INTERNATIONAL SHALE GAS AND OIL JOURNAL

VOLUME 2 | ISSUE 3 | NOVEMBER 2014

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The International Shale Gas & Oil Journal (ISG&OJ) is a quarterly journal on shale gas and oil developments in politics, economic, regulatory, tax & legal areas for practitioners and academics in the field. The journal draws on the experiences in USA, Canada and China, but the focus is mainly on Europe.

ISG&OJ updates on EU and national level legislation, outcomes of research on shale gas and oil potential by geological national surveys, reviews on developments and perspectives per EU country with a hint of the political state of play, business developments with regard to new market entrants and concessions trading in the EU, conclusions of expert reports released by think tanks, international and national expert organizations, opinions expressed by the EU and governments officials EU and governments officials, lawyers, scientists, IOC's and NOC's, regulators.



**ISSN :** 2214-2320

**Published by :** Claeys & Casteels Law Publishers bv
P.O. Box 2013
7420 AA Deventer
The Netherlands

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3001 Heverlee (Leuven)
Belgium

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www.shalejournal.eu

Publisher: Aernoud Oosterholt

**Subscription info :**

The ISG&OJ is published four times a year
(January, April, July, October)

Subscription price hard copy:
€ 395 per year, excl. VAT/BTW/TVA
including postage and handling.

Subscription price electronic edition:
€ 395 per year excl VAT/BT/TVA
including handling

Combination Subscription Hard Copy &
Electronic edition: € 474 excl. VAT/BTW/TVA
including postage and handling

Multiple use subscription fees on request:
info@claeys-casteels.com

**Citations :** this journal should be cited as follows: 2014/3 ISG&OJ (pages reference)



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# A play for shale: expanding resources in the European Union

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## 1. Introduction

Detractors of potential shale development efforts wield a powerful weapon—public perception. Throughout Europe, decades of commitment to environmental protection coupled with popular mistrust of "big oil" have led to a first response in many communities of "Not here!" Twenty years ago, that might have been a prudent reaction. When the earliest production from the Barnett shale was measured in the United States, experts ranked unconventional resources dismally in the American energy mix, predicting approximately 2% could be expected from these resources.[1]

Such a paltry amount was not worth heavy investment in personnel and equipment, or the risks of environmental disruption and public opposition.

However, that bleak prediction quickly faded - almost as quickly as drilling, fracturing, and environmental technologies were adapted for shale operations. By 2012, the meager 2% had shot up to 35 and 40% for oil and gas, respectively, all produced from major shale plays across the U.S.[2]

Debate regarding the merit of shale development has not subsided much in recent years, despite clear potential economic advantages in terms of energy independence, plentiful jobs, and increased revenue for state and national governments. Yet, while deliberation continues regarding the potential environmental impact on quiet villages unaccustomed to intensive drilling/production operations, the actual "nuts and bolts" aspects of planning a shale development operation should not be ignored.

Helping ensure optimal outcomes for both hydrocarbon production and environmental advocacy requires careful preparation. Proven technologies that can achieve such outcomes are available and, despite the final decision of whether to develop shale plays, the assessment timeline should begin. In the EU, proper planning for shale development should be considered. This consists of preparation for both subsurface data acquisition in addition to the most vital part of planning - surface planning. While both are critical, this becomes a team effort comprised of councils, exploration companies, and service companies.

> *"The 'nuts and bolts' aspects of planning a shale operation should not be ignored."*

## 2. Horizon 2020 LCE-16-2014

Horizon 2020, the EU Framework Programme for Research and Innovation, has launched Project LCE-16-2014, with the stated goal of "understanding, preventing, and mitigating potential environmental impacts and risks of shale gas exploration and exploitation."
The ideal outcome is a collection of best practices with sterling credentials - customized for European conditions.

1 IHS. America's New Energy Future: *The Unconventional Oil and Gas Revolution and the US Economy*. Volume 1: National Economic Contributions. October 2012.

2 US Energy Information Administration. 'Shale gas provides the largest source of growth in the US natural gas supply' and 'Tight oil-driven production growth reduces need for US oil imports.' Available at EIA.gov.

