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Horn River Playbook

From the editors of

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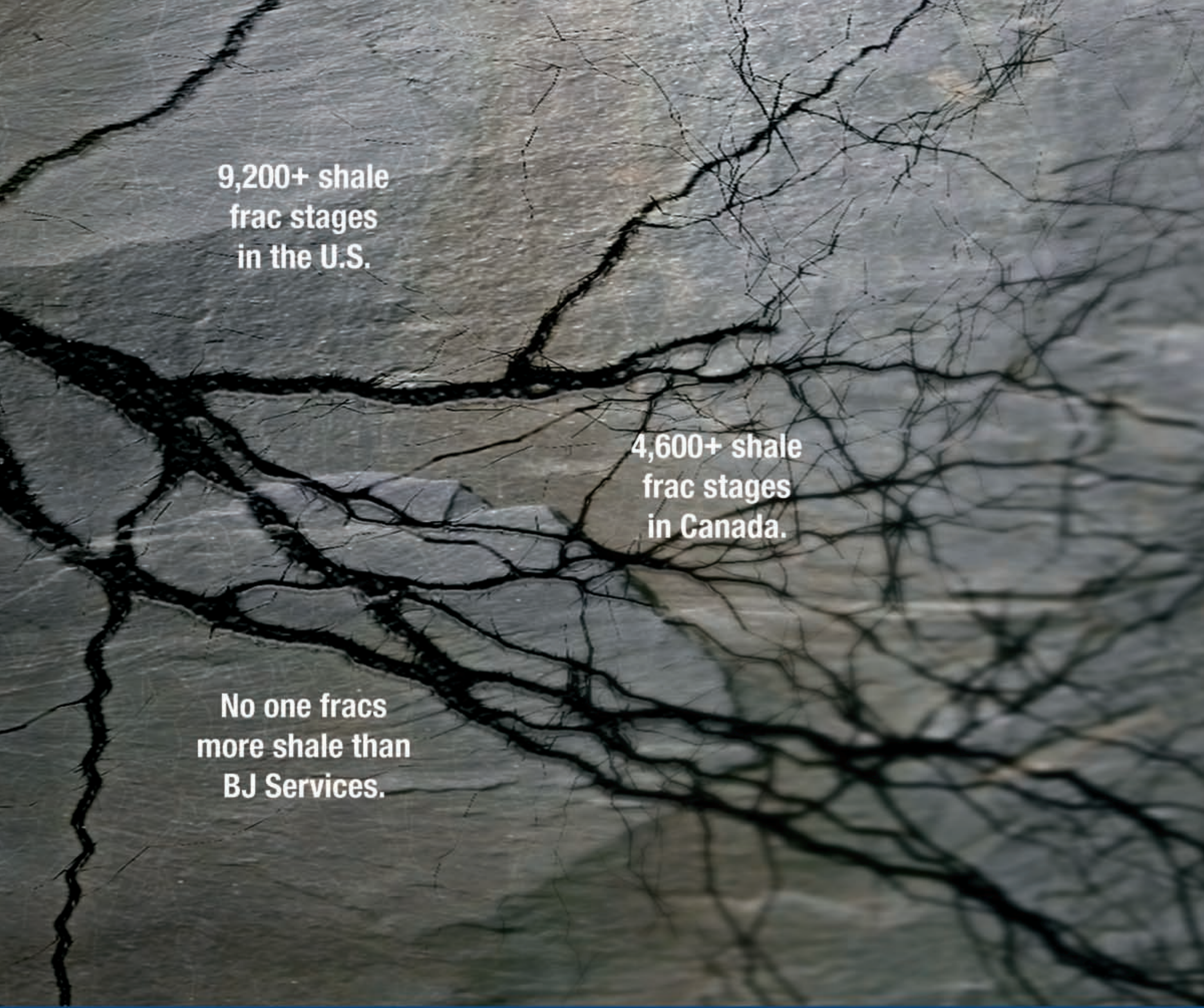
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Horn River: *The Playbook*

From the editors *Oil and Gas Investor, E&P,* and *Pipeline and Gas Technology*

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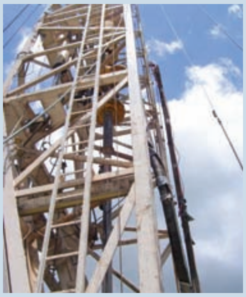

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Right, Precision Drilling Rig #638 drills a Horn River Shale well for Devon Energy Corp. on its Komie Block, north of Fort Nelson, British Columbia.

Photos courtesy of Lowell Georgia

Horn River Shales

British Columbia's faraway Horn River Basin will one day be among the elite North American gas-producing provinces, thanks to its treasure of rich, black shales.

By Peggy Williams
Senior Exploration Editor, *Oil and Gas Investor*

It's not easy to get to Canada's Horn River Basin. From the Lower 48, the first stop is Calgary. Next, an 800-mile (1,287-km) car ride or chartered two-hour plane flight brings a traveler to Fort Nelson, British Columbia.

Fort Nelson is Mile 283 on the Alaska Highway, and the legendary road serves as the community's main street. In its early days, the town was an outpost of North West Co., and more than 200 years later fur trappers continue to ply that trade. Today, the timber and oil and gas industries employ residents as well.

From the town, Horn River Basin shale-gas activity lies deep in muskeg, another two to three hours away.

This is tough and brutal country. Winters are pitiless, and temperatures skid to 40 degrees below zero (at that mark, Celsius and Fahrenheit scales converge). Unless an all-weather road has been built, muskeg is only passable when frozen. Otherwise, the area is an impossible bog.

Yet, its shale gas potential could turn this isolated corner of Canada into one of the continent's top gas fields. The Horn River Basin covers some 3.2 million acres, stretching from just north of Fort Nelson to the BC/Northwest Territories border. The heart of the emerging shale play is thought to cover at least a million of those acres.

In-place gas volumes are stunning: the Canadian Society for Unconventional Gas estimates that as much as 500 Tcf of gas lies in place below the Horn River's muskeg.

If a standard shale-gas assumption of 20% recovery is applied, the Horn River could hold up to 100 Tcf of recoverable reserves. Considered as a single field, that would place the Horn River in the rarified ranks of the top natural gas accumulations on the planet. And this is brand-new, never-before-seen gas.

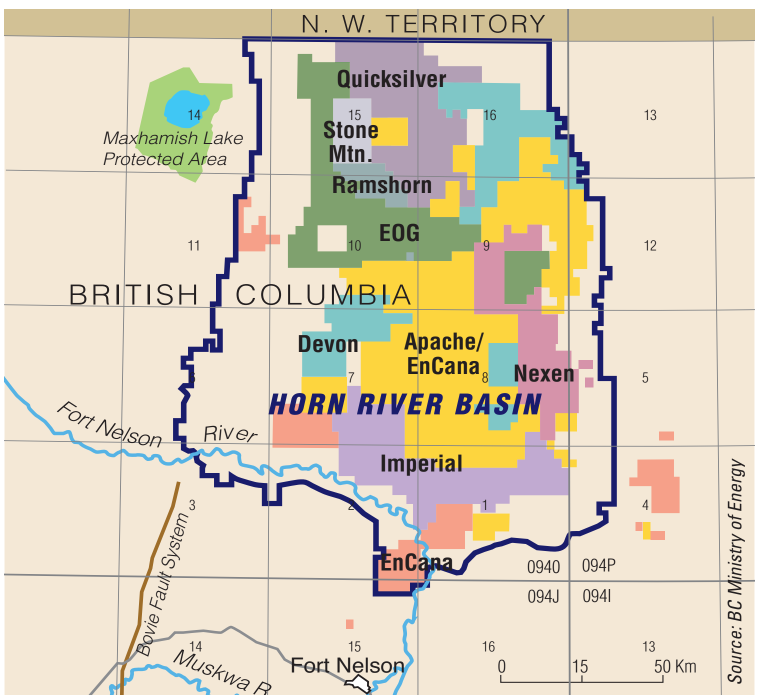
This article is adapted from the May 2009 *Oil and Gas Investor* article "Horn River Shales."

Auspicious geology

The Horn River Shale play is cradled between two historic areas of oil and gas production. Along the basin's eastern edge, the Slave Point carbonate platform initially produced from prolific reefal buildups; later, a horizontal drilling play in the overlying tight Jean Marie carbonate developed. A web of infrastructure from these activities laces across the platform.

On its western side, a dramatic fault system separates the Horn River from the Liard Basin. Production

Most acreage in the center of the basin is already held by companies.



west of the Bovie Fault developed in Cretaceous sandstones at sprawling Maxhamish Field. This accumulation also spawned gas-collection and transportation facilities.

But within the basin itself, exploration was limited and without success. Since the 1960s, a few hundred wells were drilled in the Horn River Basin's interior to no avail. Porous reservoir rocks were completely lacking, and production was never realized.

Nonetheless, it was well known that the quiet interior basin had accumulated tremendously thick, extremely fine-grained sediments. "These shales are locally quartz-rich, and not dominated by clay minerals, even though they are very fine-grained rocks," said Vic Levson, Victoria-based executive director, resource development and geoscience branch, British Columbia Ministry of Energy, Mines, and Petroleum Resources.

As the industry became comfortable with shale gas development, several firms realized that shale in the Horn River might offer an attractive target.

Too, the province had been promoting the Horn River shales for some time. "We saw the shales developing in the States and we knew we had some pretty good shale packages in BC," said Levson. In 2004, the ministry released a comprehensive report on Devonian shales in Northeast BC. "We compiled all existing information on the shales, most of which was taken from wells in the Slave Point reef play."

Horn River shales are Upper to Middle Devonian in age, and their stratigraphy is unclear. There's debate about whether the Horn River shales are all one formation, or if they should be divided into additional units.

Industry generally separates the shale into the uppermost Muskwa and Otter Park package and the underlying Klua and Evie shales, isolated from each other by a tight, thick carbonate zone. Regardless of lumping or splitting, total shale thickness reaches about 600 ft (183 m).

The shales vary internally and across the basin, thickening in various areas. "The upper shales — Muskwa and Otter Park — appear to be more prospective in some areas, and the Klua/Evie in others," Levson said.

A land rush started in the Horn River Basin in 2006, when operators spent CAD $126 million on licenses in government sales. The next year, the province pulled in CAD $359 million for leases in the sparsely drilled basin. Sales in 2008 totaled an astonishing CAD $1.1 billion.

"Most of the center of the basin is now held by companies. There is still some open ground around on the margins, but virtually all the core area has been sold."

The entire basin appears prospective for shale-gas production, said Levson, although there's still a great deal to learn. Happily, lots of new data are coming available. British Columbia has a program of experimental schemes that allows operators to hold well data confidential for three years, and a number of these were issued in the Horn River during the past four to five years. As confidentiality periods wind down, more information will become available.

And what is coming out buttresses the high opinions already held about this striking new shale play.

