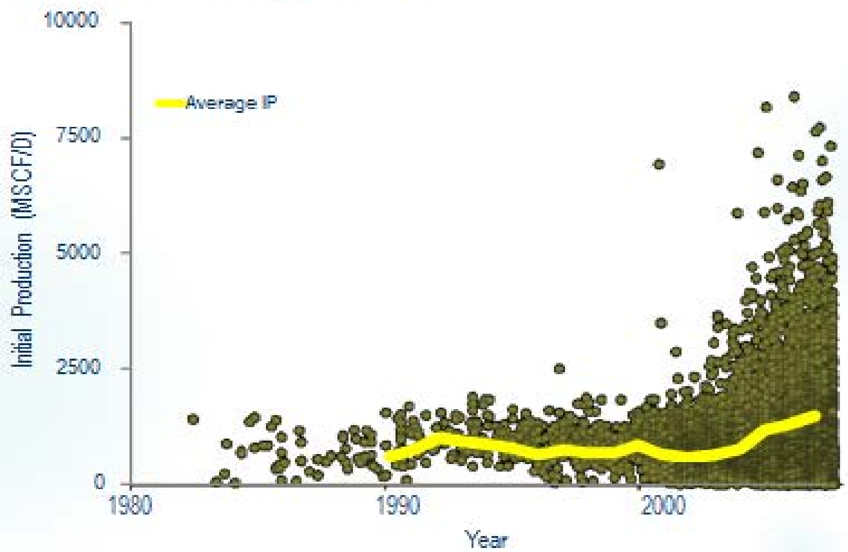


Source: IHS; SLB analysis

Schlumberger

The Barnett Learning Curve





Source: IHS; SLB analysis

Schlumberger

Appendix 3

Alberta Energy Regulator – Mandate and Pilot Studies

Our Mandate

The AER's mandate is to ensure the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources over their entire life cycle. This includes allocating and conserving water resources, managing public lands, and protecting the environment while providing economic benefits for all Albertans.

2

Alberta Energy Regulator

AER

Can make the Regulatory System more Efficient?

12

2. Increasing **Efficiency** in the Regulatory System

- **Area Based Regulation Pilot** (2014)
- Well Density Requirements – Subsurface Order No. 1 Montney and 3 Duverney (2015)
- Updated Directive 017: Measurement Requirements for Oil and Gas Operations (2016)
- Alberta Government is introducing new royalty framework that will harmonize royalties paid by product type to support optimal outcomes by removing distortions