The project description states three concerns that must be addressed:

- better understanding and monitoring of the fracturing process and its environmental effects (including in the long term);
- treatment and recycling of flowback and produced water;
- mitigation of induced seismicity and emissions to air (including greenhouse gases)

These concerns are largely focused on what is observed, measured, and managed on the surface, but all of these things can be controlled and mitigated through thorough and smart subsurface analysis and planning.

### 3. Begin with the reservoir

An operator who enters negotiations to explore and produce a given shale resource has a long path of decision points ahead; even under highly favorable circumstances, the process can take years.
Typically, shale development requires more wells with shorter productive cycles, drilled horizontally through the target to achieve the greatest possible exposure to hydrocarbons in place. Drilling is a top-to-bottom operation involving a rig, tanks, generators, heavy trucks, and small armies of personnel.

However, the true commencement of a drilling project begins much earlier, more quietly, and almost invisibly to most. The most important monetary investment is made during data collection and analyses before any drilling actually occurs.

*"Optimizing well placement significantly impacts well producibility."*

Before the rig moves in, the well pad is built and, even before environmental impact assessment (EIA) begins, the oil company must perform rigorous analysis to help determine if economically viable production exists. Shale geologists and geophysicists are a relatively new breed, representing just one of many differentiators between conventional and unconventional operations. Using better and more advanced technology is fundamental to assessing economic viability before drilling.

Play potential is evaluated initially using non-invasive seismic techniques, and the resulting data is correlated to any existing nearby wells. Specialized seismic analysis, designed for use in unconventional resources, can reveal the areal extent and positioning of the target zone of production. The footprint for seismic operations is small and temporary, but the information gained is put to good use visualizing the rock.

Shale is composed of quartz, carbonate, and clay in relative proportions, and the specific mineralogy impacts "fracturability." Brittle shales are more susceptible and will often shatter when subjected to hydraulic fracturing, making them good candidates for oil and gas extraction. Shales with high clay content are prone to absorb frac energy so that the energy follows existing fractures or faults.[3]

The ability to optimize well placement—a skill acquired during many years of U.S. shale operations—has significant impact on well producibility and the decision to drill. Some of the variables are listed below; the industry now has the means to obtain this type of information accurately.

- maximum reservoir contact;
- volume that can be stimulated;
- estimated ultimate reserves (EUR).

Spacing of the horizontal wells is another aspect of potential production and surface requirements. Properly spaced wells enhance reservoir drainage, and the operator can size each well according to the characteristics of the reservoir, eliminating trial-and-error related to rig size, well profile, and fracturing design.
However, before drilling horizontal production wells, operators can drill a series of vertical wells intended to collect data from seismic-identified sweet spots and previous well information. These sweet spots lie far underneath the earth's surface; the objective is to use technology to safely extract resources while mitigating potential risks to the overall substructure.

Simple vertical wells can be drilled to help evaluate the shale's potential. Core samples of the target formation are brought to the surface to be analyzed. During drilling operations, specific tools are used to measure and qualify formation's potential, including the following:

3 EIA/ARI World Shale Gas and Shale Oil Resource Assessment. EIA 2013 Energy Conference ADVANCED RESOURCES INTERNATIONAL, INC. Washington, DC. June 17, 2013

- mineralogy and geochemistry, which dictates how the shale is best exploited;
- mechanical structure, which aids stimulation design and efficiency;
- oil/gas saturations within the native formation fluids;
- existence/volume of free and bound fluids and related porosities;
- effects of pressure/volume/temperature (PVT).

Small perforations can be shot into areas of natural fractures, or areas deemed prone to easy hydraulic fracturing, using a gas charged stimulation tube system. These perforations can deliver descriptive information about the rock, influencing how hydraulic fracturing should be applied, if at all. Using current technology, operators can insert a few gallons of fluid (5 or less) to help assess production capabilities.

These and other findings, acquired through minimally disruptive drilling operations, can be combined to create a petrophysical workflow model that integrates geochemistry, formation evaluation, and geomechanics to help achieve a full understanding of shale characteristics and "sweet spot" validation.