Discovery to dominance

Calgary-based EnCana Corp. is widely credited with discovery of the Horn River Shale play in 2003. The company encountered strong gas kicks in the shales while drilling a Middle Devonian carbonate test. EnCana was familiar with the region, as it was actively developing its Greater Sierra play in the Jean Marie carbonates to the east, said Mike Graham, executive vice president and president, Canadian Foothills division.

"It took us a little while to figure out the Horn River shales, but we eventually did," said Graham. "We had a lot of help from our US business units, because we weren't used to the shales up here at the time."

The company drilled a handful of vertical wells, took core, and completed and flow-tested the shales. "We were figuring out the shale's attributes," Graham said.

EnCana began to accumulate acreage. In British Columbia, companies make requests to the provincial government to post available Crown lands, and these lands are sold at public auctions. After EnCana launched its land program, other companies began to notice.

Apache Canada was also active at the sales, so the two firms decided to join forces going forward. EnCana's position currently stands at 250,000 net acres. Most of its acreage is held jointly, but each firm still owns some tracts of 100% land.

Horizontal drilling kicked off two years ago.

In 2008, the EnCana/Apache joint venture drilled seven Horn River wells; the most recent completion flowed gas at an average rate of just under 8 million cf/d during its first 30 days of production.

"We've had wells online now for over a year, and we're impressed with the decline rates. They are leveling out," said Graham. "Obviously, time will tell. It's still early."

Certainly, the Horn shales look very good. They are wonderfully thick, from 150 ft to 350 ft (46 m to 107 m) per discrete interval; overpressured, in the range of 0.65 psi per foot; thermally mature; and they hold tremendous gas in place. "We think these shales have as much as 150 to 250 Bcf per section." Furthermore, the mineralogy makes the shales amenable to fracturing treatments.

at the end of the continent's gas infrastructure, and the discount to Henry Hub is stiff. Processing is also required, as EnCana's Horn gas contains close to 12% CO_2 and trace amounts of H_2S — just enough to be a real nuisance.

"However, we do have some real pluses going for us," said Graham. "Our dollar has weakened quite a bit, which is good for producers. And the royalty system is very attractive in British Columbia. The government has done a tremendous job in incenting the industry."

Within a handful of years, EnCana thinks it can pull the Horn River into the top half of its portfolio, and have supply costs sub-US $5/Mcf. "We've positioned our portfolio to have very low supply costs, and we think we'll be one of the last producers standing even in a low-price environment."

THE SHALES VARY INTERNALLY and across the basin, thickening in various areas. "The upper shales — Muskwa and Otter Park — appear to be more prospective in some areas, and the Klua/Evie in others."

—**Vic Levson,** *BC Ministry of Energy, Mines, and Petroleum Resources*

"The Horn shales are similar to Barnett Shale and have more gas in place," said Graham.

EnCana's drill-and-complete well costs are currently north of CAD $10 million. Once it gets its gas factory going, it expects costs to drop considerably. Initially, the company ran its laterals to 3,300 ft (1,006 m). Now, it drills 5,000- to 5,500-ft (1,524-m to 1,676-m) laterals. At present, the operator finds it's actually cheaper to drill its wells than to frac them.

And, it's doing more and bigger fracs. "Now we're at a million gallons a stage, and as many as 14 stages per well," said Graham. Stages are spaced some 400 ft (122 m) apart, resulting in about eight-acre spacing per frac. "It's similar to what's being done in other shale plays—closer spacing really drives up recovery factors."

EnCana measures its costs on a per-frac basis. It wants to bring costs on the Horn River fracs down to about CAD $750,000 each. It expects recoveries to range between 0.5 and 1 Bcf per frac.

Naturally, current commodity prices present daunting economics. The Horn River Basin lies nearly

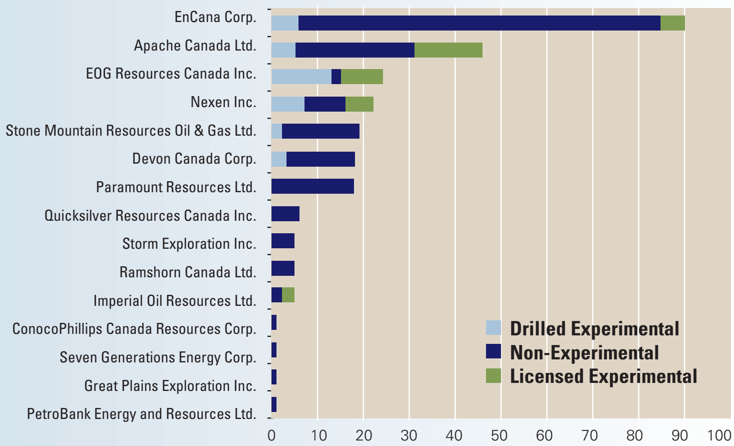
For 2009, EnCana and Apache plan 24 horizontal wells in the Horn River, mainly into the Muskwa and Otter Park. Initially, the partners budgeted about 40 wells, so the well count has dropped. However, the two dozen tests will feature longer laterals and more fracs, so the number of fracs has actually held steady.

"In the heart of the play, we think we can consistently drill wells that are capable of flowing 10 million cubic feet per day during the first 30 days," said Graham. "We have the thickest, cleanest shales in the unstructured part of the basin, and we think they'll be very economic."

Currently, the company has approximately 6 million a day of net production from its interests in seven producing horizontal wells. EnCana is completing four wells on a pad in the Two Island Lake area, and will tie these into production shortly. By year-end, if all goes as well as planned, it could be producing close to 100 million gross a day.

"We think we could eventually produce 1 Bcf equivalent a day, net to EnCana, from the Horn River,"

Key Operator Activity (since 2001)



Source: BC Ministry of Energy, Mines and Petroleum Resources, Oil and Gas Division, Geoscience Branch

In the Horn River Basin, operators drill two types of wells: experimental schemes, which allow for three-year confidentiality periods, and non-experimental wells.

said Graham. "We see 200 to 300 Tcf of original gas in place in the basin; as in the Barnett, recoveries could go as high as 50% in places.

"In a few more years, this could become one of our key resource plays," Graham said.

Lowering costs, raising rates

EnCana's Horn River partner Apache Corp. was early to the play. The joint venture holds some 450,000 acres; half of that is net to Houston-based Apache.

"This play looks real. The numbers we are seeing are very encouraging, and our focus now is on reducing the unit cost of production," said John Crum, Apache co-chief operating officer and president, North America.

"We believe we have gas on all our acreage, but we are concentrating our efforts in a fairly small area because we can build production volumes more quickly."

The companies have zeroed in on the Two Island Lake area, in 94-O-8 and 94-O-9. As in many shale plays, the acid test for the Horn River is well performance on tight spacing. Drilling at Two Island Lake will investigate drainage area. The JV partners will continue to experiment with increasing both the length of laterals and number of frac stages in each lateral. At present, it appears that each additional frac stage adds to rate and recoverable reserves, but there will be a limit.

Apache is also intrigued with the lower Klua Shale. The lower shale can be 150 ft (46 m) thick at Two Island Lake, about half of the 320 ft (98 m) attained by the upper shales. Rock evaluation data are strong, however, and the partners completed a Klua well in their 2008 program. It was fractured in four stages, and after six months is still producing about 1 MMcf/d.

"Results have been encouraging," said Crum.

This year, Apache will drill 14 horizontal wells off a single pad into the upper Otter Park Shale, and two wells into the Klua level. That pair will run immediately next to each other, to evaluate well performance on close spacing.

In a perfect world, Apache would prefer to drill out each pad with 28 wells, split evenly between the upper and lower shale packages. "But we'll have a limited number of rigs working, so we'll go after the biggest target first, which is the Otter Park," Crum said. It will save the lower shale for later.

"We can't do anything about gas prices, so we're working on lowering costs and getting higher volumes for the same costs," said Crum. Pad drilling adds efficiencies, from well supervision to coordination of frac jobs.

One of the play's challenges is its remote location. If the play goes as hoped, Apache wants to be able to ramp up volumes quickly. In that light, Apache and EnCana are rapidly adding infrastructure, putting in dehydration facilities and building a compressor station. A 24-in., 40-mile (64-km) pipeline will be ready this spring to carry gas from Two Island Lake to Spectra Energy Corp.'s pipeline system at the Cabin Lake compressor station.

The Horn River is a far piece from markets, and Apache figures its gas will likely sell at a discount to Nymex, basing its economics on a discount of about $2.38/Mcf, including processing and pipeline tariffs. "The location affects both the price of doing things and the market on the other end," said Crum.

"We still have a lot of hurdles to cross with this play." Associated with any big gas development are environmental issues, and aboriginal and local effects have to be considered.

A road stretches to the horizon from one of Devon's drilling pads in the Horn River Basin.

"But a great feature of the Horn River is it's a blank slate. We have a chance here to get considerable volumes of gas out of the ground with minimal impact on the environment, and at the same time provide a lot of jobs for the Fort Nelson community. It can be a win-win for everyone."

Rivaling the Barnett

Oklahoma City-based Devon Energy Corp. was interested in the Horn River play early on, intrigued by its parallels to its marquee Barnett shale assets in North Texas. It initially looked at BC's Devonian Shale potential in 2006 when it recompleted a Muskwa shale interval in a suspended well in Wildmint Field, 60 miles (97 km) northeast of Fort St. John. Positive test results spurred interest in acquiring a land position in the Horn River Basin, where the shale is thickest.

Devon attended its first sale of Horn River Crown land in 2006, and rights went for CAD $800 to CAD $1,500 per hectare (one hectare equals 2.47 acres). "Land was never cheap; a company had to believe in the play without much information," said Brent Snyder, Horn River exploration manager, Devon Canada.

In the 2006-07 winter season, Devon drilled and cored a stratigraphic test on its central block. That well intersected 500 ft (152 m) of shale and flowed gas after completion.

"Results were good, which raised our confidence in the play," said Gerry de Leeuw, Devon Canada vice president of exploration.

Indeed, the Horn River shales compared quite favorably with the Barnett Shale, a play mastered by Devon in the US. Although both occur at depths between 6,500 ft to 8,500 ft (1,981 m to 2,591 m), the Horn River shales are thicker, hotter, more highly pressured, more siliceous and contain more gas-in-place per section. Devon estimates the Horn River shales hold between 200 and 300 Bcf of raw resources per section, compared with the Barnett's 75 to 200 Bcf.

The company jumped into the leasing fray that rocked BC in 2007 and 2008. After the dust settled, Devon had acquired 153,000 acres of drilling licenses in the Horn River, in several chunks of land in the central, western and northern reaches of the play.

"Each block is large enough to be developed as a stand-alone project," said Snyder. Government leases have two phases: an operator has five years to validate a license with a well and, after validation, licenses are

Pipeline construction seemingly extends to infinity across the frozen muskeg. Sections are weighted to keep the line buried when summer temperatures thaw the muskeg.

held for an additional nine years. Companies can validate a number of sections with each well, so the pressure to hold leases is light when compared with the situation in the U.S. Devon, for instance, needs to drill just 20 additional wells to validate its entire position.

