HYDRAULIC FRACTURING

History of

AN ENDURING TECHNOLOGY

Carl T. Montgomery and Michael B. Smith, NSI Technologies

Editor's note: In 2006, SPE honored nine pioneers of the hydraulic fracturing industry as Legends of Hydraulic Fracturing. Claude E. Cooke Jr., Francis E. Dollarhide, Jacques L. Elbel, C. Robert Fast, Robert R. Hannah, Larry J. Harrington, Thomas K. Perkins, Mike Prats, and H.K. van Poollen were recognized as instrumental in developing new technologies and contributing to the advancement of the field through their roles as researchers, consultants, instructors, and authors of ground-breaking journal articles.

Following is an excerpt from SPE's new Legends of Hydraulic Fracturing CDROM, which contains an extended overview of the history of the technology, list of more than 150 technical papers published by these industry legends, personal reflections from a number of the Legends and their colleagues, and historic photographs. For more information on the CDROM, please go to http://store.spe.org/Legendsof-Hydraulic-Fracturing-P433.aspx.

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Since Stanolind Oil introduced hydraulic fracturing in 1949, close to 2.5 million fracture treatments have been performed worldwide. Some believe that approximately 60% of all wells drilled today are fractured. Fracture stimulation not only increases the production rate, but it is credited with adding to reserves–9 billion bbl of oil and more than 700 Tscf of gas added since 1949 to US reserves alone–which otherwise would have been uneconomical to develop. In addition, through accelerating production, net present value of reserves has increased.

Fracturing can be traced to the 1860s, when liquid (and later, solidified) nitroglycerin (NG) was used to stimulate shallow, hard rock wells in Pennsylvania, New York, Kentucky, and West Virginia. Although extremely hazardous, and often used illegally, NG was spectacularly successful for oil well "shooting." The object of shooting a well was to break up, or rubblize, the oil-bearing formation to increase both initial flow and ultimate recovery of oil. This same fracturing principle was soon applied with equal effectiveness to water and gas wells.

In the 1930s, the idea of injecting a nonexplosive fluid (acid) into the ground to stimulate a well began to be tried. The "pressure parting" phenomenon was recognized in well-acidizing operations as a means of creating a fracture that would not close completely because of acid etching. This would leave a flow channel to the well and enhance productivity. The phenomenon was confirmed in the field, not only with acid treatments, but also during water injection and squeeze-cementing operations.

Fig. 1—In 1947, Stanolind Oil conducted the first experimental fracturing in the Hugoton field located in southwestern Kansas. The treatment utilized napalm (gelled gasoline) and sand from the Arkansas River.

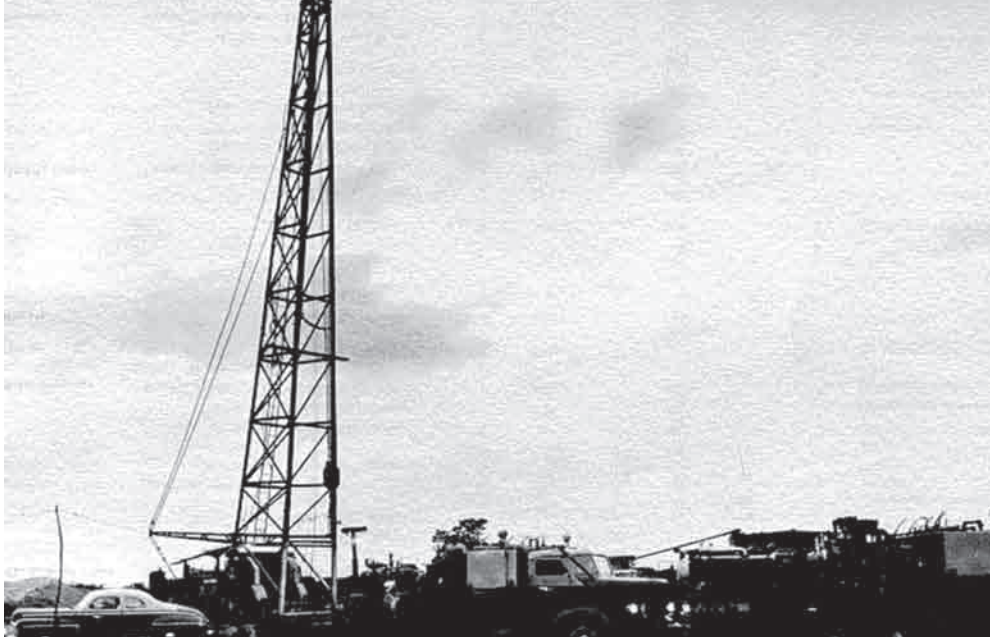

Fig. 2—On 17 March, 1949, Halliburton conducted the first two commercial fracturing treatments in Stephens County, Oklahoma, and Archer County, Texas.

But it was not until Floyd Farris of Stanolind Oil and Gas Corporation (Amoco) performed an in-depth study to establish a relationship between observed well performance and treatment pressures that "formation breakdown" during acidizing, water injection, and squeeze cementing became better understood. From this work, Farris conceived the idea of hydraulically fracturing a formation to enhance production from oil and gas wells.