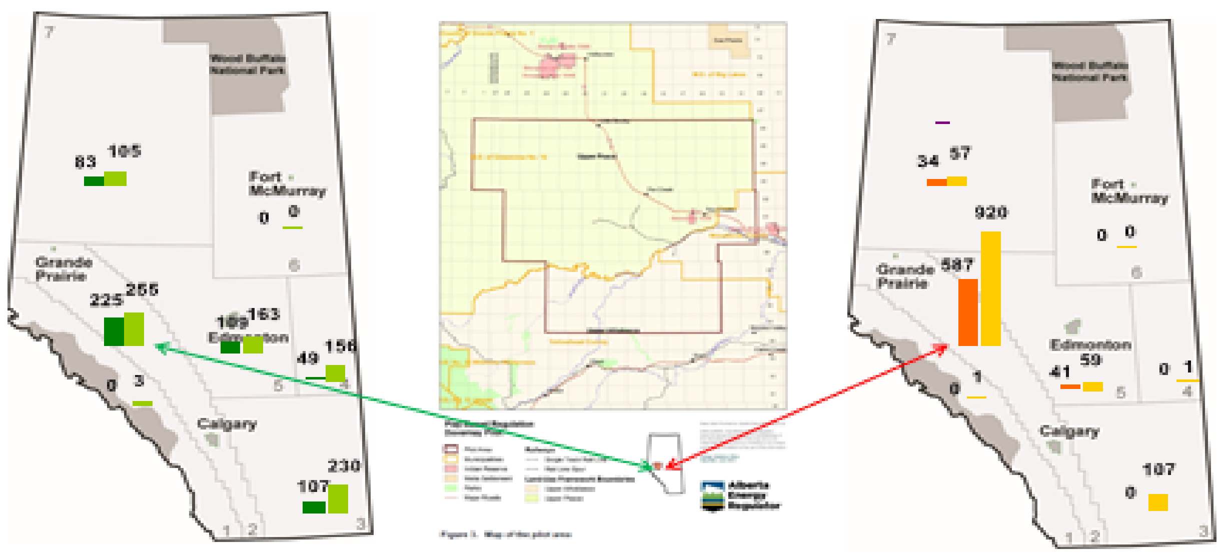
AER

ABR Case Study

- ABR establishes area-based regulatory requirements
- Requirements are suited to the play development **risk profile**
  - Location / setting / valued components
  - Resource characteristics
  - Technology

13

Area Based Regulation was Piloted in an Area where Multistage Horizontal Fracturing is Common



- Horizontal Hydraulic Multistage Oil Wells = 673
- Total Drilled Oil Wells[1] = 912
- Horizontal Hydraulic Multistage Gas Wells = 882
- Total Drilled Gas Wells[1] = 1,146

[1]Includes horizontal and vertical/directional well types.

AER

ABR reduces Regulatory Application Burden

	Current State: types and quantities of applications	ABR
4 Multi- (8) well pads	4 - mineral surface lease app. (PLA) 32 - well license app. (OGCA) 4 - facilities app. (OGCA)	1 – application 1 – notification / consultation 1 – decision For all activities under all statutes
4 Access road	4 – licenses of occupation (PLA)	
5 Water pipeline	5 – pipeline agreements (PLA)	
5 Oil/gas pipeline	5 – pipeline agreements (PLA) 5 – pipeline licenses (OGCA) 2 – pipeline installation leases (PLA)	
1 Water reservoir	1 – license of occupation (PLA) 1 – application to construct reservoir (WA) 1 – application for water intake (WA) 1 – application for dam structure (WA)	
	Other considerations: • Applications submitted as one-offs • All applications require notification & consultation • Initial well production likely trucked if oil with gas flared/vented. Water trucked • No understanding or consideration of cumulative impact • Stakeholder engagement likely fragmented without view to full development	Other considerations • Cumulative impacts understood and assessed • Risk management plans in place • Stakeholder engagement covers full project lifecycle
	• **65 separate authorizations and notifications required**	• **1 authorization and notification required**

Appendix 4

A Model Frac'ing Fiscal Regime

The following Model Regime outlines provisions of a tax system designed to incentivize unconventional development. It incorporates the principles listed in the body of this Report, while leaving blank the specific terms and provisions which the parties would negotiate on a case by case basis.

This framework is based on several initiatives discussed at the conference, i.e. 1) area-specific fiscal regimes customized for local conditions; 2) the integration of environmental and fiscal regimes; and 3) the incorporation of local community incentives into federal or national fiscal regimes.

PREAMBLE

The purpose of this fiscal regime is to provide: 1) a secure fiscal framework for the development of unconventional resources; 2) to encourage the responsible development of said resources; 3) to provide compensation and incentives for communities bearing the impacts of said development; and 4) to provide for a reasonable sharing by the government in the wealth extracted by said development.

This fiscal regime (the Regime) is negotiated among ____________________, the governing tax authority (the Authority) and ____________________, the party seeking to develop resources within the Authority's jurisdiction (the Developer).

The Regime shall pertain only to the area defined by locational parameters_________________ (the Field Area) for which the Developer has obtained a license to explore and produce hydrocarbon resources (the Exploration/Production License, or the License).

The Field Area shall be identical to that governed by Exploration and Operating Regulations negotiated between the Developer and ______________________, the governing environmental regulatory authority (the Regulator).

The Regime shall cover all matters of taxation and government-take, Federal, State and Local for the duration of the Developer's activities and operations in the Field Area, with such period not to be less than ___________________ years from the date of this agreement.

KEY TERMS

Exploratory Drilling: This phase encompasses all wells drilled to delineate the Field Area's potential and determine the Target Sustainable Production (TSP) for this agreement (defined below).

Field Intensity Drilling: This phase encompasses all wells drilled to reach and sustain the Target Sustainable Production.