In Devon's central Komie area, depth to the base of the 650-ft (198 m) gross shale section is 8,700 ft (2,651 m). On its western block, wells need to reach 9,200 ft (2,804 m) to penetrate the entire shale section.

To date, Devon has concentrated its work on its Komie Block, a bit south of EnCana and Apache's Two Island Lake area. In 2008, Devon drilled a stratigraphic test and two horizontal tests. This year, it has drilled three horizontal wells and is shooting 3-D seismic across its block.

"We have approximately 500 ft (153 m) of high-grade shale, in the Muskwa, Otter Park and Evie zones," said Snyder. "We're still trying to define net pay, as we are in the early stages of play development." The high-resistivity shales are overpressured, competent, and have porosities around 5%. Some swelling clays are present in overlying shale and carbonate strata, so Devon drills its wells with oil-based muds.

To date, it has drilled laterals varying from 2,500 ft to 4,600 ft (762 m to 1,402 m) in length, and fractured them in multiple stages. Two wells with 2,500-ft (762-m) laterals were treated with four stages each. "Per frac stage, we're seeing similar results on our wells to what other operators have reported," said de Leeuw.

"Our challenges right now are drilling and getting the completions designed just the way we want. It's a classic resource play. Now that we, and others, have tested the play, there's very little risk on the geology," he said. "It's mostly commercial risk: how do we get the wells drilled and at what cost?"

Devon's initial pilot wells run CAD $12 million each; that cost should drop to some CAD $8.5 million when it shifts to full-scale pad developments. The pads allow numerous efficiencies, particularly in logistics and personnel use. The company is also investigating potential of the Mississippian Debolt as a water-source and -disposal zone on its block, another cost-saving measure.

Currently Devon produces 3 million a day from the Horn River play. "We see potential for 300 million a day in raw gas production from our Komie Block alone," said de Leeuw. "Across our entire position, we think we have potential for raw gas recovery of up to 1.2 Tcf and net potential production of 700 million cubic feet per day."

That compares quite favorably with the Barnett. Devon's net production from that North Texas shale play stood at nearly 1.2 Bcf a day during the fourth quarter of 2008.

Northwestern story

While Devon, EnCana, and Apache are occupied in the east-central slice of the basin, there's another theater of activity on its northwestern side.

EOG Resources Inc., Quicksilver Resources Inc., Stone Mountain Resources Ltd., and Ramshorn Canada Investments Ltd. each have sizeable positions in this corner. Their areas of interest lie east of the Bovie Fault and gas infrastructure serving Maxhamish Field.

Private firm Stone Mountain Resources Ltd. was formed in April 2006. It's backed by First Reserve Corp. and Quintana Energy Partners LP, and the balance is owned by management and a few Calgary-based individuals.

"Initially, we were a conventional player looking at Northeastern British Columbia," said Harvey Klingensmith, president and chief executive. Stone Mountain bought a small public company that held some scattered acreage in the Horn River Basin, and the leases were expiring.

In winter 2007-08, it drilled a pair of vertical wells to extend licenses on two parcels of acreage. It cored and logged the wells, and was deep into its evaluations when news of the basin's potential began to break.

Stone Mountain has partnered with Ramshorn Canada Investments, a subsidiary of Nabors Industries, on the Horn River acreage. The pair formed the Stone Mountain Venture Partnership, operated by Stone Mountain Resources. The entity holds 37 sections of land. Ramshorn has an adjoining 34-section block that it holds 100% as well.

To date, the partnership has completed one vertical well and drilled and completed two horizontals. A third horizontal is currently in completion, and a fourth is being drilled. Additionally, Stone Mountain is operating the construction of a 60 MMcf/d gas plant, which will be owned by Ramshorn Canada.

Stone Mountain has not yet released test results, but is encouraged by what it has seen, said Klingensmith. "Our drilling results have been very good, and we consider this a world-class shale gas play."

The operator has built two 20-acre pads, each capable of hosting up to 24 wells. At present, two wells are completed on the first pad and two are drilled on the second. Its total for 2009 will be seven horizontals, split between the pads.

Work can continue year-round and production from the initial batch of wells will start shortly. That's because last year the partners built a 10-mile (16-km), all-weather road and laid a 15-mile (24-km), 12-in. pipeline to connect their gas to Spectra's Maxhamish system. The road, which joins the Fort Liard highway, qualified for British Columbia's infrastructure credit, a nice boost.

After Stone Mountain put in the road, it made a deal with neighboring operators EOG, Ramshorn, and Quicksilver that allowed them use as well. "It's an example of parties working together to utilize the infrastructure in a very remote area," said Klingensmith.

"We expect this to be a major producing area for 30 to 40 years, and we're in it in the beginning," he said. "At current gas prices, the economics of the Horn River are not as robust as we would like, but we are thinking in longer terms."

Market options

While the Horn River Basin has no infrastructure in its middle, its eastern and western flanks have produced gas for decades. For more than 40 years, Calgary-based Spectra Energy Corp. and its predecessor companies have operated more than 600 miles (966 km) of gathering lines along the basin's sides.

Additionally, Spectra's Fort Nelson plant is one of the largest sour-gas processing plants in the world. Built to handle gas produced from Slave Point reefs, the Fort Nelson gas plant currently operates at half of its 1 Bcf/day capacity.

Spectra recently held an open season and received firm commitments of 760 million a day for gathering and processing capacity from seven Horn River Basin producers. Starting this year, Spectra plans to reactive existing capacity at its Fort Nelson plant and add new processing capacity at its Cabin Lake compressor station.

Initially, Horn River Basin operators expect to fill up the Spectra system. Beyond that, a group, headed by EnCana and including Devon and Apache, plans to build a processing plant at Cabin with initial capacity of 400 million a day. "That will be in addition to Spectra and will be onstream in 2011," said EnCana's Graham.

EnCana is applying for approvals for a plant with capacity of 800 million a day, but that can be further expanded in 400-million-a-day increments depending on future needs and regulatory approvals.

Gas sold into Spectra's system travels south and east through British Columbia to markets in the Pacific Northwest. "We eventually want to access eastern markets as well," said Graham. A connection from Cabin to the Nova system would allow Horn River gas to travel to those premier destinations.

So, the Horn River has all the right stuff: thick, attractive shales; encouraging drilling results; long-lasting land positions; and connections to markets. Its development may be slower in this price environment than it would have been a year ago, but it will certainly be developed and will, within a few years, take its place among the top gas-producing basins on the continent.

Hardy Horn River Operators Face Challenging Play

An overview of the key companies working in remote Northeast British Columbia underscores the basin's obstacles and potential.

Apache Corp.

Apache Corp. moved in early and on a large scale to make itself one of the top shale players in the Horn River Basin in Northeast British Columbia.

Although it's not known as a shale chaser in the US, Apache saw an opportunity in Canada as an earlier play evolved into the shale opportunity.

Apache started work in the Ootla area of the Horn River Basin in 2001 as it drilled to the Keg River dolomite. Like all operations in that area, drilling ground to a halt as winter passed and the muskeg turned to mush. By 2004, the company decided the Keg River wouldn't meet the company's profit expectations, and it started looking for alternatives.

It found that opportunity when it noticed a gas crossover effect on density and neutron logs in the Muskwa and Klua shales at depths shallower than the Keg River.

By the end of 2008, Apache and EnCana accounted for half the wells drilled in the play, and they plan another 40 wells in 2009 in spite of the drop in gas prices during the past year.

Apache completed seven horizontal wells in the Ootla area in the basin in 2008. The latest well in the series used a 10-stage frac treatment and tapped an estimated 7.4 Bcf of gas reserves.

During a 2008 review for analysts, John Crum, president of Apache Canada, outlined the play's potential for Apache. Growth potential includes between 9 Tcf and 16 Tcf of net gas reserves.

Apache expects strong growth from the play over the next five years and the play is on the planning board for commercial production.

Apache's 221,625 net acres in the center of the play holds a gas-in-place accumulation of hundreds of trillions of cubic feet of gas. It contains between 100 Bcf and 200 Bcf of gas per section.

Apache drilled seven horizontal wells in 2008 and results exceeded the company's planning, he said, and gas from completed wells flows into Apache's Missile gas processing facility.

During 2009, Apache plans to confirm its development model.

Development plan

Apache and partner EnCana are working on an aggressive and well-formed plan for their area of mutual interest.

They looked at the play and determined they could drill vertically to about 8,500 ft (2,591 m) to the Muskwa/Otter Park Shale and then drill horizontally to 13,000 ft (3,962 m) measured depth. There, 320 ft (98 m) of Muskwa/Otter Park lies on top of 150 ft (76 m) of Klua/Evi Shale. A 60-ft (18 m) carbonate seal separates the two zones. To reach the Klua/Evi shale, the companies can drill vertically to 8,800 ft (2,682 m) and then go horizontally to 14,000 ft (4,267 m).

The companies are working in two main areas, Dilly and Two Island Lake.

During 2008, Apache drilled the a-13-J well with six fracture treatments, 2.1 million lb of sand and 3.3 million gal of water and produced from the Muskwa. Its c-99-H well also used six fracs. It took 2.9 million lb of sand and 3.7 million gal of water. The a-100-H well, with six fracs, used 4.1 million barrels of sand and 4.8 million gal of water. It also drilled the d-91-G, a microseismic listening well.

Apache drilled the wells northwest and southeast from a single pad. Production from the pad moves through a 6-in. pipeline to the company's Missile plant 17 miles (27 km) to the southeast. That plant has 23 MMcf/d of gas-processing capacity, and the company can expand to 45 MMcf/d. It also can relay raw gas from Missile south to Ft. Nelson to a plant with 450 MMcf/d of spare capacity.

At Two Island Lake in 2008, Apache drilled wells with horizontal legs reaching north-northwest and south-southeast. It drilled one set of wells from the b-76-K pad. There, it drilled the b-D76-K well to the Klua and completed it with four fracs, 1.2 million lb of sand, and 18 million gal of water. From the same pad, it drilled the b-C76-K south-southeast to the Muskwa and completed it with 10 frac, 5.3 million lb of sand, and 8.4 million gal of water.

The company also drilled the d-70-J well from the D-70-J pad. That well had eight fracture treatments with 8.5 million lb of sand and 7.1 million gal of water. Gas from Two Island Lake wells moves 10 miles (16 km) east to the Missile plant.

Those wells gave the company a solid foundation of the effectiveness of treatments in the deep shales.

Results

According to Apache, the 10-fracture treatment produced an initial potential of 7.3 MMcf/d of gas and an estimated ultimate recovery (EUR) of 7.6 Bcf of gas from the Twin Island West pad. Eight fracs at the Twin Island East pad showed an initial potential of 4.9 MMcf/d of gas and an EUR of 5.5 Bcf of gas. Six fracs at Dilly offered an initial potential of 3.3 MMcf/d of gas and an EUR of 4.1 Bcf of gas. Finally, four fracs in the Klua at Twin Island released an initial 2.5 MMcf/d of gas and an EUR of 2.3 Bcf of gas.