The first experimental treatment to "Hydrafrac" a well for stimulation was performed in the Hugoton gas field in Grant County, Kansas, in 1947 by Stanolind Oil **(Fig. 1).** A total of 1,000 gal of naphthenic-acid-and-palm-oil- (napalm-) thickened gasoline was injected, followed by a gel breaker, to stimulate a gas-producing limestone formation at 2,400 ft. Deliverability of the well did not change appreciably, but it was a start. In 1948, the Hydrafrac process was introduced more widely to the industry in a paper written by J.B. Clark of Stanolind Oil. A patent was issued in 1949, with an exclusive license granted to the Halliburton Oil Well Cementing Company (Howco) to pump the new Hydrafrac process.

Howco performed the first two commercial fracturing treatments–one, costing USD 900, in Stephens County, Oklahoma, and the other, costing USD 1,000, in Archer County, Texas–on March 17, 1949, using lease crude oil or a blend of crude and gasoline, and 100 to 150 lbm of sand **(Fig. 2).** In the first year, 332 wells were treated, with an average production increase of 75%. Applications of the fracturing process grew rapidly and increased the supply of oil in the United States far beyond anything anticipated. Treatments reached more than 3,000 wells a month for stretches during the mid-1950s. The first one-half-million-pound fracturing job in the free world was performed in October 1968, by Pan American Petroleum Corporation (later Amoco, now BP) in Stephens County, Oklahoma. In 2008, more than 50,000 frac stages were completed worldwide at a cost of anywhere between USD 10,000 and USD 6 million. It is now common to have from eight to as many as 40 frac stages in a single well. Some estimate that hydraulic

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Fig. 3—A 1955 frac pump manufacturing facility. These remotely controlled pumps were powered by 1,475 hp surplus Allison aircraft engines used during World War II.

fracturing has increased US recoverable reserves of oil by at least 30% and of gas by 90%.

Fluids and Proppants

Soon after the first few jobs, the average fracture treatment consisted of approximately 750 gal of fluid and 400 lbm of sand. Today treatments average approximately 60,000 gal of fluid and 100,000 lbm of propping agent, with the largest treatments exceeding 1 million gal of fluid and 5 million lbm of proppant.

Fluids

The first fracture treatments were performed with a gelled crude. Later, gelled kerosene was used. By the latter part of 1952, a large portion of fracturing treatments were performed with refined and crude oils. These fluids were inexpensive, permitting greater volumes at lower cost. Their lower viscosities exhibited less friction than the original viscous gel. Thus, injection rates could be obtained at lower treating pressures. To transport the sand, however, higher rates were necessary to offset the fluid's lower viscosity.

With the advent in 1953 of water as a fracturing fluid, a number of gelling agents were developed. The first patent (US Patent 3058909) on guar crosslinked by borate was issued to Loyd Kern with Arco on October 16, 1962. One of the legends of hydraulic fracturing, Tom Perkins, was granted the first patent (US Patent 3163219) on December 29, 1964 on a borate gel breaker. Surfactants were added to minimize emulsions with the formation fluid, and potassium chloride was added to minimize the effect on clays and other water-sensitive formation constituents. Later, other clay-stabilizing agents were developed that enhanced the potassium chloride, permitting the use of water in a greater number of formations. Other innovations, such as foams and the addition of alcohol, have also enhanced the use of water in more formations. Aqueous fluids such as acid, water, and brines are used now as the base fluid in approximately 96% of all fracturing treatments employing a propping agent.

In the early 1970s, a major innovation in fracturing fluids was the use of metal-based crosslinking agents to enhance the viscosity of gelled water-based fracturing fluids for higher-temperature wells. It is interesting to note that the chemistry used to develop these fluids was "borrowed" from the plastic explosives industry. An essential parallel development meant fewer pounds of gelling agent were required to obtain a desired viscosity. As more and more fracturing treatments have involved high-temperature wells, gel stabilizers have been developed, the first of which was the use of approximately 5% methanol. Later, chemical stabilizers were developed that could be used alone or with the methanol.

Improvements in crosslinkers and gelling agents have resulted in systems that permit the fluid to reach the bottom of the hole in high-temperature wells prior to crosslinking, thus minimizing the effects of high shear in the tubing. Ultraclean gelling agents based on surfactant-association chemistry and encapsulated breaker systems that activate when the fracture closes have been developed to minimize fracture-conductivity damage.

Proppants

The first fracturing treatment used screened river sand as a proppant. Others that followed used construction sand sieved through a window screen. There have been a number of trends in sand size, from very large to small, but, from the beginning, a –20 +40 US-standard-mesh sand has been the most popular, and currently approximately 85% of the sand used is this size. Numerous propping agents have been evaluated throughout the years, including plastic pellets, steel shot, Indian glass beads, aluminum pellets, high-strength glass beads, rounded nut shells, resin-coated sands, sintered bauxite, and fused zirconium.

The concentration of sand (lbm/fluid gal) remained low until the mid-1960s, when viscous fluids such as crosslinked water-based gel and viscous refined oil were introduced. Large-size propping agents were advocated then.

The trend then changed from the monolayer or partial monolayer concept to pumping higher sand concentrations. Since that time, the

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Fig. 4—Early screw-type sand blender.