These findings are input into the earth model for the initial horizontal well. Prudent practice then dictates that the findings from the first horizontal well be applied to the pilot project; from there, such findings are applied to the full field development strategy. At this point, the operator is armed with in-place reserve estimates (is this well economically viable?) and the data required to engineer a fracture stimulation design (can the hydrocarbons be retrieved safely and efficiently?).

## 4. The tip of the iceberg

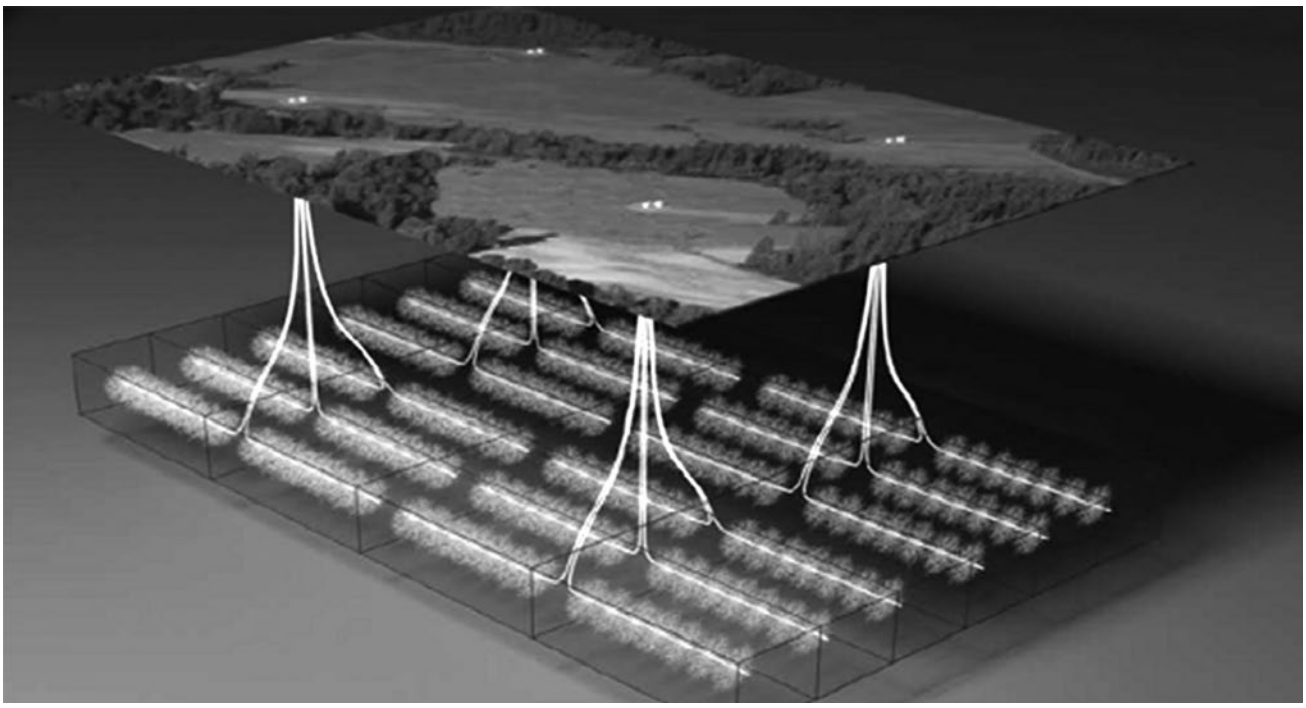
Having properly performed subsurface analysis, well planning, well spacing, and validation of economic legitimacy, operators can turn their attention to the topside. Instead of one pad (drillsite) per well, as illustrated, the operator can design a pad that accommodates multiple wells, all spaced to maximize production, to help avoid wellbore collision and minimize the equipment set needed to drill and complete a shale project.

Drilling tools and equipment now available allow operators to use a single "walking" or sliding rig to drill multiple wells at one site.

Some of the advantages of using this method include:

- less land required;
- fewer roads and pipelines;
- single processing facility;
- minimal urban and wildlife disturbance;
- smaller environmental footprint;
- fewer rig moves;
- consistent regulatory environment.