Field Maintenance Drilling: This phase encompasses all wells drilled to sustain production once either the TSP has been surpassed or a Sustainable Field Production (SFP, defined below) declared, so long as the number of annual wells drilled in the Field does not fall below __________.

Target Sustainable Production: This figure, measured in __________(Oil Barrels per Day, B/D and/or Natural Gas Thousands of Cubic Feet per Day, kcf/d) represents a Field Area production level agreed upon among the Developer and the Authority at which level the Developer believes an efficient, permanent logistical system for delivering production to market will be economically justified.

Baseline Production (BP): That level of production being generated at the end of Exploratory Drilling. The Developer shall declare this production level to the Authority to terminate the Exploratory Drilling phase and the fiscal conditions that attach to that phase.

Field Ramp Production (FRP): This pertains to the additional production being added to Baseline Production such that their combined total is still below the Target Sustainable Production. Developer shall declare the presence of Field Ramp Production to the Authority when it exceeds Baseline Production by ___%

Sustainable Field Production: This pertains to the actual level of production which the Developer is able to sustain through Field Intensity Drilling. If this production level turns out to be less than the Target Sustainable Production, Developer shall advise the Authority that the Target Sustainable Production cannot be achieved. Taxes applicable to the Field shall than apply to the SFP rather than the TSP.

Declaration Date: Refers to the date agreed among the Authority and Developer by which the Developer must have reached TSP or have declared a lower SFP.

Long Tail Production (LTP): This pertains to production from existing wells once the Developer has declared its intention to cease Field Maintenance Drilling or has failed to drill the minimum number of annual wells.

Community Impact Fees: These pertain to fees which the Developer pays to the Authority upon being given the License to perform Exploratory Drilling. The Authority shall make these fees available to the Community for agreed local utilization, as specified in the Developer's License

Exploration Royalty: These royalty payments shall be assessed per each well drilled by the Developer during Exploratory Drilling and paid to the Authority. Additional Exploration Royalties may be assessed on each unit of production sold by the Developer during Exploratory Drilling. The Authority shall make these Royalties available to the Community for agreed local utilization, as specified in the Developer's License. Said Additional Exploration Royalties shall be negotiated among the Authority and the Developer but shall not exceed 5% of the value realized by the Developer on production after transfer of title to a third party. All such Royalties shall cease upon the Developer declaring BP and the end of the Exploration phase.

Developer Cost Recovery: Developer shall bank all pre-exploration and Exploratory Drilling expenses. These can be immediately expensed for tax purposes against revenues generated by BP, FRP and TSP or SFP production. Drilling expenditures and Intangible Drilling Costs incurred during Field Intensity Drilling shall be capitalized or expensed following standard industry practice, and deducted for tax purposes as is customary under the general hydrocarbon fiscal law.

Baseline Production Tax Rate: Should the Developer have taxable income from Baseline Production or any portion thereof during the Exploration phase, Developer shall pay a ______% tax rate on said income, such rate to be negotiated with the Authority but not to exceed 10%

Field Ramp Production Tax Rate: Should the Developer have taxable income from Baseline plus Field Ramp Production, Developer shall pay a ______% tax rate on said income, such rate to be negotiated with the Authority but shall be lower than the Baseline Production Tax rate and shall not exceed 10%

Sustainable Field Production Tax Rate: Should the Developer have taxable income from TSP or SFP Production, Developer shall pay a ______% tax rate on said income, such rate to be negotiated with the Authority but not to exceed 30%, except as described in the Excess Price Surcharge provision below

Long Tail Production Tax Rate: Once the field enters LTP, the Developer shall be liable to pay a tax rate of ________% on taxable income, such rate to be negotiated among the Parties, but must exceed the Sustainable Field Production Tax Rate while not exceeding 35%

Benchmark Price: Refers to a quoted commodity price traded on a public exchange which the Authority and the Developer agree to use, as a reference for implement the price-related terms of this agreement. The parties shall agree on necessary adjustments to the publicly quoted price, such that the Benchmark Price, as adjusted, reflects the price realized by the Developer on sales of its production.

Excess Price: Refers to that portion of price above a ceiling price agreed to by the Authority and the Developer.