Fig. 5—Modern fluid/proppant blender or proportioning unit.

concentration has increased almost continuously, with a sharp increase in recent years. These high sand concentrations are due largely to advances in pumping equipment and improved fracturing fluids. Now it is not uncommon to use proppant concentrations averaging 5 to 8 lbm/gal throughout the treatment, with a low concentration at the start of the job, increased to 20 lbm/gal toward the end of the job.

Pumping and Blending Equipment

Hydraulic horsepower (hhp) per treatment has increased from an average of approximately 75 hhp to more than 1,500 hhp. There are cases where, with as much as 15,000 hhp available, more than 10,000 hhp was actually used, in stark contrast with some early jobs, where only 10 to 15 hhp was employed. Some of the early pump manufacturing facilities made remotely controlled pumps powered by surplus Allison aircraft engines used during World War II **(Figs. 3, 6).**

Initial jobs were performed at rates of 2 to 3 bbl/min. This increased rapidly until the early 1960s, when it rose at a slower rate, settling in the 20 bbl/min range (even though there were times when the rate employed in the Hugoton field was more than 300 bbl/min). Then in 1976, Othar Kiel started using high-rate "hesitation" fractures to cause what he called "dendritic" fractures. Today, in the unconventional shale-gas plays, Kiel's ideas are used where the pump rates are more than 100 bbl/min. Surface treating pressures sometimes are less than 100 psi, yet others may approach 20,000 psi.

Conventional cement- and acid-pumping equipment was used initially to execute fracturing treatments. One to three units equipped with one pressure pump delivering 75 to 125 hhp were adequate for the small volumes injected at the low rates. Amazingly, many of these treatments gave phenomenal production increases. As treating volumes increased, accompanied by a demand for greater injection rates, special pumping and blending equipment was developed. Development of equipment including intensifiers, slinger, and special manifolds continues. Today, most treatments require that service companies furnish several million dollars' worth of equipment.

For the first few years, sand was added to the fracturing fluid by pouring it into a tank of fracturing fluid over the suction. Later, with less-viscous fluid, a ribbon or paddle type of batch blender was used. Shortly after this, a continuous proportioner blender utilizing a screw to lift the sand into the blending tub was developed **(Fig. 4).** Blending equipment has become very sophisticated to meet the need for proportioning a large number of dry and liquid additives, then uniformly blending them into the base fluid and adding the various concentrations of sand or other propping agents. **Fig. 5** shows one of these blending units**.**

To handle large propping-agent volumes, special storage facilities were developed to facilitate their delivery at the right rate through the fluid. Treatments in the past were conducted remotely but still without any shelter. Today, treatments have a very sophisticated control center to coordinate all the activities that occur simultaneously.

Fig. 6—Vintage 1950s remotely controlled frac pumper powered by surplus WWII Allison aircraft engines.

Fracture-Treatment Design

The first treatments were designed using complex charts, nomographs,

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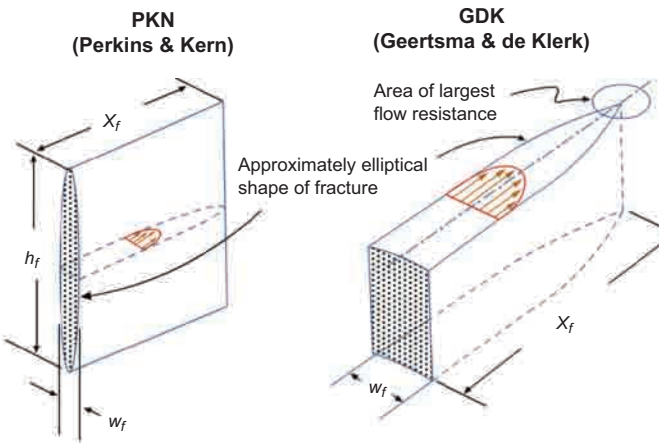


Fig. 7—Early 2D fracture-geometry models.

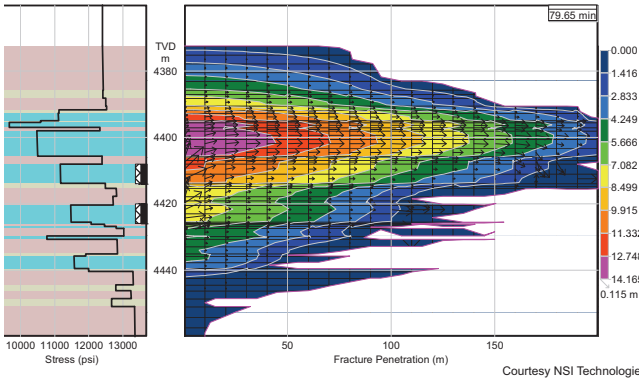
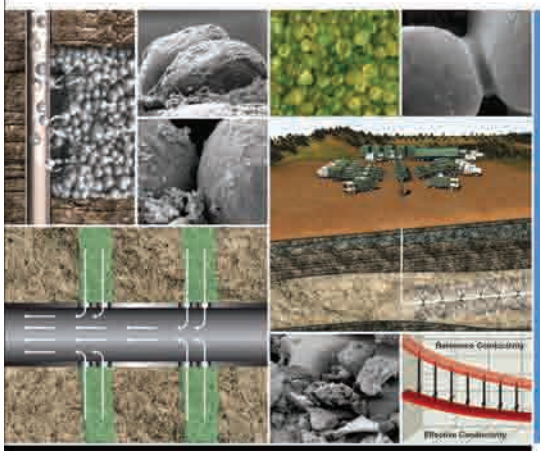