***Figure 1** - Illustration of shale development from four drilling pads (source: US EIA, reproduced with permission from Statoil).*



The latest trend in pad design further addresses concerns of environmental impact. Operators and service companies are now joining an effort to support what is known as the "super pad" concept. These pads can be less intrusive to the overall community because they use old rock quarries, landfills, or anywhere providing access to the play.
Up to 20 horizontal wells can be drilled from a single pad, allowing access to nearly 40,000 ft of reservoir. In Europe, where mineral rights are largely the property of the state, creating and exploiting a super pad operation is a good option for better efficiency, smaller footprint, and potentially greater hydrocarbon recovery. By contrast, mineral rights in the U.S. are often privately held by landowners; therefore, gaining access to a specific reservoir involves complicated negotiations and the likelihood of a "one lease-one well" rule could apply. Private mineral rights ownership can also limit the length of the lateral drilled.

In short, the EU offers unique opportunities for good surface management that incorporates walking rigs, proper well spacing, and simplified negotiations with government entities for mineral rights.

This approach has been used in the U.S., where some shale operations take place in populous and environmentally sensitive areas.

In support of these operations, operators and service companies in the operating area can agree to share a staging location where most of the required materials and equipment can be stored in adequate quantities. Trucks and pumping equipment can be maintained at this location and dispatched as needed to nearby super pads, as opposed to having trucks and equipment traveling long distances to support individual projects. The centralized staging area could be configured to handle water treatment, proppant storage, maintenance, repair stations, and even personnel camps. This logistical solution significantly reduces traffic through communities and potential safety risks associated with over-the-road transport.

## 5. The water situation

Water is produced along with oil and gas no matter what type of rock drilled. Some have called produced water the oldest challenge in the oilfield because it has no apparent value and must be properly disposed. This produced water tends to be saline and carries with it a cocktail of minerals and organic substances. The following are some reported produced water statistics.

- 11 billion bbl produced annually worldwide;
- 3 to 5 bbl of water produced per bbl of hydrocarbon;
- $51 billion spent annually on water management costs.

Technologies have been introduced that convert the scourge of produced water into a viable source for frac water, which is consumed in high quantities during a typical operation. Initially, the concern was that using produced water as the frac fluid would impair production, but data shows no difference between production rates in similar wells fractured with either fresh or produced water.

The same treatment applied to produced water also works with frac flowback water (the water given back by the rock after the hydraulic fracture is complete). Flowback water accounts for approximately 30% on average of the total amount of frac fluid used.

One issue related to recovering and reusing produced or flowback water is the rate at which it can be treated. Now, a comparatively small mobile unit using electrocoagulation can treat water at rates of up to 26,000 bbl/d with minimal power. If more treated water is necessary, multiple mobile units can be operated simultaneously at the same location.

The electrocoagulation system destabilizes and coagulates suspended colloidal solids in water. Gas bubbles are injected to attach to the coagulated matter so that it floats to the surface to be removed by a skimmer. Heavier coagulants sink to the bottom, leaving clear water suitable for use in drilling and production operations. The mobile treatment unit has a small footprint and is ideally suited for the super pad/multiwell pad model. The ability to use and reuse treated water can result in reduced transportation and disposal costs, fewer emissions from trucking, and, most importantly, it can relieve pressures associated with water supply sources being shared by the community and other industries.

## 6.What goes into frac fluid

A major concern in opposition of fracturing is fear of the chemicals used to prepare fracturing fluid for injection.

The role of a stimulation (frac) fluid is to place a proppant (sand particles) that holds the induced fractures open so that oil or gas can flow from the rock to the wellbore. Studies and fracture design data consistently confirm that a typical fracturing fluid is 99.51% water and sand, with the remaining 0.49% composed of various chemicals to improve fracture efficacy, prevent contamination, and help protect downhole production equipment from corrosion and early failure.

Any additive proposed for use in Europe must be recorded in the European Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH) register and comply with all regulations.[4] REACH compliance should be a sufficient guarantee that additives will not adversely affect health or the environment.

However, if opposition to fracturing remains, there are options that eliminate the "perceived harmful" chemicals, such as the following described technology.