Floor Price: Refers to a price agreed to by the Authority and the Developer, below which the Sustainable Field Production Tax Rate will adjust down to a lower level.

Excess Income: Refers to additional income generated by applying the Excess Price to TSP or SFP, as the case may be.

Excess Price Surcharge: Refers to an additional tax rate applied to Excess Income

Abandonment Fund Deposits: Refers to cash deposits which the Developer may make from the proceeds of LTP sales, said deposits to reside in an escrow account with a first class bank approved by the Authority from a list agreed initially among the parties. Deposits to this Abandonment Fund shall be tax deductible, and may only be withdrawn for purposes of Field Restoration following Abandonment.

Abandonment and Restoration: Abandonment shall be deemed to have occurred either when declared by the Developer or when LTP falls below ____________ of annual production. Once Abandonment has occurred, the Developer shall execute the Restoration Plan agreed with the Authority and may draw upon Abandonment Fund Deposits solely for this purpose.

GENERAL PROVISIONS

I. Provisions that take effect upon Developer being granted an Exploration/Production License

- Developer agrees to pay an immediate Community Impact Fee of $________________ and the Authority agrees to make said funds available to the Community for the following agreed purposes_____________________ as specified in the Developer's License.
- Developer agrees to pay Exploration Royalties of $______________ per well drilled and the Authority agrees to make said funds available to the Community for the following agreed purposes_____________________ as specified in the Developer's License.
- Developer agrees to pay Additional Exploration Royalties of $______________ per unit for the following agreed purposes_____________________ as specified in the Developer's License.

II. Provisions that take effect upon the Developer declaring Baseline Production

- Developer shall be liable to pay the Baseline Production Tax Rate on taxable income, if any, from sales of Baseline Production
- Developer shall declare the presence of Field Ramp Production as soon as the combination of Baseline and Field Ramp Production exceeds Baseline Production by ___%
- Developer shall then be liable to pay the Field Ramp Production tax rate of __________% on any taxable income resulting from the combination of Baseline and Field Ramp Production
- Developer shall be allowed to claim Developer Cost Recovery when assessing its tax liability.

III. Provisions that take effect on or before the Declaration Date

- The Developer's production from the Field must either have reached the TSP or the Developer must declare a lower SFP
- The Developer shall then pay the Sustainable Field Production Tax Rate of ____________% on any taxable income generated by sales of the field's production
- The Developer shall be eligible for Developer Cost Recovery
- Should the Developer fail to declare having reached the TSP or indicate a lower SFP by the Declaration Date, it shall then pay the Sustainable Field Production Tax Rate on any taxable income generated by sales of the field's production. In addition, the Developer shall be liable for a retroactive royalty payment of $_____________ per well drilled and $__________________ per unit of Baseline and Field Ramp Production.

IV. Provisions that take effect on or after the Declaration Date

- The Developer shall pay the Sustainable Field Production Tax Rate of ___% on any taxable income generated by sales of the field's production
- The Developer shall be liable to pay an Excess Price Surcharge of _______%, on taxable income resulting from an Excess Price calculated versus a Ceiling Price of $_____________ per unit of production
- Should the Benchmark Price, as adjusted, fall below the Floor Price on average for a period of ________days, the Sustainable Field Production Tax Rate shall be reduced by

__________%. If the Benchmark Price later rises above the Floor Price on average for a period of ________days, the Sustainable Field Production Tax Rate shall return to the level stated in this Agreement.

V. Provisions that take effect once the Field enters Long Tail Production

- The Developer shall be liable to pay the Long Tail Production tax rate of _______% and the Excess Price Surcharge (if applicable) on taxable income.
- The Developer shall be eligible for Developer Cost Recovery
- The Developer may begin to make annual Restoration Fund Deposits, which deposits shall be tax deductible

VI. Provisions that take effect once Abandonment has occurred

- The Developer shall pay any unpaid, final tax liability outstanding
- The Developer shall execute the Abandonment Restoration Plan and may draw upon the Abandonment Fund to do so.