Fig. 8—Modern fully gridded frac model showing fluid and proppant vectors.

and calculations to determine appropriate size, which generally was close to 800 gal (or multiples thereof) of fluid, with the sand at concentrations of 0.5 to 0.75 lbm/gal. This largely hit-or-miss method was employed until the mid-1960s, when programs were developed for use on simple computers. The original programs were based on work developed by Khristianovic and Zheltov (1955), Perkins and Kern (1961), and Geertsma and de Klerk (1969) on fluid efficiency and the shape of a fracture system in two dimensions **(Fig. 7).** These programs were a great improvement but were limited in their ability to predict fracture height.

As computer capabilities have increased, frac-treatment-design programs have evolved to include fully gridded finite-element programs that predict fracture geometry and flow properties in three dimensions **(Fig. 8).** Today, programs are available to obtain a temperature profile of the treating fluid during a fracturing treatment, which can assist in designing the concentrations of the gel, gel-stabilizer, breaker, and propping-agent during treatment



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stages. Models have been developed to simulate the way fluids move through the fracture and the way the propping agent is distributed. From these models, production increases can be determined. Models can also be used to historically match production following a fracturing treatment to determine which treatment achieved which actual result. New capabilities are currently being developed that will include the interaction of the induced fracture with natural fractures.

One of the hydraulic fracturing legends, H.K. van Poollen, performed work on an electrolytic model to determine the effect fracture lengths and flow capacity would have on the production increase obtained from wells with different drainage radii. Several others developed mathematical models for similar projections. Today, there are models that predict production from fractures with multiphase and non-Darcy flow using any proppant available.

Fracturing's Historic Success

Many fields would not exist today without hydraulic fracturing. In the US, these include the Sprayberry trend in west Texas; Pine Island field, Louisiana; Anadarko basin; Morrow wells, northwestern Oklahoma; the entire San Juan basin, New Mexico; the Denver Julesburg basin, Colorado; the east Texas and north Louisiana trend, Cotton Valley; the tight gas sands of south Texas and western Colorado; the overthrust belt of western Wyoming; and many producing areas in the northeastern US.

As the global balance of supply and demand forces the hydrocarbon industry toward more unconventional resources including US shales such as the Barnett, Haynesville, Bossier, and Marcellus gas plays, hydraulic fracturing will continue to play a substantive role in unlocking otherwise unobtainable reserves. JPT

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HYDRAULIC FRACTURING

THE FUSS, THE FACTS, THE FUTURE

Robin Beckwith, *JPT/JPT Online* Staff Writer

While precise statistics on the hydraulic fracturing industry are not kept, there is little doubt its use has grown precipitously over the past decade. Despite low gas prices, North American fracturing activity is at an all-time high, with competition between fracturing companies fierce, margins slim, and volumes huge. With an estimated 4 million hhp of equipment being built in the US, there are waiting lists for services and supplies, and delays of up to 9 months are common. China and India are investigating the potential of unconventional-gas resources that demand the use of hydraulic fracturing to produce at commercial flow rates, and also are stepping up investment in North American and Australian shale acreage. European countries like Hungary, Poland, Germany, and France–keen on easing dependence on Russian energy–are also looking to exploit their tight resources.

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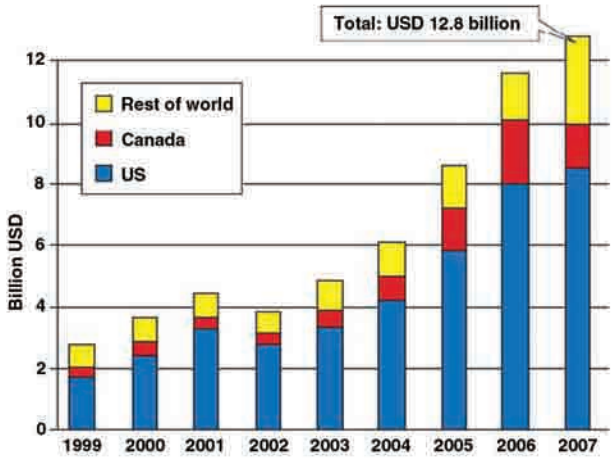

Fig. 1—Estimated size of the global fracturing market since 1999. Courtesy: Michael Economides, *Energy Tribune*.

Fig. 2—Equipped with 8,250 hhp and 15,000 psi-capable pumps and manifolds, Halliburton's *Stim Star Angola* delivers a wide range of stimulation services offshore West Africa. Photo courtesy: Halliburton.

But it is not all about shale. With 2007 estimated service-company hydraulic fracturing revenues representing a global market of USD 13 billion **(Fig. 1),** up from approximately USD 2.8 billion in 1999, the technique is now more than ever a vital practice enabling continued economic exploitation of hydrocarbons throughout the world–from high-permeability oil fields in Alaska, the North Sea, and Russia, to unconsolidated formations in the Gulf of Mexico, Santos Basin, and offshore West Africa **(Fig. 2),** to unconventional resources such as shale and coalbed methane (CBM) developments **(Fig. 3).**

What Is Driving the Rise in Hydraulic Fracturing?