## 7. Sourced-from-the-food-Industry (SFI) fracturing fluid

Further improvements have been made to frac fluids, going beyond water treatment and reuse, related to the actual composition of the fluid. In response to stringent regulatory requirements to disclose the chemicals used in frac fluids and provide assurance that these chemicals pose minimal threat to surface water, a fluid comprised solely of components sourced from the food industry has been tested and introduced within the field.

The primary role of any frac fluid is to deliver proppant to fractures and ensure it remains in place. Therefore, the frac fluid must have reliable carrying capacity in both static and dynamic conditions. This capacity is derived from the addition of a gelling agent or agents.

The results illustrate that proppant-transport performance does not need to be sacrificed when using a fluid system comprised of food industry components. The new sourced-from-the-food-industry (SFI) fluid was subjected to five different methods for measuring its ability to transport and support proppant, along with three other conventional frac fluids.

*"Exposing frac fluid to ultraviolet light before it's pumped downhole can eliminate biocide use."*

The crosslinked gel sourced solely from the food industry exhibited a dramatic difference because it was able to support proppant under static and dynamic conditions.

When applied in actual field operations, the SFI system demonstrated excellent performance in terms of pumpability, proppant transport, and conductivity within the propped fractures.[5] Certainly, this provides a positive option to fracturing opponents who fear chemical toxicity in frac fluid.

The chemicals themselves have been traditionally added to frac fluid by means of a hydrocarbon-based liquid carrier, and this led to concern regarding hydrocarbon contamination of water sources. To overcome this, frac fluid blending units can now be equipped with dry polymer blenders that mix the chemicals into water along with the gelling agent. The hydrocarbon-based carrier is no longer necessary because the dry polymer blender can be used with any frac fluid.

Possibly the most worrisome constituent among the half percent of added chemicals is biocide, which is toxic to downhole bacteria. If bacteria are allowed to flourish, they can "sour" the well by producing highly dangerous hydrogen sulfate (H2S) gas, which poses a threat to humans and is known to damage metals irreparably. Although it is highly unlikely that a biocide (or any additive) used in frac fluid will ever reach the near-surface water reservoirs that serve communities, a perceived risk exists that hydraulic fracturing could accidentally deliver poison to water supplies.

Before moving to a discussion of non-chemical options for biocidal treatment, it is important to note that extensive analysis on thousands of shale wells in the U.S. produced the following findings[6]:

- The vertical fracture height in deep wells is no more than a few hundred feet above the target reservoir, therefore thousands of feet below any freshwater-bearing formations that could contribute water for surface use.
- Among properly constructed wells, there is no documented case of water contamination resulting from fracturing operations occuring 2,000 ft or more below the freshwater-bearing formation.

Even with these findings, it is in the interest of operators and the public alike to minimize any risk imposed by chemical additions to frac fluid. Several technologies have emerged to meet this challenge. One has been recognized by the industry as highly effective and environmentally benign, to the extent that it received a

4 Muñoz-Conde, Juan Carlos. 'The chemistry of fracking.' Espana. 28 April 2014.

5 Loveless, D., et al. 2011. 'Fracturing fluid comprised of components sourced solely from the food industry provides superior proppant transport.' SPE 147206 presented at the SPE ATCE, Denver, Colorado. 1 November.

6 King, G. 2012. 'Hydraulic Fracturing 101.' SPE 152596 presented at the SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas. 6-8 February.

prestigious industry award for dramatically improving health, safety, and environment (HSE) conditions.

The treatment applies ultraviolet (UV) light on-the-fly to frac fluid at rates up to 100 bbl/min, again using a mobile unit for this purpose. The greatest efficacy is gained by treating the fluid immediately before pumping it downhole, thus eliminating the need for biocides altogether. The same system can be used to pretreat fluid that will be stored for later use, but this will require a small supplemental concentration of chemical biocide.

Ultraviolet light has been used as a disinfectant in other industries for years, but never in the harsh field environment encountered during fracturing operations. Now, proven as field-ready and reliable, the technology works by accurate control of UV bulbs, determining the amount of light required based on the turbidity of water being treated, and determining the extent of effectiveness of the disinfection.