Appendix 5

Abbreviations

b/d	Barrels per Day
kb/d	Thousand Barrels per Day
MB/d	Million Barrels per Day
MBTU	Million British Thermal Units
BCF/d	Billion Cubic Feet per Day
TCF	Trillion Cubic Feet
BCF/d	Billion Cubic Feet per Day
$/b	U.S. Dollars per Barrel
BOE	Barrel of Oil Equivalent
TBD	To Be Determined
PSC	Production Sharing Contract

Appendix 6

**Stephen Arbogast**, Professor the Practice of Finance at University of North Carolina, Kenan-Flagler Business School.

Stephen Arbogast's teaching career has focused on international finance, project finance, business ethics and the business of energy.

He comes to UNC Kenan-Flagler from the C.T. Bauer College of Business at the University of Houston where he was Executive Professor of Finance and received the Bauer College Payne Teaching Excellence Award in 2008.

He served as the treasurer of Exxon Chemical and ExxonMobil Chemical Company from 1997-2004. His Exxon career spanned 32 years and included assignments as finance manager of Esso Brasileira, treasurer of Exxon Capital Corporation and finance director of Esso Standard Thailand.

While treasurer of Chemicals, he was responsible for the financing of Exxon's $40 billion worldwide chemical business. He served on joint venture boards with Exxon partners in Saudi Arabia, Australia and the United States. Over the course of his career, he led or participated in more than $4 billion in capital market and project financing. He also worked in operating affiliates encompassing petroleum refining, petrochemicals, marketing and logistics.

Professor Arbogast has written over 70 case studies which are core teaching materials for his courses. The cases include many transactions he led or participated in during his Exxon career.

He also has written numerous articles on the energy industry and is the author of *Resisting Corporate Corruption*, which offers case studies and essays examining the causes of unethical corporate behavior and the options available to employees for resisting such activities. It includes cases covering Enron from early days until its bankruptcy in 2001, as well as cases on the ethical dilemmas at Countrywide, Fannie Mae, Goldman Sachs, Citigroup, AIG, Lehman Brothers, Bear Stearns and the rating agencies leading up to the financial crisis.

Professor Arbogast has been a member of the National Renewable Fuels Laboratory (NREL) Biofuels Technical Review Panel since 2008. He was principal investigator on a study for NREL entitled "Preferred Paths for Commercializing Pyrolysis Oil at Conventional Refineries" from 2008-2010.

He received a master's degree in public affairs from the Woodrow Wilson School of Public and International Affairs at Princeton University, his BA in government from Cornell University and a master's degree in theological studies from the University of St. Thomas, Houston.

 **Vikram Rao**, Executive Director, Research Triangle Energy Consortium.

Vikram Rao advises the non-profit RTI International, venture capitalist Energy Ventures AS, and firms BioLargo Inc., Global Energy Talent Ltd., Biota Technology Inc., BaseTrace Inc. and Eastman Chemicals Company.

He retired as Senior Vice President and Chief Technology Officer of Halliburton Company in 2008 and followed his wife to Chapel Hill, NC, where she is on the UNC faculty. Later that year he took his current position. He also serves as Chairman of the North Carolina Mining and Energy Commission.

Dr. Rao's book Shale Gas: the Promise and the Peril was released in 2012 by RTI Press and can be found at www.rti.org/shalegasbook. It is written for general audiences and is intended to inform on the heated debate on fracturing for shale gas.

Dr. Rao holds a bachelor's degree in engineering from the Indian Institute of Technology in Madras, India, along with a master's degree and a doctorate in Materials Science and Engineering from Stanford University.

UNC
KENAN-FLAGLER
BUSINESS SCHOOL
ENERGY CENTER

The University *of* North Carolina *at* Chapel Hill
Campus Box 3490, McColl Building, Chapel Hill, NC, 27599-3490

S.V. Arbogast
Director

The UNC Kenan-Flagler Energy Center: At a Glance

Mission: The Center promotes sound energy public policy through balanced programming, unbiased research, and career placement across the energy value chain. We strive to enhance the student experience through career-focused events and conferences, research assistantships, curriculum development, internship assistance, and access to faculty and industry professionals.