A well with a 10-frac treatment declines to about 2 MMcf/d of gas after 24 months and to about 200 Mcf/d of gas in 20 years.

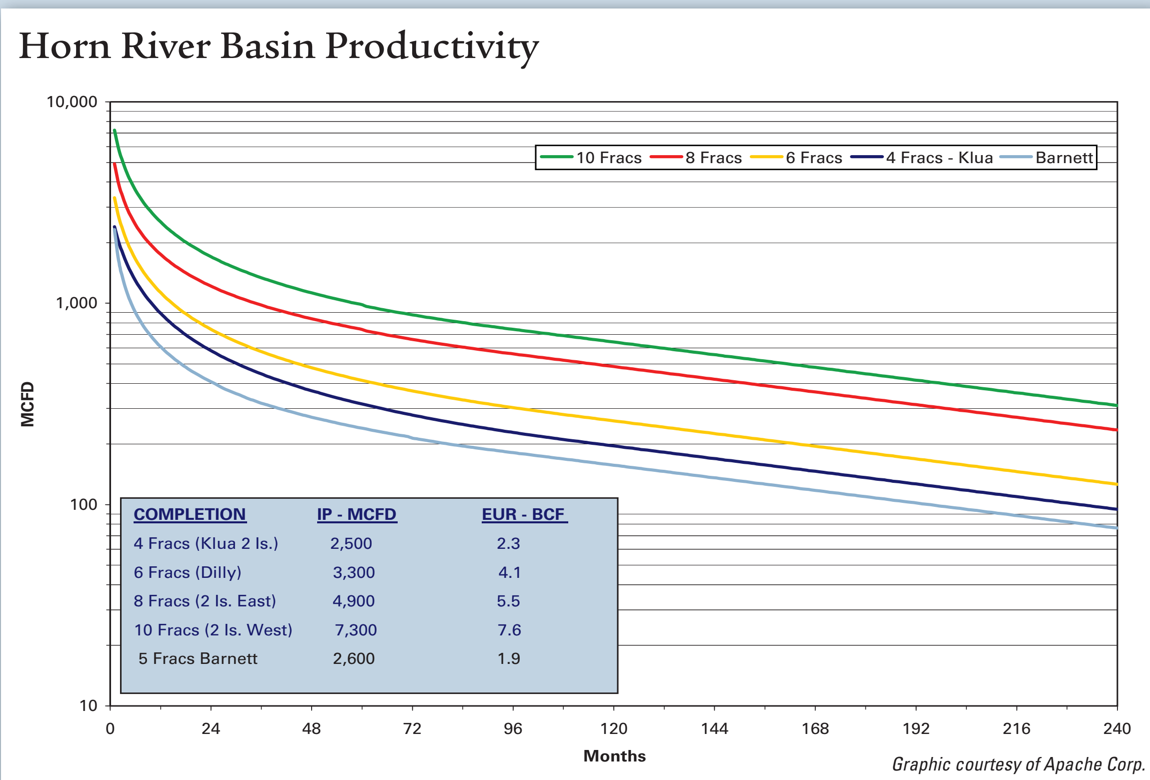
For contrast, the company said five fracs in the Barnett Shale of North Texas offer an initial potential of 2.6 MMcf/d and an EUR of 1.9 Bcf of gas.

Development concept

Under the companies' concept for development, EnCana and Apache could drill 28 horizontal wells on a pad – seven wells northwest and seven wells southeast to the Muskwa, and seven wells northwest and seven wells southeast into the Klua.

Under that concept, each pad would cost US $220 million through drilling, completion, and tie-in and produce 80 MMcf/d to 100 MMcf/d in the first year of production. Ultimately, each pad would recover 150 Bcf of gas.

That recovery assumes 150 Bcf of gas-in-place per section and 400 Bcf of gas-in-place per pad. Horizontal wells from each pad would cover 2.7 sq miles (7 sq km) with horizontal legs 5,400 ft (1,646 m) long and spaced 820 ft (250 m) apart.



Apache calculated estimated ultimate recoveries from different frac treatments and initial production rates.

Apache and EnCana plan six pads under that concept in 2009, but most of the wells will go to the Muskwa with Klua development to follow.

Economics

Apache already has worked out the economics for the 40 wells in the 2009 program.

The wells will cost $3.5 million (CAD $3.8 million) each to drill for a total $140 million ($151.8 million). Another $200 million ($217 million) will complete the wells at $5 million ($5.4 million) each, and $8 million ($8.7 million) more, or $200,000 ($216,957) per well, will tie the wells to the 6-in. line to the Missile station. That part of the project will cost a gross $348 million ($377.3 million).

Compression and dehydration will add another $55 million ($59.6 million) and a 24-in. pipeline will cost $80 million ($87 million) more. Water systems will add $36 million ($39 million) and pre-spending for the Cabin gas plant will take another $10 million ($10.8 million). Pads, roads, and facilities will up the ante by another $31 million ($33.6 million). That phase will take a gross $212 million ($229.8 million).

The gross total for the 2009 program will be $572 million ($620.5 million) for the two companies or $260 million ($282.2 million) net to Apache.

The development program assumes 5,400 ft (1,646 m) of lateral well in the producing formation and fracture spacing at 500 ft (152 m).

The average per-well initial potential will reach 7.3 MMcf/d and an EUR of 7.5 Bcf of gas. That will give Apache net reserves of 75 Bcf of gas from the 2009 program at a finding cost of $12.32/boe, or $2.05/Mcf at an energy equivalent value of 6 Mcf of gas to 1 bbl of oil.

Figuring a $5/MMBtu gas price on the New York Mercantile Exchange, less a $2.38 wellhead differential, the companies would get a wellhead price of $2.62/MMBtu for a 1.5% return.

At $6 gas, the return climbs to 7.5%, and at $7 gas, the return grows to 13%, according to Apache's figures.

In Northeast British Columbia, leases are good for four years. Wells earn more time and longer horizontal wells earn still more time on more land. For example, a 5,400-ft (1,646 m) Horn River horizontal well, as planned by the two companies, will earn 24 sections of land for 10 years. In all, 14 wells will validate Apache's full position in the play, and approximately 110 wells over the 10-year lease will hold the full acreage position by production.

Meanwhile, the government is working with the industry to minimize drilling footprints and maximize production as it anticipates more than 3,000 wells in the play area. The shale play also has potential for additional recovery from waterfloods and enhanced recovery techniques.

Canadian Natural Resources Ltd.

Canadian Natural Resources takes on projects around the world with high potential, but the company won't appear on anyone's follow-the-crowd list. It has production offshore Cote d'Ivoire, Africa. The company started production at the end of February 2009 on its Horizon heavy oil sands project and it is developing thermal production of heavy oil deposits.

Canadian Natural Resources also holds substantial conventional and unconventional natural gas properties in Alberta and Northeast British Columbia in Canada.

It held 2.23 million net acres covering conventional resources in Northeast British Columbia in 2007, but the company's position in the Horn River Basin was only a small part of that total. That small part, however, represented a potential 1.35 Tcf of gas in the Muskwa Shale.

According to a May 2008 presentation, Canadian Natural Resources had defined two Muskwa prospects and an ultimate drilling potential of 800 wells.

A later presentation said nearly 90% of net risked drilling additions over the next 10 years would be aimed at the Montney shale-silt-tight sand and Muskwa Shale plays and the company considered both plays part of its core operations.

It currently has no Muskwa wells, but they definitely are in the corporate plans. According to a 2009 presentation to analysts, it plans to begin drilling operations to the popular shale in 2010, drill five wells in 2011, eight wells in 2012 and 10 wells each in 2013 through 2018.

Its production projections anticipate start of Muskwa gas in 2011 with production ramping up to about 50 MMcf/d of gas in 2015 and to some 80 MMcf/d of gas in 2018.

Under the company's 10-year plan, its Muskwa Shale resource potential should reach 375 Bcf of gas.

Cougar Energy Inc.

Kodiak Energy Inc. created Cougar Energy Inc. early in 2009 to conduct operations on the company's CREEnergy joint venture in North Central Alberta and its Lucy project in the southeast section of the Horn River Basin and the shale play.

Photo courtesy of Devon Energy Corp.

The subsidiary arrangement allows Kodiak to fund those projects as a separate entity and to avoid diluting the company's existing projects.

Kodiak acquired its interest in the Lucy prospect as a 10% working interest from Highwood Exploration (Canada) Inc. in 2006 as one of a group of companies participating in the prospect 40 miles (64 km) north of Fort Nelson, British Columbia.

At that time, the companies were looking for production from the deeper Keg River formation. The prospect included some 3 sq miles (8 sq km) of land.

An early 2008 well didn't find a Keg River interval, but the shallower Muskwa and Evie shales looked interesting, and other companies had started working those shales farther to the north. By early 2008, Kodiak raised its working interest in the property to 80% and became the operator.

It had drilled vertical wells by that time and found a Muskwa pay zone of up to 197 ft (60 m). A laboratory analysis showed 3.68% average total organic content with peaks as high as 5.7%. That suggested to Kodiak management a resource of 20 Bcf of gas per section. As a result, the company got an extension of its lease with British Columbia to change its target.

By May, Kodiak planned to perforate, fracture, and test its early 2008 vertical well, the a-79-A well, in the Evie Shale in 2008 and follow up with a horizontal leg into the Evie from its previously drilled d-90-A well with a multiple-stage completion in 2009. That, the company said, would allow it to compare productivity of horizontal and vertical wells.

The company already had averaged the high and low estimates to come up with 32 Bcf/section of gas in place. It also estimated a recovery factor of 55% and a surface loss of 10%.

That led Kodiak to total prospective marketable resources for the Lucy project of 3.01 Bcf on the low side, 10.32 Bcf of gas as a best estimate at 17.64 Bcf of gas on the high side for recovery. It also estimated a horizontal well would yield twice the reserves of a vertical well.

It offered a best estimate of 750 Mcf/d of initial potential for a vertical well and 2 MMcf/d of gas initially for a horizontal well, based on experience at that time reported by other operators.

"Upon proving up the Muskwa shales to our expected potential, we can either move it into long-term production or divest it to one of the adjacent large industry neighbors who can use the expected results to validate their properties," said Bill Tighe, president and chief executive officer of Kodiak.

By October, the company had set a budget to complete the vertical well and planned to move equipment for a slickwater fracture treatment into the area in November when the ground had frozen.

At the same time, it planned the horizontal re-completion in the Evie with a 2,424-ft to 3,281-ft (800-m to 1,000-m) horizontal leg and a large, staged frac treatment.

Following successful testing and determination of commercial potential, the company planned to hook the wells into the existing pipeline system in the area.

Crew Energy Inc.

Crew Energy Inc., working off a high-growth curve in its Canadian operations, is making big plans for its Horn River Basin properties as it comes off a slow start.