It is not surprising to find that North America is home to an estimated 85% of the total number of hydraulic fracturing spreads **(Fig. 4)** (according to Michael Economides, a spread is the equivalent of four fracturing units, a blender, and ancillary equipment)–including land **(Fig. 5)** and offshore equipment**.** This stems from its mature, reliable infrastructure, fueled by the dependence of a population long used to creating demand. The phenomenal increase in US proved reserves of natural gas–from a 20-year low in 1994 of 162.42 Tcf to its 2009 estimated 244.66 Tcf–is the direct result of advances in hydraulic fracturing and horizontal drilling. The scramble for this resource, however, giving rise to what an IHS CERA report calls the "shale gale," is the result in North America to avert what was predicted earlier in the century to be the need to import vast quantities of natural gas in the form of liquefied natural gas (LNG) from farflung locations. Although shale and CBM are also widely prevalent outside the US, the need in most countries–with the possible exception of the European Economic Union–to turn to them, remains less urgent, as conventional resources remain far from depleted. Indeed, the top three countries in terms of estimated proved natural-gas reserves–Russia, Iran, and Qatar–held a combined total 14.5 times that in the US, at 3,563.55 Tcf year-end 2009, 57% of the world's 2009 total estimated proved reserves of 6,261.29 Tcf. So, while hydraulic fracturing and natural gas–and to a certain extent oil–extraction have been linked in the recent focus on unconventional shale resources within the US, the long-term future lies well outside that country.

Currently within North America, 10 or more fracture-treatment stages are performed to stimulate production along a horizontal

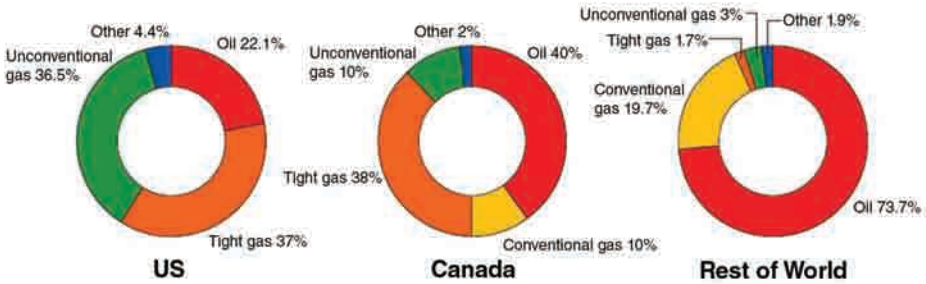

Fig. 3—Estimate of approximate breakdown of fracture treatments by well type. Courtesy: Michael Economides, *Energy Tribune*.

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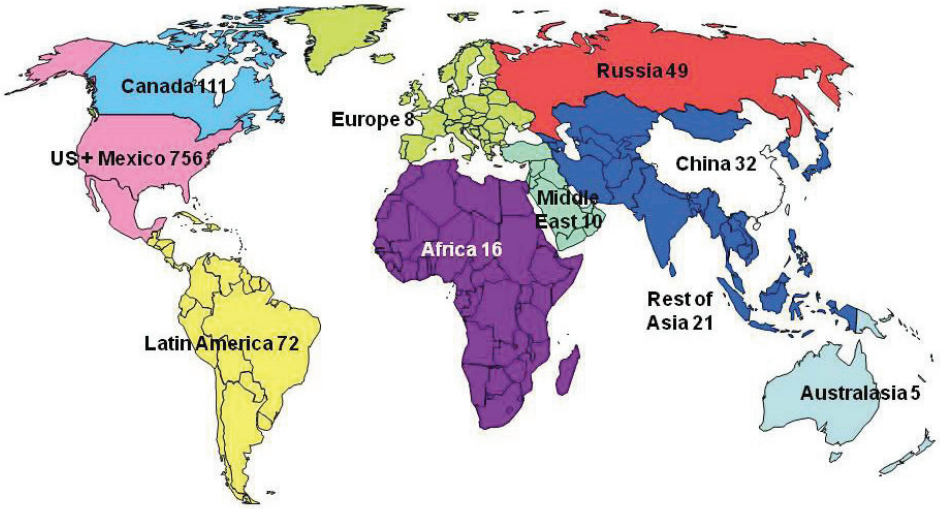

Fig. 4—Estimated global distribution of fracturing equipment, including land fracturing spreads and offshore vessels.

borehole, while typically outside North America, the number of fracture-treatment stages per well is rarely more than two or three. Low natural-gas prices and lack of infrastructure are two key drivers for this phenomenon. Outside North America, service companies have yet to establish–or benefit from–sufficient infrastructure or gain enough experience to deliver consistent results.

Costs that service companies must deal with per well tend to be three to four times higher outside North America due to such factors as fragile distribution channels or poorly performing equipment and personnel. The result is that service companies must charge higher prices to remain economically viable, which in turn makes it highly unattractive for operators to permit learning, through practice and analysis, about the formation and about how to run the fleet and crew. However, a practical way to combat this, according to BP Exploration senior petroleum engineer and adviser Martin Rylance, is to deeply focus on the operational quality assurance/quality control and execution on the pilot fracture treatments, and simply overdesign these treatments with more length and conductivity than strictly necessary. Optimization of the fracture treatments can be an evolving story as more treatments are performed. The absolute key, said Rylance, is to first establish effective, competent, and successful fracturing and economical results.