A large independent operator in the U.S. incorporated this UV treatment method on a shale gas well to determine if it, along with other "green" fracturing technologies, could make a positive difference. More than 4.8 million gallons of fluid were treated on a single well, eliminating the need for more than 2,400 gallons of chemical biocides.

## 8. Microseismicity: risk identification and mitigation

To address the third concern listed by the Horizon 2020, another look at the findings presented in the now iconic paper, "Hydraulic Fracturing 101: What Every Representative, Environmentalist, Regulator, Reporter, Investor, University Researcher, Neighbor and Engineer Should Know About Estimating Frac Risk and Improving Frac Performance in Unconventional Gas and Oil Wells" (King 2012), will be helpful.
Extensive research into United States Geological Service (USGS) data shows no connection between hydraulic fracturing and damaging earthquakes, although an induced fracture along an existing natural fault can create enough impact to actually register on instruments located near fracturing sites.

Purposeful monitoring of seismicity related to hydraulic fracturing has yielded the following data on magnitudes. In naturally non-faulted rock, the recorded range is -4.0 to -1.0; whereas, in a faulted formation, the magnitude can reach -0.5. By comparison, a typical 6.0 magnitude earthquake releases one billion times more energy than the "stronger" -0.5 tremor associated with fracturing in a faulted formation.

In the U.S., where small (magnitude of 3.0 of 4.7) earthquakes occurred in Arkansas and were perceived to result from hydraulic fracturing, downhole instruments installed to measure the impact of fracturing at the actual site were in the -3 to -1 range. This is the equivalent of 50 million times less magnitude for the -3 measurement, and 500,000 times less for the -1 measurement, per USGS calculations. For comparison purposes, a magnitude 3.0 earthquake is described by the USGS as causing "vibrations similar to the passing of a truck."
Even so, protective measures should be taken, and these are best executed in the well planning stage using 3D seismic technology to help identify the location and direction of "at risk" fault structures. The wells can then be located a safe distance from these faults, and the fracturing design can help account for any potential risk. This type of planning and analysis, coupled with the statistical remoteness of triggering a recordable seismic reaction, has allowed extensive hydraulic fracturing to occur safely in the U.S.

A detailed geotechnical seismology evaluation should include the following areas:

- site geology and soil conditions
  - liquefied sands
  - quick sensitive sands
  - thick deposits of soft soils overlying rock
- seismic design parameters
  - peak ground acceleration (PGA)
  - peak ground velocity (PGV)
  - peak ground displacement (PGD)
- possibility for permanent displacement (could impact pipelines)

Keep in mind that fracturing operations include sensitive instrumentation to track the reach and pressure exerted, and these instruments are proven to also detect indicators of microseismic reactions. Therefore, during a given fracturing operation, the operator has the data available necessary to make decisions concerning seismicity risks. Oversight in this area from regulatory agencies and local seismic specialists will no doubt be part of the shale exploitation package in EU shale developments.

## 9. Emission control

The broad topic of emissions, as related to shale exploration, overlaps into general practices now used to help prevent or minimize unwanted emissions. In view of the strict regulations currently enforced in the EU, long considered a world leader in environmental quality and protection, it is doubtful that anything, such as a renegade shale driller, could escape scrutiny and penalties, or ever reach the point of actually causing harm. Additionally, any knowledge transfer originating from the U.S. on shale exploitation will include the full spectrum of HSE criteria because many U.S. shale developments are located in populous areas and fall under the close watch

of community, state, and federal oversight.
Still, it is worth listing the key areas that require monitoring, and potential operators can evaluate their practices and all associated materials and equipment to help ensure they meet or preferably exceed established standards.

- air quality
  - air emissions produced by the equipment required to extract, process, and transport shale gas
  - potential for increased greenhouse gas (GHG) emissions
- general environmental and health and safety
  - minimizing potential soil contamination
  - eliminating potential increased human health or ecological risks
  - managing noise levels and lighting emissions to help prevent impacting surrounding communities

For shale operations, in particular, the following specific points should be part of the emissions management plan:

- combustion emissions from trucks and drilling equipment;
- combustion emissions from stationary heat or power generation;
- emissions from natural gas processing and transportation;
- evaporative emissions from wastewater ponds;
- emissions attributed to spills of drilling or fracturing fluids.