The company looks for assets that will allow it to effectively apply new technologies, particularly significant resource plays. The technique apparently works. According to a January 2009 presentation, reserves grew from about 2 million boe in 2003 to more than 45 million boe at the end of 2008.

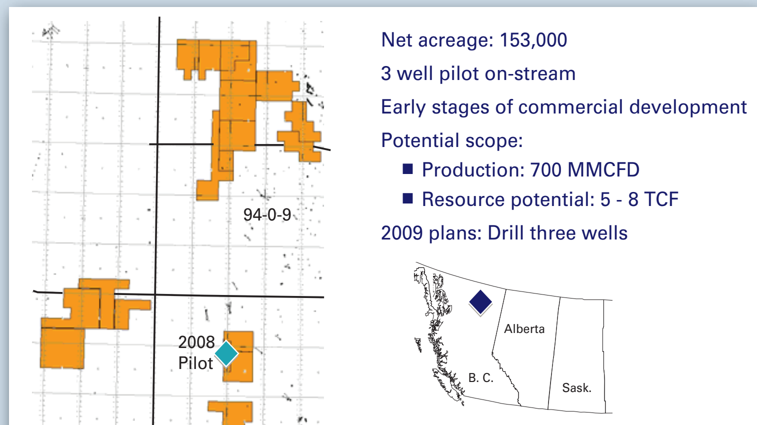
The company holds 323,047 gross acres, 155,904 net, undeveloped acres in Northeast British Columbia and has active operations in the Montney shale-silt-tight sand play.

Crew bought a private oil and gas company in May 2007, to get 3,100 boe/d of production. That purchase also gave it "a foothold land position" in the Muskwa.

That foothold is in the northeastern segment of the company's Sierra area in a 65-mile (105-km) radius around Fort Nelson, British Columbia. It includes 15 net sections in the Horn River Basin prospective for Muskwa Shale production.

Its slow start in the Muskwa Shale in the Horn River Basin included one horizontal drilling location and tie-in candidate southeast of the Apache-EnCana properties and one recompletion candidate to the south.

Devon is just beginning its work in the Horn River play with a three-well pilot in 2008 and another three wells planned in 2009.



Graphic courtesy of Devon Energy Corp.

Plans for the future are a lot bigger than that. The development plan calls for drilling from up to four pads with as many as seven horizontal wells per pad, initially. In the first drilling phase, it will concentrate on the Muskwa, the topmost shale layer.

It plans to drill vertically to about 7,875 ft (2,400 m) and drill horizontally to the northwest for another 3,609 ft to 4,922 ft (1,100 m to 1,500 m).

Subsequent horizontal wells will drill to the deeper Otter Park and Evie shales in the 509-ft (155-m) shale series.

The company's 2009 plans include additional work in the 184 net acres in the Montney play, where it has 12 wells. Crew Energy will continue work in its Septimus area there. But the company has no apparent plans for the Muskwa in 2009.

Devon Energy Corp.

Devon Energy, the top producer in the Barnett Shale of North Texas, is transferring its knowledge of shale plays to the Horn River Basin in Northeast British Columbia.

Devon has 153,000 net acres under lease in the basin and brought a three-well pilot program onstream in early 2009. Devon said the project is still in early stages of commercial production, but it set a goal of 700 MMcf/d of gas from potential resources between 5 Tcf and 8 Tcf of gas, according to Chris Seasons, president of Devon Canada, speaking at a Peters & Co. conference in Toronto.

Devon's pilot project in the Horn River Basin represents only a fraction of the company's drilling activity. In 2008, Devon drilled 2,441 total wells, 659 of them in the Barnett Shale. That doesn't mean the emerging shale play is insignificant for Devon.

"This is not small by any stretch of the imagination," Seasons said, according to an article by The Canadian Press. "Cost control is going to be an issue out here. Getting this thing onstream economically is going to be the challenge for us.

"We're not drilling in the outskirts of suburban Dallas. We're drilling up in the bush. My concern is that there will be a real shortage of technical staff and skilled trades to make this all happen," Seasons said. Add to that the technical problems of drilling and fracturing horizontal wells in frigid temperatures in the winter and restricted access in the summer when the muskeg thaws.

In spite of the obstacles, Devon said the play is promising. It plans only three more wells in 2009, according to an analyst presentation in February 2009.

Table courtesy of EnCana Corp.

	Fort Worth Barnett	Delaware Barnett	Maverick Pearsall	Piceance Niobrara	Haynesville	Horn River	Montney*
ECA Basin Entry Year	2003	2004	2005	2006	2005	2003	1998
ECA Acres (Net)	143,000	600,000	255,000	410,000	435,000	260,000	731,000
Basin Natural Gas in Place (Bcf/Section)	100-150	100-150	125-175	100-200	175-225	150	25-300
Average Drill Depth (ft)	8,000	10,000	9,000	9,000	12,000	9,000	9,000
2009F Wells (Gross)	40	1	4	0	58	40	63
Indicative IP (MMcf/d)	1.7	1.0-5.0	1.0-3.5	1.7-4.0	10.0	5.0-10.0**	5.0-10.0**

**The Montney play is a turbidite rather than a shale, but is included here for comparison purposes as it exhibits some similar resource characteristics and development techniques.*
***Frac Interval number-dependent*

The Horn River Shale play compares favorably with other resources plays in EnCana's portfolio.

EnCana Corp.

EnCana Corp. set its sights early on resources plays in the US and Canada, so it is no wonder it one of the top leaseholders, top drillers, and pioneers in the Horn River Shale play in Northeast British Columbia.

It started work in the Horn River Basin in 2003, accumulated some 260,000 net acres in the sweet spot of the play, and formed an equal interest venture with Apache Corp. to explore and develop more than 400,000 acres. The land position makes EnCana the largest leaseholder in the Horn River Shale play.

The best horizontal well to date flowed an average of nearly 8 MMcf/d of gas for the first 30 days of production.

It plans 40 wells with Apache during 2009, according to an early 2009 presentation, with an average drilling depth of 9,000 ft (2,743 m) to reach 150 Bcf of gas per section from wells with initial potentials between 5 MMcf/d and 10 MMcf/d of gas.

The company's third-quarter 2008 report said the partnership had completed seven wells during the year, including the 8 MMcf/d well. EnCana's second quarter report said it had two wells with a first-month average of more than 5 MMcf/d of gas.

EnCana continued to accumulate land in the play during the year. Its first quarter report showed only 216,000 net acres in the basin. It said Apache had drilled the first three wells in the 2008 program with initial potentials of 8.8 MMcf/d, 6.1 MMcf/d, and 5.3 MMcf/d of gas, and with the help of British Columbia's infrastructure program, an all-weather road was built into the area to help overcome the summer drilling restrictions when the Muskeg turns to marshland. The road will allow year-round drilling, EnCana said.

Apache Corp. offered some insight into the partnership's plans in a presentation to analysts by Apache Canada President John Crumm.

The companies are working on a concept under which they could drill up to 28 horizontal wells on a pad. They would drill wells to the northwest and southeast with seven wells in each direction to the Muskwa Shale at about 8,000-ft (2,438-m) vertical depth and seven wells in each direction to the Klua Shale at about 8,800-ft (2,682-m) vertical depth.

The companies would expect each 2.7-sq-mile (8-sq-km) pad to recover 150 Bcf of gas with the well groups producing 80 MMcf/d to 100 MMcf/d in the first year of production.

That recovery assumes 5,400-ft (1,646 m) laterals with 820-ft (250-m) spacing between the lateral legs.

The pad cost, through tie-in to the gathering system, would total US $220 million, according to Apache.

The companies plan to start drilling six of those pads in 2009, but most of the early wells will bottom in the shallower Muskwa.

From wells already drilled in the partnership, Apache said a 10-frac program in a long-lateral well with fracture treatments every 500 ft (152 m), results in an initial potential of 7.3 MMcf/d of gas and an estimated ultimate recovery of 7.6 Bcf on the Twin Island West pad in the companies' area of mutual interest.

For contrast, eight fracture treatments of the Twin Island East pad offered an initial potential of 4.9 MMcf/d of gas and an estimated ultimate recovery of 5.5 Bcf of gas.

That process of tests with increasing numbers of fracture treatments and increasing volumes of sand and water in the treatments led to the current concept for development by the two companies.

EOG Resources Inc.

EOG Resources Inc. (EOG) operates in the Horn River Basin in Northeast British Columbia where it is targeting the Muskwa Shale, which the company feels has world-class rock properties.

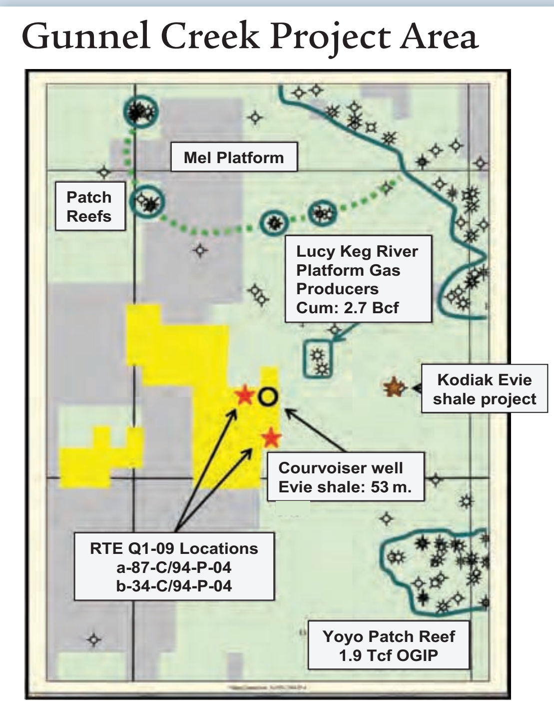
With shale thickness of approximately 500 ft (152 m), the Muskwa Shale has even better rock quality than the Fort Worth Basin Barnett Shale in North Texas, where EOG has been very active.

With 157,500 net acres currently under lease, EOG drilled six horizontal wells during 2008. The company's third-quarter 2008 earnings report said it had drilled and completed three horizontal wells with initial production rates of 16 MMcf/d, 12 MMcf/d, and 9 MMcf/d, respectively. The wells continued to produce at strong rates after 30 to 60 days online.

By year-end 2008, EOG had drilled eight horizontal wells in the Horn River Basin and seven of those were flowing to sales. First production began in July 2008. The company anticipated drilling seven more horizontal wells during 2009.

EOG estimated there could be approximately 6 Tcf in potential natural gas reserves on its Horn River Basin acreage, assuming 60% of its acreage is drillable and the company's estimate of recoveries of 25% of the natural gas in place is accurate.

Result and Pen-Growth planned two wells in the Gunnel North area in the first quarter of 2009 and the companies are looking for more land.



Map courtesy of Result Energy Inc.