Fig. 5—Hydraulic fracturing treatment, Woodford Shale, Canadian County, Oklahoma, for which Halliburton provided 52,000 hhp.

The development and application of hydraulic fracturing technology in the US has been driven by independents, with a low cost base and the critical mass necessary to learn and respond quickly to new developments in modeling, planning, fluids, and proppants technology. With plays containing dozens of operators, each seeking technical and economic advantage over the other, the pace of technological development in the US has been fast–propelled in part by regulatory requirements in most areas throughout North America to reveal fracturing and production-performance data within 6 months following execution, which competitors can then plunder for insight. The US also benefited from a tax incentive created in the 1980s, which, along with high gas prices, jump-started US tight gas exploitation. By 1992, when the incentive ended, the resulting infrastructure, critical mass, and expertise were in place to continue economically without incentives.

Driven by increasing demand for power generation, countries like China and India are eager to cost-effectively develop their own resources, as well as participate in the boom that has struck US shale. In August, both nations signed agreements with the US State Department allowing the US Geological Survey to evaluate data on potential shale plays within those countries to determine if the formations possess recoverable gas.

They are also grabbing up resources within the US. For example, India's largest company, Reliance Industries, led by billionaire Mukesh Ambani, has purchased shares in US shales worth USD 3.4 billion so far this year. Ambani appears to be pursuing a learn-as-you-earn strategy. Evidence for this can be found in the nature of the joint venture into which Reliance entered with Carrigo Oil & Gas on Marcellus Shale acreage in central and northeast Pennsylvania in early August. Reliance holds a 60% interest and Carrigo is the operator, but Reliance has the option to act as operator in certain regions in the coming years. Ambani expects to build on what his company learns about techniques like fracturing while profiting as approximately 1,000 wells are drilled over the next 10 years within a net resource potential of about 3.4 Tcfe (2.0 Tcfe to Reliance).

Smaller countries, like France and Norway, are pursuing similar

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Fig. 6—Proppant being moved into the hopper for feeding into blender trucks from which the mixture will be pumped downhole during hydraulic fracturing. Location: Haynesville well in northern Louisiana. Photo courtesy: Carbo Ceramics.

strategies–linked to hydraulic fracturing as an enabling technology. Total, for example, announced its first investment in a coal-seam gas project, paying around USD 750 million for a 20% stake in an Australian joint venture. The project will convert coal-seam gas from fields in Queensland into LNG at a plant on the country's east coast, from where it will be sold to energy-hungry Asian markets. Total is also buying a 15% stake in the Gladstone LNG project from Australia's Santos, and a 5% stake from Malaysia's Petronas. The French group said it will also explore opportunities to cooperate over other Santos gas assets in Australia.

Earlier this year, Statoil added to its US Marcellus Shale position by acquiring nearly 59,000 net acres from Chesapeake Energy. Statoil entered the Marcellus shale play in late 2008 when it first acquired acreage from Chesapeake, and aims to have shale production of 50,000 BOEPD from these assets by 2012. The company intends to build infrastructure and confidence through its Chesapeake joint venture to become an operator of unconventional-gas assets.

Another strategy is to invite experienced foreign companies to share in exploiting home-front shales. For example, China's largest listed gas producer, Petrochina, and Royal Dutch Shell have partnered to develop shale-gas resources in China's Sichuan province. PetroChina, however, is hedging its bets: It also has planned USD 60 billion in overseas investments to boost its oil and gas output, following the example of other companies like China Petroleum & Chemical Corporation and CNOOC.

Keeping the Fracture Open: Proppants

With the rapid rise in hydraulic fracturing over the past decade, the number of proppant suppliers worldwide has increased from a handful to more than 30 sand producers, nine resin coaters, and at least 10 ceramic manufacturers.

According to a 2009 global proppant market study by D. Anschutz and B. Olmen, published by PropTester and Kelrik in early 2010, proppant consumption was a low-growth market through the 1990s, but rose from an estimated 3 billion pounds in 1999 to total consumption of nearly 20 billion pounds in 2009 **(Fig. 6).**

Proppant grain size has become finer as the use of slickwater fracturing has increased, with 20/40 the dominant gradation throughout the 1990s and early 2000s. However, according to Kelrik owner Olmen, "Slickwater fracturing of unconventional-gas resources represents nothing short of a paradigm shift in its impact on proppant volumes, types, and sizes." The result is that today the use of 30/50 and 40/70 sand and resin-coated sand, 40/80 ceramics, and 100-mesh sands of various gradations is common.

It is interesting to note, however, that the use of proppants 16/20 or larger in fractures performed in West Siberia, for example, has increased from 43% of the jobs in 2003 to more than 90% of the jobs today–indicative of trends elsewhere that buck those occurring in North America.