Currently, equipment, trucks, materials, packaging, and transport methods are all evaluated for HSE (and therefore emission) characteristics. Many truck fleets have converted to natural gas fuel, and heavy vehicles requiring diesel have access to fuels modified for less emissions, and improved air quality and operating efficiencies.

Fluids and oils recovered during operations, such as base oil recovered from drilling fluid waste management practices, can be reused for further downhole operations or to provide an energy source for mechanical facilities.

Because water is the primary element in fracturing, water impoundments, such as ponds or pits, are placed at or near the wellsite. These water storage areas should be designed by licensed engineers and comply with regulatory permitting requirements. Typical components of an impoundment design should reflect the following:

- site geology and soil conditions;
- preparation of sub-base and compaction;
- double lining with a runway;
- underdrain catch basin with a leak detection system;
- fill/withdrawal manifold;
- solids and condensate capture;
- aeration system to reduce bacteria buildup;
- bird netting (if required);
- remote level monitoring system (solar powered);
- security fencing;
- installer's qualifications and work practices;
- construction inspection/certification requirements.

When properly constructed, the important benefit of centralized impoundments and pipelines is the reduced truck traffic associated with transporting water for drilling and fracturing operations. This helps reduce roadway congestion and damage, air emissions, and greenhouse gas accumulations.

Limiting noise pollution within or near communities is a current practice in most EU locations. This is typically accomplished by the installation of temporary or permanent noise barriers, depending on the nature of the operation and related facility.

The bottom line is that any company wishing to launch shale production operations in the EU must comply with existing regulations. All emissions must be monitored, measured, and reported for review; and, if corrections are required, these must be carried out before operations can continue. If the operator will be using contractors or equipment imported from non-EU nations, the operator is responsible for complying with EU standards.

These are the simple, straightforward conditions for permission to work in the EU. There are no shortcuts, nor should there be. In the last 30 years, the oil and gas industry has rigorously policed itself in terms of HSE performance. That self-policing has served two objectives—protecting human health and the environment and protecting the right to work throughout the world. Reputable operators prize their reputations and insist that all service companies supporting their work demonstrate high levels of HSE compliance backed

*"Slightly over 100 land rigs currently operate in Europe, and few are capable of deep horizontal operations"*

by thoughtful policies and standards. Considering the millions of feet drilled and produced by oil companies worldwide, often, under very challenging and technically complex conditions, HSE incidents are extremely low. The universal industry goal is to reach zero incidents, and this attitude is evident from the top down and the bottom up for every employee.

## 10. Lead time

As a backdrop to all the careful planning and execution strategies described, one must keep in mind that, while the U.S. has 1800+ land rigs currently operating, nearly half of which are horizontal drilling capable, only a little more than 100 land rigs are currently operating in Europe; of these, very few are capable of deep horizontal operations.[7]

Further, the majority of hydraulic fracturing equipment is located in North America, and these tools of the trade are not sitting idle, waiting to be exported overseas. They maintain a very high level of usage to keep pace with U.S. operations.

7 Hsieh, Linda. 'European shale gas: a long road ahead.' Drilling Contractor Magazine (International Association of Drilling Contractors). July/Aug 2011.

The EU countries that have already joined the shale revolution are aware of these conditions; and their planning accounts for lead times, equipment supply, knowledge transfer among personnel, and all broad logistical challenges that can and must be overcome to expedite drilling and production.

As in the U.S., once oil and gas begins to flow from shale operations, participating countries will encounter the same downstream issues; the shale boom has created an urgent need for expansion of refining facilities and infrastructure to keep pace with production. For that production do its intended work – create energy independence, abundant jobs and a boost in revenues to the state – the processing and distribution implications must also be part of strategic planning.

In summary, proper planning must occur for every unconventional play. Having the understanding from data acquisition to logistics of truck movements is essential. It truly requires a team effort to help ensure the proper technology, people, and processes are in place.
PLAN THE WORK, WORK THE PLAN.