EOG is initially working the west side of the Muskwa Shale play, where it has access to an existing pipeline that has the capacity to meet near-term production even without expansion. EOG's current sales line capacity is 25 MMcfd to 100 MMcfd.

Production volumes should increase in 2012 when additional industry pipeline infrastructure is added in this remote area north of Fort Nelson. EOG expects the Horn River Basin will be one of the company's drivers for increased natural gas production in the future.

Imperial Oil Ltd./ ExxonMobil Canada Ltd.

ExxonMobil Canada Ltd., with ExxonMobil Corp. affiliate Imperial Oil Ltd., identified the Horn River Basin shales as a key resource area for the company and started acquiring acreage in the shale gas play late in 2007.

The ExxonMobil 50:50 partners entered the play later than some of the other major players, but the affiliates of the world's largest public company, only reaches for plays that will make a noticeable movement in the companies' on the dial of reserves and production, and that's a difficult dial to move.

It clearly likes the Horn River shales play. Since that late September 2007 start it acquired 115,000 net acres in the play by April 2008, and raised that to 152,000 net acres by the end of that year. Generally, those properties are about 43 miles (70 km) north of Fort Nelson, British Columbia, and less than half that distance south of properties undeveloped by the other major players in the gas shales.

The companies also joined the Horn River Basin Producers Group. That group recently joined Geoscience BC to investigate aquifers in the Horn River Basin as sources of drilling and completion water and to look at zones for possible disposal of produced water and carbon dioxide. The group also works with stakeholders in the area, including First Nations people.

The ExxonMobil team started drilling the first well in a four-well test series late in the fourth quarter of 2008 to test resource quality and productivity, according to Bruce March, chief executive of Imperial.

In the company's third-quarter 2008 conference call for analysts, recorded on www.seekingalpha.com, David Rosenthal, ExxonMobil vice president of investor relations and secretary, listed the Horn River Basin as a key resource and upstream growth area for the company, along with the Mackenzie Delta, the Alberta oil sands, and the Orphan Basin offshore eastern Canada.

That was just one of the highlight projects the company pointed out in its fourth-quarter report. Others picked out for special attention by Imperial were that company's Kearl oil sands project, its Cold Lake heavy oil project, facilities improvements at the Syncrude production complex, and a 3-D seismic program in the Beaufort Sea offshore northern Canada.

ExxonMobil executives told analysts at the 2008 Reuters Global Energy Summit in Houston that it will put more into large-scale unconventional gas plays in the future.

Nexen Inc.

Nexen Inc. put together a significant chunk of acreage in the Horn River Basin as it jumped in the increasingly popular shale play in Northeast British Columbia.

During 2007 and 2008, the company pulled together some 126,000 net acres. It also has invested capital over the past two years to learn how best to develop the play, primarily in the Dilly Creek area, where it holds 88,000 net acres.

That area offers a gross shale interval 574 ft (175 m) thick, or nearly 50% thicker than the Barnett Shale in North Texas, the company said. During its winter 2007-2008 campaign, the company fractured three vertical wells and one horizontal well with “encouraging results.” Those results prompted the company to seek an analysis from outside consultants. Those consultants convinced the company its properties around Dilly Creek held between 3 Tcf and 6 Tcf of recoverable natural gas.

Those recoverable volumes potentially double company-wide proved reserves, Nexen said in a year-end 2008 status report.

It drilled two more horizontal wells during the summer of 2008 and fractured the wells late in the year. It also worked with other companies in building an all-season road into the area so it could work year-round instead of halting operations from the spring thaw until the fall freeze. Nexen also reserved 70 MMcf/d of pipeline and processing space to handle shale gas production for the next five years.

The company also listed the reasons it liked the Horn River shales. The resource potential complements its long-cycle-time portfolio and increases its exposure to natural gas. It could provide predictable cash flow for many years. Since Nexen had early-mover advantage, it picked up land that now leases for 10 times the amount the company paid.

Generally, Nexen's properties are east of the Apache/EnCana and Devon properties and southeast of the EOG holdings in the play.

For 2009, Nexen plans a multiple-well program, but it hasn't yet started listing potential production from the Horn River Basin in its 2009 estimates. It does plan to sanction activity and book reserves in the basin. It will spend US $123.12 million (CAD $160 million) of its $1.97 billion ($2.56 billion) 2009 capital expenditures in the Horn River Basin.

Work during 2009 will focus on optimizing drilling and completion techniques and drilling seven horizontal wells from a single pad, according to a December report from the company. In July, Nexen had projected an eight- to 16-well drilling program to Horn River shales in 2009.

PenGrowth Energy Trust

The PenGrowth Energy Trust investment trust arm of PenGrowth Corp. takes a conservative approach to investment, but the Horn River Basin shale play is attractive enough and offers a risk profile that even a conservative company finds attractive.

Even as plunging prices and plunging economies took many unconventional plays off the operations charts of oil and gas companies, PenGrowth will invest in the Horn River shales in 2009.

PenGrowth controls 98 gross sections, 71.5 net sections, with 11 drilling licenses in the Horn River Basin.

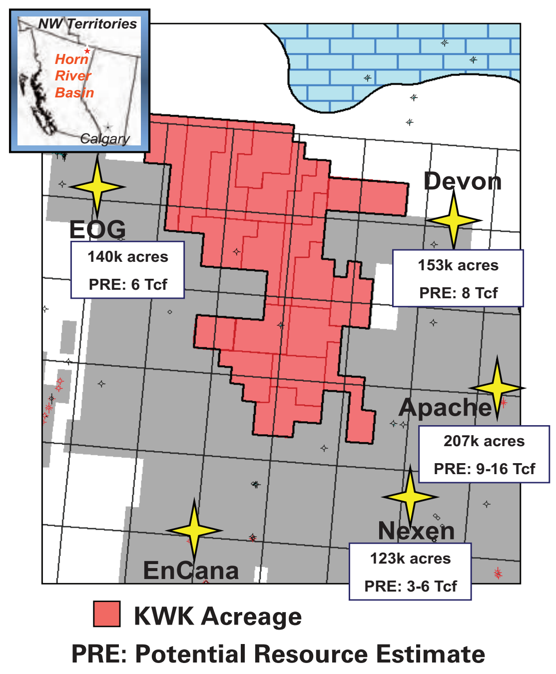
It controls Gunnel South properties on its own and shares control of Gunnel North properties with Result Energy Inc. Result calls the north properties Gunnell Creek.

The PenGrowth lands lie between EnCana's Etsho prospect to the south and EnCana's Snake River prospect area to the north.

Result and PenGrowth acquired an interest in 18 sections next to Result's 25 sections in the Gunnel North area. That deal gave PenGrowth a 40% interest in 43 sections. Result bought and interpreted 3-D seismic data over part of the Gunnel properties and found promising targets in the Devonian shales.

Result, as operator, planned the a-87-C/94-P-4 well and a follow-up with the a-85-C offset in the first quarter of 2009. Following that well, also in 2009, the companies planned their first Evie and Otter Park shales horizontal well, also offsetting the a-87-C well, according to a

Property controlled by the biggest operators in the Horn River Basin shale play surround Quicksilver properties on three sides.



Map courtesy of Quicksilver Resources Inc.

PenGrowth presentation to analysts. That program will cost some US $7 million (CAD $9 million), and, depending on earning options, PenGrowth's would pay $4.44 million ($5.7 million) or $3.58 million ($4.6 million).

Result's three-year plan for Gunnel North called for one vertical and three horizontal tests in 2010 plus construction of gathering lines and a processing facility.

The 2011 plan anticipated two horizontal wells in the area.

Petrobank Energy & Resources Ltd.

Petrobank Energy & Resources Ltd., already a significant operator in the Bakken Shale oil and heavy oil plays, took a substantial position in unconventional gas plays in Canada with acreage in the Montney shale-silt-tight sand resource play and the Horn River Basin shales.

According to the company's year-end 2008 report, "We intend to capitalize on our evolving experience with advanced fracturing technique with the goal of building a substantial, long-term inventory of drilling locations at a low near-term cost."

During the past year, the company acquired 65 sections of 100% working interest land at Crown sales in the Horn River Basin and picked up a 15.5% interest in another 14 sections of land.

It started drilling its first horizontal well to the Horn River shales on its Evie prospect in late February 2009. That prospect lies close to an existing pipeline and near all-weather access near the Alaska Highway. That access allowed Petrobank to complete its horizontal test during the second quarter of 2009.

"Our immediate focus will be on drilling test wells and developing a multiyear inventory of drilling locations in the Muskwa and Evie shales. No reserves have been assigned to our Horn River asset base as at Dec. 31, 2008," the company said in the year-end report.

Petrobank also holds the Snake and Julia prospects in separate areas of the basin, areas without full-year access. An existing gas pipeline runs near the Julia prospect east-northeast of Fort Nelson, British Columbia.

Petro-Canada

Petro-Canada has a worldwide portfolio of high-potential oil and gas projects. It has taken a position in the search for Horn River Basin shales, but that search doesn't count among the company's top-ranked plans for the future.

For example, it has properties in the northwest extension of the Montney play in British Columbia, Horn River Shale basin, and the Cordova Shale basin east of the Horn River Basin along the British Columbia border with Alberta.

Petro-Canada already laid plans for its major operations through 2020. Those plans include operations in Libya, offshore eastern Canada, heavy oil in Canada, natural gas offshore Trinidad, oil from the National Petroleum Reserve-Alaska, natural gas from the Mackenzie Delta in northern Canada, and gas from the Canadian Arctic islands.

The company holds 72,000 acres in the Yoyo area in the southern Horn River Basin east and a little bit north of Fort Nelson. It started a pilot project there during the past winter with one vertical and two horizontal wells. It also holds properties south of the basin and south of Fort Nelson.

Petro-Canada also controls 23,000 acres in the Cordova Shale basin, but its corporate presentations didn't offer any plans for operations there over the past winter.

Also in the new unconventional plays, Petro-Canada holds 77,000 acres in the Kobes region in the extension area northwest of the proven Montney play. It holds another 18,000 acres in the play a short distance to the south in the Altares and Farrell Creek region. It planned a two-well pilot in the Kobes area during the winter.

Quicksilver Resources Inc.

Quicksilver Resources Inc., a solid producer in the Barnett Shale of North Texas and the Horseshoe Canyon coals in Alberta, turned its sights to the Horn River Basin on Northeast British Columbia early in 2008 with intentions to become a big factor in gas shale production.

The company announced in March 2008 it had acquired 19 licenses covering 127,423 net acres of land in the basin in Crown lease sales in late 2007 and early 2008. At that time, the leases cost an average US $511.49 (CAD $655) an acre. By that time, it already had identified more than 500 ft (152 m) of gross thickness in the Upper Devonian Muskwa and Klua shales at depths from 7,800 ft to 9,000 ft (2,379 m to 2,745 m) on its licenses.

In a March 2009 presentation, Quicksilver said the Horn River was the smallest of its resources plays in terms of acreage. It held 230,000 net acres in the Barnett Shale play with 1.9 Tcfge in reserve. That leasehold is less than 40% developed and the company has a 10-year inventory of drilling sites.