North America remains the dominant manufacturer of proppant **(Fig. 7).** The first non-US plant designed to produce fracture sand meeting *API RP 56* recommendations was built in 1985 by Colorado Silica Sand near Chelford, England. A select few small natural-sand and resin coating operations followed in countries such as England, Denmark, Poland, and Saudi Arabia. But, according to Olmen, the real development outside North America has been in the production of high-strength ceramics and sintered bauxite. Brazil, Russia, and China, for example, have established substantial synthetic-proppant manufacturing capacities, all of which export to North America.

The Vital Need for Fluids

Vast shales are the deposits of oceans that existed in the Paleozoic and Mesozoic eras and as such present resources whose steady exploitation will last many decades–even centuries. Plenty of these shales were in fact the known source rocks for many already widely developed oil and gas formations. Now these source rocks are themselves turning out to be excellent reservoirs.

However, outside North America, such resources represent a far longer-term frontier, with most hydraulic fractures still performed on conventional formations, which often respond best to complex cross-linked fluid technology. Because the unconventional-gas formations now primarily targeted in North America require high-rate water fracturing and slickwater technology, Rylance

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Fig. 7—Fracturing sand being transported into the Marcellus shale region. Photo courtesy: D&I LLC/Prop'N Rail, Sheffield, Pennsylvania.

voiced a concern that "We are creating a whole generation of fracturing personnel in North America who have never heard of and do not understand the complexities and intricacies of cross-linked gel fracturing, equipment operation, pumping, design, and execution."

IPointOil President Hemanta Mukherjee is passionate about the need for "green" fluids. "Use of hydraulic fracturing will only grow," he stated. "This means it will be much more widely used in environmentally sensitive areas like deep offshore and arctic tundra." Green additives are being developed and used. One of these is tetrakis-hydroxymethylphosphonium sulfate or THPS biocides, a class of antimicrobial chemicals with low overall toxicity and rapid breakdown in the environment, which won a US Environmental Protection Agency award in 1997 and is used as a means of protecting the gelling agent guar from degradation as well as combatting corrosion effects over the life of the well.

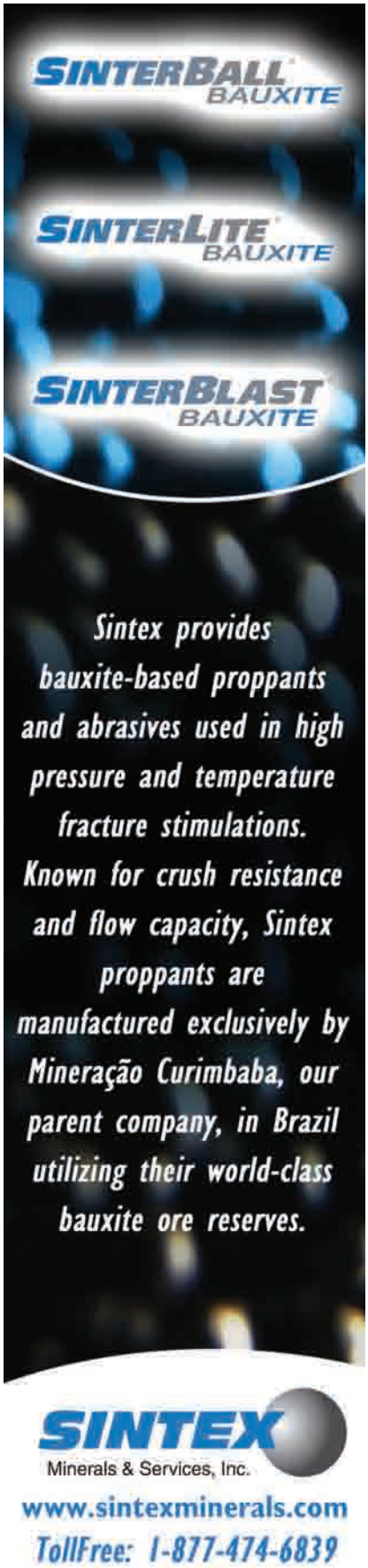
Flowback water is a bigger concern. A promising solution to this is fracture-fluid recycling. An example, delineated by D.V.S. Gupta and B.T. Hlideck of BJ Services (paper SPE 119478), involved shallow-gas fracturing in western Canada, where typically several thousand wells are drilled and completed every year, all of which are hydraulically fractured. Driven by scarcity of water and the high cost of surfactant-gel frac-flowback-water disposal, project operators sought means of rationalizing resources. On a project basis, it was found that 50% of the load water recovered could be recycled, resulting in a nearly equal reduction on trucking and disposal costs. Significant savings could also be made in chemical-addititve costs.

Stephen Holditch, professor and head of the Harold Vance Department of Petroleum Engineering at Texas A&M University, stated, "In the future, the industry needs to look at developing polymer-free fluids or fluids with polymers that degrade more completely at temperatures below 250°F." A key to accomplishing this, he said, is the development of "better fracture-fluid mathematical models to simulate filtrate invasion and cleanup in tight gas sands."

The Key to Fracture Success: Fracture Design

According to Simon Chipperfield, team leader Central Gas Team at Santos, the key challenges facing hydraulic fracturing remain understanding the interaction between created fractures and the reservoir. He stated that good progress has been made in the development of processes like after-closure analysis to define reservoir properties and microseismic to define fracture extent. Additional independent sources of information taken over the life of the well, he said, are required to improve understanding of, for example, the performance of individual fracturing stages in wells where many stimulation treatments are placed.