Guiding Philosophy: The Center believes in an "All of the Above" approach to energy. We see that national progress and well-being are linked to abundant, affordable energy supplies. The major challenge is to optimize the mix of fuels by taking availability, cost and public goods into account. The Center is especially interested in highlighting the different challenges facing oil & gas and renewables, and the relative progress being made in addressing those hurdles.

Program Activities:

- Major Conferences – Day or multi-day events focusing on major contemporary public policy issues. A conference on Global Unconventional Oil/Gas is planned for 2016, while one on Electricity Storage is planned for 2017.

- Symposia/Panel Discussions – Half-day events bringing industry representatives, government officials and academics together to discuss challenges facing a particular industry or energy company, e.g. integrating renewable electricity supplies into the power grid

- Sponsored Research – The Center will undertake research into energy related topics which are understudied elsewhere. This research will employ MBA students that belong to the Energy Club, and will take advantage of Kenan-Flagler's faculty expertise in finance, accounting and strategy. Examples of sponsored research topics include: 1) whether Wall Street analysts under/over value energy firms due to data gaps in publicly available information; and 2) relative progress among non-U.S. regulatory regimes regarding fracking tight oil/gas resources

- Sponsored Internships – At present only 3% of Kenan-Flagler MBAs take permanent employment in the energy industry. Increasing job placement with energy companies of all stripes is thus a major goal. Internships often are the doorway to full time job offers. Attractive internships sometimes are available on a non-paying basis. The Center seeks to capture these opportunities by offering stipend support to qualifying Kenan-Flagler candidates.

- Public Advocacy – As a result of the above activities, the Center aims to become a respected voice on energy issues, to be consulted by legislators, think-tanks and media, and to publish those of its research findings relevant to contemporary issues.

Upcoming Events:

- Global Unconventional Oil/Gas Conference – Can the success achieved by fracking in the U.S. be achieved elsewhere, e.g. in China, Argentina, Mexico, the U.K. or Eastern Europe? Will fracking be a game changer setting the future price of energy? Can it deliver climate-change benefits greater than its environmental disruptions? What are the most prospective fracking locations outside of the U.S.? This event will explore these questions aided by speakers and panelists from industry, service companies, environmental organizations and government agencies.

- Energy Storage Conference – This conference, tentatively scheduled for late 2017, will explore progress to date in electricity storage technology and its implications for the economics of renewable electricity. A particular focus will be the potential for electricity storage to overcome the "intermittency" of wind/solar power and its attendant requirements for fossil fuel-based backup generation. Depending upon progress in electricity storage, the potential to extend electrification further into motor transportation will also be examined.

Energy Club:

- The Center supports the Kenan-Flagler Energy Club by assisting the Club's leadership in arranging career treks to energy companies and by coaching Energy Concentration students in preparation for case competitions.

- The Center also provides speakers for the Energy Club's educational activities. These include its Energy 101 and Lunch and Learn series. The Center brings frequent guest speakers to campus from energy firms, private equity and energy banking to be featured at Energy Club events.

Website: http://energyatkenan-flagler.com

Contact Us at:

Stephen_Arbogast@kenan-flagler.unc.edu
713 898-2636 (C)

matthew_lebold@kenan-flagler.unc.edu
919 962-6821

UNC
FRANK HAWKINS KENAN
INSTITUTE OF
PRIVATE ENTERPRISE

The Frank Hawkins Kenan Institute of Private Enterprise: At a Glance

Mission: Fundamental to our belief in a free society is an economic system described as "free enterprise" which is dependent upon individual initiative. This encompasses social and ethical standards derived from this system and embodied in a democratic society.

The Frank Hawkins Kenan Institute of Private Enterprise fosters mutual understanding and appreciation between members of the private enterprise sector, the academic community, and their government, and to encourage cooperative efforts among these groups.

The Kenan Institute serves these communities as a national center for scholarly research, joint exploration of issues, and course development all associated with the principal theme of preservation, encouragement, and understanding of private enterprise.

Organization and Operations: The Kenan Institute is part of the Kenan-Flagler Business School at the University of North Carolina at Chapel Hill and draw's on the School's administrative and faculty resources. It offers a number of programs conferences and seminars which bring together the business and academic communities at both the state and national levels.