It held another 350,000 acres in the Horseshoe Canyon coalbed methane play with 333 Bcfe in reserves. That play is 27% development with 1,200 potential well locations.

The third resource play is in the Delaware Basin of West Texas, where Quicksilver held 375,000 acres of leases.

Quicksilver's Horn River Basin property lies east of EOG Resources' property with an estimated 6 Tcf of potential resources. It lies west of Devon Energy's 153,000 acres with an 8 Tcf potential resource estimate. It lies north and northwest of some 400,000 acres of Apache Corp. and EnCana Inc. joint venture properties with a potential resource estimate between 9 Tcf and 16 Tcf. It also lies northwest of 123,000 acres of Nexen leases with a potential resource estimate between 3 Tcf and 6 Tcf.

Quicksilver put two rigs to work on its Horn River Basin properties during the winter of 2008-2009. It planned to drill, test, and tie in two horizontal wells to test the Muskwa and Klua/Evie shales. It also built permanent roads to the drill sites and pipelines to the locations.

Ramshorn Investments

The Ramshorn Investments subsidiary of Nabors Industries in working its way into shale plays. It joined Southern Star Energy and Dynamic Resources in working the Haynesville Shale at Sentell Field in East Texas, and it has a stake in the Horn River Basin testing the Muskwa shales.

Ramshorn's position as a sister company to Nabors Drilling gave it a special position. Nabors has five PACE heli-portable rigs working in the Western Canada Sedimentary Basin, and four of them are the new programmable AC Arctic-configured bootstrap triple rigs capable of drilling to 14,765 ft (4,500 m). That depth rating will handle current Muskwa Shale horizontal wells and all but the deepest Evie Shale wells.

According to a February 2009 Oilweek article, Nabors could have delivered one of the new rigs to a Ramshorn well site by road, but it used the site to try its first air delivery of the newest rigs by helicopter.

It used a super-heavy-lift Russian MI-26 helicopter with a 20 long ton capacity, twice the lifting capacity of any North American helicopter, to move the rig nearly 10 miles (15 km) from the Liard Highway to the drill site. The move cost US $1.96 million (CAD $2.5 million).

"We wanted to get some learnings and make sure everything works. And everything worked extremely well," said Mike Read, Nabors' vice president of product development.

Ramshorn is drilling both to the Muskwa Shale and to the deeper Keg River Formation. If the Keg River doesn't pan out economically, the company could plug back to the shallower shale sections.

Ramshorn received authorization to drill two horizontal wells in the Tattoo area. In November 2008, it permitted the Tattoo a-056-B/094-O-15 to 14,187 ft (4,324 m), and in March 2009, it permitted the Tattoo a-A05-B/094-O-15 to 13,708 ft (4,178 m).

Result Energy Inc.

Result Energy Inc. represents the active junior operators in the Horn River Shale play as it teamed with industry partners to put together an active program for the future.

It's just one of more than a score of companies reaching for the estimated 500 Tcf of gas resources in place in the shales.

The Horn River fits Result's operations strategy, according to a November 2008 company presentation. The company likes to get into a play early when land prices are modest, find capital as it needs it, put together a proof-of-concept for a play, maintain a high working interest, leverage with large partners, and operate and manage the pace of development.

The company picked up its first 40 sections of land in the Horn River Basin before May 2008, and now holds 83 gross, 44 net, acres in three project areas.

Result holds licenses with Seven Generations Energy Ltd. in the Dilly Creek area east of Apache's Ootla properties. Result paid US $3.89 million (CAD $5 million) in stock for a 10% interest in 25 sections of land in that area.

In holds a 68% working interest in 53 gross sections of properties in Gunnell Creek south of Dilly Creek and east of the Lucy area. PenGrowth Energy Trust is a 40% partner in 43 sections.

Result holds properties on its own at Moss Creek, south of Gunnell Creek and east of the Evie area.

Result published a three-year plan of action for the properties.

During 2009, it will drill two vertical and one horizontal well and collect additional seismic for a net $3.11 million ($4 million) at Gunnell Creek. It will drill four horizontal wells and collect more seismic data at Dilly Creek for a net $2.33 million ($3 million), and it will invest $778,595 ($1 million) in seismic acquisition at Moss Creek.

The following year, it will drill one vertical and three horizontal wells for a net $11.67 million ($15 million) and install gathering lines and a processing facility at Gunnell Creek for a net $1.55 million ($2 million). Result will drill four horizontal wells at Dilly Creek for a net $2.33 million ($3 million), and it will drill two vertical wells at Moss Creek for $778,595 ($1 million).

The 2011 plans call for two more horizontal wells at Gunnell Creek for $9.33 million ($12 million) net to Result. Six additional horizontal wells at Dilly Creek for a net $3.89 million ($5 million) and two horizontal wells at Moss Creek for $5.44 million ($7 million).

That's a total of six vertical wells and 20 horizontal wells over the period for a net $42.74 million ($55 million).

Working through the Gunnell Creek numbers, Result said it figured 35 of the 53 gross sections were prospective, it anticipated 60 Bcf per section. That would give the company a 68% working interest in 1.43 Tcf of gross resources in place for a potential value of $776 million ($1 billion) at a netback between $1/Mcf and $2/Mcf.

In a July 2008 announcement of the land acquisition with PenGrowth, Result President and Chief Executive Officer Bill Matheson said. "We are extremely happy with our success at the recent land sale. With this new joint venture partnership in place, Result has cemented its position as the pre-eminent junior E&P player in the Horn River Basin. We have also increased our gross land position in this exciting shale gas play by 45%, while being able to manage project spending. As well, the recent prices paid in the south part of the basin resoundingly validate Result's strategy for Northeast British Columbia."

Seven Generations Energy Ltd.

Seven Generations Energy teamed with Result Energy Inc. to work the Dilly Creek prospect in the Horn River Basin shales in Northeast British Columbia.

Seven Generations picked up 25 sections of land in the basin during a British Columbia land sale. Result later came into the deal as it acquired a 10% interest in those properties in a stock trade valued at US $3.89 million (CAD $5 million). The acquisition gave Seven Generations 12.9% of Result's outstanding shares.

According to Result, the Dilly Creek area land is one of the more prospective areas in the Horn River Basin with more than 410 ft (125 m) of prospect Muskwa and Evie shales. The property is less than 12.5 miles (20 km) from the Trail a-26-G well, which tested at rates to 5 MMcf/d of gas after fracturing the Muskwa Shale.

Under Result's three-year plan, the companies will drill collect seismic data and drill four horizontal wells at Dilly Creek in 2009 at a net cost of $2.33 million ($3 million) to Result.

They will follow up in 2010 with four more horizontal wells at the same cost, and they will increase the program to six horizontal wells at a net cost of $3.89 million ($5 million) in 2011. Result estimates the full cost of a horizontal well to the shale zones costs approximately $5.44 million ($7 million).

Stone Mountain Resources Ltd.

Stone Mountain Resources Ltd. grew out of the confidence of a group of investment companies that opportunities existed in Northeast British Columbia and a tested and experienced management team could take advantage of them.

Among those investors were First Reserve Corp. and Quintana Capital Corp. Their foresight in 2005 created one of the most active smaller companies in the Horn River shales play. First Reserve owns about 80% of the exploration and production company.

Stone Mountain acquired Tenaka Field in Northeast British Columbia from Tenergy Ltd. to get its start and now works an active program in the Tattoo area of the Horn River Basin. The company also is a member of the Horn River Basin Shale Gas Producers Group.

In 2007, President and Chief Executive Officer Harvey Klingensmith helped Nabors Drilling Co. pioneer the use of its heli-portable drilling rigs to reach drilling sites in the remote area. The company planned five vertical wells to about 8,531 ft (2,600 m) in the winter of 2007-2008, according to an Oil & Gas Inquirer article.

The Nabors rig was heavy enough that it required a Russian MI-26 helicopter with twice the carrying capacity of any North American helicopter to make the moves. That rig was a telescoping double with a depth capacity of 9,843 ft (3,000 m). The rig also could have drilled through the spring breakup and continued work until the helicopter removed it.

During the 2008-2009 drilling season, Stone Mountain is drilling both to the Muskwa Shale and to the deeper Keg River in the Tattoo area of the Horn River Basin.

Between September 2008, and mid-March 2009, the British Columbia Oil & Gas Commission issued authorizations for Stone Mountain to drill seven horizontal wells and one vertical well to the Muskwa and deeper Evie shales.

The deepest Muskwa well was the Tattoo c-066-B/094-O-15 scheduled to 14,436 ft (4,400 m) measured depth.

The only Evie well in the series was the Tattoo a-B070-B/094-O-15. The company projected that well to 15,093 ft (4,600 m).

Storm Exploration Inc.

Storm Exploration Inc. knows the Horn River Basin territory, it knows how to work gas shales, and the company is bringing experience and knowledge to the Horn River Basin shales. It already has activities in the Montney unconventional gas play to the south of the Horn River Basin, and its Cabin, Kotcho, and Junior areas nearly border the basin on the east and south.

Together with 60% partner Storm Gas Resource Corp., Storm Exploration acquired 11,300 net undeveloped acres. Storm Exploration owns 23% of Storm Gas, and the partners acquired 43 gross acres in the Horn River Basin in 2008 at US $389.85 (CAD $500) an acre. Storm Gas was formed specifically to look for natural gas production opportunities such as the Horn River shales.

The companies drilled two vertical tests to the Muskwa and Otter Park formations on their properties west of their Cabin production area during the winter of 2008-2009. They planned to core and flow test at least one of the wells. They set aside $5.46 million ($7 million) for the two wells.

The core test should verify the companies' estimate of 80 Bcf of gas per section and that the formations contain 67% free gas and 33% adsorbed gas. The test also should prove up estimates of 3.8% average porosity, 2.5% total organic content, and 50% to 55% silica content.

If the vertical wells show commercial potential, the companies plan one to three horizontal wells on the properties in 2009 or 2010, according to a Storm Exploration presentation in early 2009.

The companies expect 1.9 Tcf of gas in place from just the Muskwa and Otter Park shales, but they said they didn't have enough information about the deeper Evie and Klua shales to estimate potential from those shales.

Trivello Energy Corp.

Trivello Energy Corp. used its early entry into conventional resource exploration in the Horn River Basin of Northeast British Columbia to gain entry into the emerging gas shale play.

The company joined a consortium of companies in developing the Lucy area in the Horn River Basin. That area looked attractive enough that Kodiak Energy bought 80% of the prospect and became operator. It later formed Cougar Energy to work the Lucy prospect.

Throughout the ownership changes, Trivello maintained its 10% working interest in the three sections in the play and in the Muskwa Shale potential on the property.