The University of Calgary's Antonin Settari concurred. "The industry still does not completely understand the geomechanical effects of unconventional well fracturing," he said. Although each shale play presents its own set of challenges that render it



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Hydraulic Fracturing Seeps into Public Awareness

The US Environmental Protection Agency is currently designing a study examining the possible relationship between hydraulic fracturing and drinking water (http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/, www.nytimes.com/2010/09/10/business/energy-environment/10hydraulic.html?_r=1).

The US House of Representatives Committee on Energy and Commerce continues to examine the potential environmental impact of hydraulic fracturing (www.energycommerce.house.gov/documents/20100719/Memo.Hydraulic.Fracturing.07.19.2010.pdf, www.energycommerce.house.gov/documents/20100719/Letters.Hydraulic.Fracturing.07.19.2010.pdf).

In mid-September, Wyoming became the first state in the US to require public disclosure of all chemicals used in fracturing. The actual formula for the fluid can remain a commercial secret, but the ingredients must be revealed to the state.

While they investigate the possible link between hydraulic fracturing and aquifer contamination, New York state regulators have placed a moratorium on new gas drilling, and the state Senate voted in August to prohibit new permits until 15 May, 2011.

Four documentary films on hydraulic fracturing–two pro and two con–have emerged this year: *Gasland* (www.gaslandthemovie.com), *Haynesville* (www.haynesvillemovie.com), *Split Estate* (www.splitestate.com), and *Gas Odyssey* (www.gasodyssey.com).

Stories on fracturing have appeared in numerous mainstream venues, including magazines (www.vanityfair.com/business/features/2010/06/fracking-in-pennsylvania-201006), CNN (www.cnn.com/2010/US/09/13/fracking.explainer/index.html?iref=24hours, www.cnn.com/2010/US/09/02/fracking/index.html), Popular Science (www.popsci.com/technology/article/2010-09/instant-expert-unnatural-gas), and smaller news publications and blogs.

economically necessary nowadays for operators to learn from empirical experience, Settari estimates that research being conducted today by various consortia–including the one the University of Calgary has launched, along with Anadarko, BP, Shell, Statoil, and Eni–will trickle down into predictive software within the next 3 to 5 years.

As Rylance stated, "Hydraulic fracturing is a very forgiving technology," with the ability to achieve good results in a commodity-like manner within North America, where its use is, by and large, based on models developed 25 to 35 years ago. "However, if you do it right, the results can be game-changing, with skilled and effective fracture deployment often being the difference between an economic and uneconomic development overseas."

To achieve better outcomes, not only is the development of predictive models necessary, but so is data sharing and integration. "Companies do not easily share," Rylance continued. "Service companies' ability to design and execute optimum fracture treatments is hampered because they can't see the whole picture. There are four things service companies need to design optimum fractures: reservoir permeabilities, the in-situ stress distribution, a sound geologic model, and fluid-loss characteristics in naturally fractured formations." An aid in this area would be Halliburton's recently released DecisionSpace Desktop software, one of whose purposes is to further better integration of real-time, fracturing-related data from the field with the shared Earth model built by the asset team.

Environmental Impact

In remarks to the 2010 World Energy Congress, Daniel Yergin, chairman of the consultancy IHS CERA, pointed to shale-gas development as the single most significant energy innovation so far this century. Without hydraulic fracturing, coupled with advances in horizontal

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drilling, this phenomenon would be physically impossible. It is less cumbersome and more economically and politically advantageous for countries to rely on supplies of natural gas that are close to the market in which they will be used–a key advantage, along with methane's much-touted "clean-burning" reputation, that makes shale so attractive. Indeed, Holditch stated that "for the next few decades, the best hope for increasing the clean energy supply is to promote the use of natural gas."

However, with shale exploitation nudging ever closer to areas of human habitation and aquifers within the US, public awareness of the oil and gas industry's presence and practices is growing, accompanied at times by fears and questions. The rest of the world stands to learn from US public and governmental response, studies, and media reaction to a suggested link between hydraulic fracturing and groundwater contamination. According to NSI Technologies President Michael Smith most of this concern is unfounded as fracturing is typically conducted thousands of feet below aquifers and the chemicals in the fluids are mostly fairly benign. The chances of creating a flow path for natural gas to the surface are diminishingly small. Well-construction problems and gas seepage from poor well completions close to the surface would be more likely culprits. He did note, though, that if the well penetrates a large natural fault there is some risk, when pumping huge-volume water fractures, that water can be injected at high pressure directly into the fault, causing a minor earthquake.

The Future

While the human population growth rate is declining, our presence on this planet, currently estimated at 6.88 billion, continues to climb as does our reliance on consistent supplies of oil and gas. Yergin predicts that world energy demand will increase 32–40% over the next 20 years. "Much of the infrastructure that will be needed in 2030 to meet the energy needs of a growing world economy is still to be built," he said. Building that infrastructure in and of itself will aid economic growth. And hydraulic fracturing will continue to be used throughout the world in a wide range of formations including shale as a technology that plays a vital role in releasing the hydrocarbons human societies rely upon for peaceful economic continuance. JPT

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