The Institute works in conjunction with affiliated centers to provide an ongoing forum for information and interaction between business and academia. The Institute involves scholars and executives from across the nation who, having increased their mutual understanding, can work effectively together for the good of the free enterprise system.

Through its education and research activities, the Institute will provide practical solutions to problems faced by private enterprise, contribute to shaping business school curricula, and foster an appreciation of private enterprise in other academic fields from which future generations of business, academic and government leaders will emerge.

Centers and Activities:

Center for Digital Enterprise & Innovation works with large and small private companies, public organizations, and government agencies to navigate the digital revolution that is transforming how the world conducts business. The Center is at the forefront of this transformation. Its mission is straightforward: to help its clients and partners take advantage of new digital technologies and leverage the constant flow of data generated by these technologies in creative and innovative ways.

Center of Sport Business is a premiere academic institute for engaged scholarship of sport business. Under the leadership of Dr. Deborah Stroman, the Center seeks to align with, create, and identify unique opportunities for the improvement and understanding of the vast sport industry. This $350B+ industry that has truly captivated our society - from small rural towns to major urban centers - integrates with virtually every aspect of the economy including advertising, construction, education, entertainment, equipment, finance, food services, manufacturing, media, real estate, retail, technology, and transportation. The Center's applied work focuses on hosting special events, including the nationally-recognized Basketball Analytics Summit, the Carolina Sport Court (a sports "shark tank"), a Speakers Series, and the Global Sports Mentoring Program in partnership with the State Department and ESPNw. The research domain is engaged in the analysis of the social and economic impact of sport in the entire state of North Carolina.

NCGrowth was founded in 2012 to help North Carolina businesses create good jobs and to help communities create sustainable and equitable opportunities for their people. NCGrowth leverages relationships with community and academic partners to support strategic economic development planning in economically struggling regions. NCGrowth conducts applied research and analysis on a broad array of economic trends including sustainable agriculture, renewable energy, and incentive policies. NCGrowth also provides technical assistance to high growth companies.

UNC Center for Competitive Economies is an institutional research Center created and funded by the University of North Carolina in 2004 with a specified mission "to bring the considerable intellectual resources of the University of North Carolina at Chapel Hill to bear on economic development problems in North Carolina, the southeast, the United States, and the world." The Center performs public service and client-sponsored economic research on local, state, national, and international economic issues. Its primary focus is analysis of economic development challenges and opportunities for the citizens of the State of North Carolina. Over the past six years, the Center Director and staff have been Principal Investigators on 40 applied economic research projects with non-profits, local, and state governments, and the North Carolina General Assembly.

Urban Investment Strategies Center & Competitive Economies Idea Lab pursues three sets of activities: (1) building an elder care economy innovations hub, (2) producing research reports for consulting clients, and (3) facilitating leadership/strategy development for its clients. Key to the Center's work is helping North Carolina nurture and grow an innovation economy, conscious of and with concerted efforts to be more inclusive of people of color and women, that will likely yield big socioeconomic dividends.

Technology Commercialization Carolina (TCC) provides support for North Carolina's innovators and inventors through commercialization and entrepreneurship training, early stage venture launch support and funding. Among the many services available through the TCC are patent landscaping, market & funding opportunity research, startup consulting, entrepreneur technical assistance program (E-TAP), and commercialization and entrepreneurship training and workshops.

Upcoming Events:

- "Basketball Analytics Seminar" at Kenan-Flagler Business School, UNC Chapel Hill, on October 7th, 2016. This is a half-day event with attendance capped at 75 participants.

- "Economic Policy Challenges for the Next U.S. Administration" at Kenan Institute of Private Enterprise, UNC Chapel Hill, on October 14, 2016. This is a full-day event with attendance capped at 200 people.

- “Symposium on Crowd Funding North Carolina Economic Development” at Kenan Institute of Private Enterprise, UNC Chapel Hill, on October 21, 2016. This is a half-day event with attendance capped at 50 people.

Website: http://www.kenan-flagler.unc.edu/kenan-institute

Contact us at:

Director,
Gregory_Brown@kenan-flagler.unc.edu
919-962-9250

Executive Director,
Mark_Little@kenan-flagler.unc.edu
919-962-1041