Partners had drilled and cased a vertical well to the shales in January 2008, and found 197 ft (60 m) of pay. The operator estimated some 87 Bcf in place, or a net 70 Bcf for the parcel. That well, the a-79-A 94-P-4, found an average total organic content of 3.68% and a maximum total organic content of 5.7%.

In the winter of 2008-2009, the companies planned a vertical staged fracture treatment in the Muskwa Shale for the well. After evaluation, if the well has commercial potential, they will tie it to the low-pressure pipeline that runs through the Lucy property. The companies also plan a 2,424-ft to 3,280-ft (800-m to 1,000-m) horizontal leg from one of the existing vertical wells on the property. That leg will tap the Muskwa/Evie Shale zone.

During the winter of 2009-2010 the partners will repeat the process with another vertical well, according to Trivello, and in the winter of 2010-2011, they will drill and tie in six infill wells.

River of Dreams

British Columbia's Horn River Basin has attracted more than a dozen players. With greater potential than the prolific Barnett, the excitement is palpable, but all is not rosy.

By Dick Ghiselin
Contributing Editor

Photo courtesy of Halliburton

Horn River is the hottest new play in Canada.

Some have taken the plunge, accumulating huge acreage positions and staking their experience and know-how against the whims of Mother Nature and the nuances of commodity prices. Others, like springtime swimmers, are just putting tentative toes in the water. On one thing everyone agrees — the gas is there; so what's the problem?

Location, location, location

The top three factors affecting any business venture are just as true in the wilds of northeastern BC as they are anyplace. However, whereas in most cases the traditional mantra applies to customer access, at Horn River it applies to product egress. The enthusiasm of tapping a world-class shale gas play is being tempered by the realities of producing, transporting, and processing millions of cubic feet of natural gas and delivering them cost-effectively to southern markets. Some of the early players have been able to access low-pressure gas lines that happened to cross their acreage, and several have negotiated processing capacity at the Missile or Ft. Nelson gas plants. Longer term, plans have been formulated to expand both those facilities in the future. Just like NASA's pilots, operators are more concerned with the landing site than the launch pad.

Pads that promise profits

At Horn River, the "launch pads" vary from football field-sized drilling sites only accessible by helicopter-transportable modular rigs to 2.7 sq mile (6.9 sq km) behemoths with all-weather access roads and capable of accommodating 28 well sites each. The latter are in plans revealed by the Apache/Encana joint venture, by far the largest leaseholders in terms of acreage. According to projections, each pad is expected to deliver a cumulative 150 Bcf of gas from wells producing between 80 MMcfg/d and 100 MMcfg/d in their first year of production. To achieve that scale recovery, Apache Canada President John Crumm presented a comprehensive development concept for each pad consisting of four groups of seven parallel wells placed 820 ft (250 m) apart, each with 5,400-ft (1,646-m) lateral sections in the play. One group would go northwest and target the 320-ft-thick (97.6-m) Muskwa Shale lying at about 8,000-ft (2,439-m) true vertical depth, while the second group would go southeast at the same level. The other two well groups would follow the same pattern except they would tap the deeper, 150-ft-thick (45.7-m) Klua-Evie Shale at about 8,800 ft (2,683 m) in depth. The two shales are separated by a 60-ft (18.3-m) carbonate bed that forms a hydraulic seal (Figure 1).

The aggressive development concept was encouraged by early success on test wells drilled to evaluate play potential. Apache described one well in which a 10-stage frac program was run at 500-ft (152-m) intervals, and which resulted in initial production of 7.3 MMcfg/d for an estimated ultimate potential of 7.6 Bcf. At last report, the Apache/Encana joint venture held a combined 481,625 acres under lease in the Horn River Basin. During 2008, the companies tested their plan in two areas: Dilly and Two-Island Lake. At Dilly, four Muskwa wells were drilled. Three were fracture stimulated using six stages each and the fourth well was used to deploy a microseismic fracture mapping tool string on wireline. At Two-Island Lake, both the Muskwa and the Klua-Evie shales were drilled; the Muskwa well was treated with a 10-stage frac job while the deeper Klua/Evie well was stimulated with a four-stage frac treatment. A third Muskwa well was drilled from another pad and treated with eight stages. All produced gas was transported by a six-in. pipeline to the companies' Missile gas plant about 10 miles (16 km) away. The lessons learned from these tests helped solidify the companies' future development plans.

Production characteristics complicate cash flow

Like most shale gas wells, initial production is high, varying from 2.5 MMcfg/d to as much as 4.9 MMcfg/d. But production quickly tapers off to about 2.0 MMcfg/d within the first two years. After that, steady declines are expected to 200 Mcfg/d for the following 18 years. This presents a problem in properly sizing the infrastructure — pipelines and processing plants. Presently, companies are crunching the numbers to reveal the most economic strategy for the long term. The big Apache/Encana pads are expected to cost about US $220 million each to construct, drill, complete, and tie-in. This year, the company expects to drill and complete a total of 40 wells on the play, which will cost an estimated $348 million, including tie-in to the Missile gas plant. A second phase, which includes compression, dehydration, water systems, pads, roads, facilities, and another gas plant will take a gross additional expenditure of some $212 million. That's the bad news.

The good news is that if everything goes according to plan, net reserves will amount to 75 Bcf of gas from the 2009 campaign at a finding cost of $2.05/Mcf. At a $5/Mcf commodity price, this would yield a modest profit, but a good deal of the infrastructure development is a one-time cost. This, coupled with even a small bounce-back in prices, could precipitate very handsome returns in subsequent years.

The long-range picture is a bit more complicated. Northeastern BC leases are good for four years. But the period can be extended in a variety of ways. Just drilling wells adds more time, and drilling horizontal wells even extends that. Apache figures it can hold the leases by drilling only 14 wells this year, and if it drills 110 wells over the next 10 years it will be able to hold all its acreage by production.

Tough country

Devon Canada's Chris Seasons zeroed-in on one of the principle factors facing Horn River players.

"We're not drilling on the outskirts of Dallas," he said. "We're drilling up in the bush." Seasons contrasted the significant differences in infrastructure and access to markets between Barnett players and erstwhile Horn River pioneers. He also alluded to a seasonal challenge familiar to all Canadians but virtually unknown in Texas — breakup. Each spring, as millions of acres of muskeg start to thaw, roads accessing leases become an impassible morass. If muddy conditions were the only issue, it could be solved with bulldozers, but tracked vehicles would do irreparable permanent damage to the fragile ecosystem of the near-Arctic. Even trucks are prohibited on the existing roads because of the damage they do to thawing blacktop. The problem reached national proportions many years ago, and most Canadian provinces (as well as many northern US states) have enacted "frost-laws" restricting road traffic during the thaw. The issue is so all-pervasive that many Canadian companies simply shut down operations during breakup and put their employees on vacation, suggesting a trip to sunnier climes.

But stopping work is uncharacteristic for the oil industry, and many hours have been spent trying to figure out how to circumvent the breakup while preserving the environment and roadways. In 2007, Nabors Canada introduced its state-of-the-art heli-portable programmable AC electric (PACE) drilling systems. Designed with a mini-footprint, lightweight transportable modules, and arctic weather heating sheds, the PACE rigs have been an instant hit in Canada. Presently five of the units are working in Western Canada. Four are arctic bootstrap triple rigs capable of drilling to 14,765 ft (4,500 m); deep enough to handle any Muskwa horizontal well and all but the deepest Klua-Evie laterals.

To prove that the PACE rigs posed a practical solution for the break-up delay, Nabors decided to mobilize one of its heli-portable rigs to a remote site operated by Ramshorn Investments, a Nabors subsidiary. Picking up the modules one by one, a giant Russian Mi26T helicopter with a 20-long ton payload capacity flew the rig almost 10 miles (15 km) from a staging area on the Laird Highway to a mini pad in the bush. The move cost

Conceptual Shale Gas Development Model

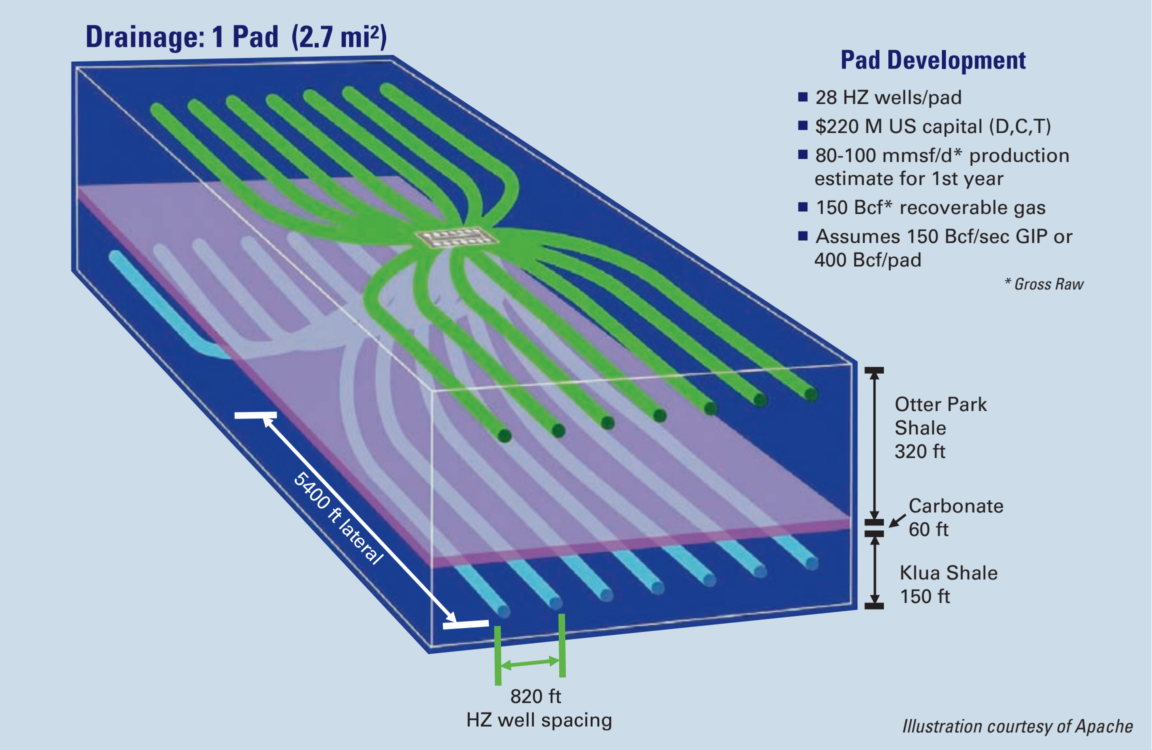


Figure 1. Apache's concept for efficient development of the Muskwa and Klua-Evie shales from huge multiwell drilling pads includes 28 evenly spaced parallel well bores on two levels.

Figure 2. The world's largest-capacity helicopter, the Russian Mi26T, easily transports Nabors Drilling PACE modular electric drilling rig to a remote site in Northeast British Columbia.

$1.96 million, but proved that, if necessary, operations could continue unabated by the frost laws (Figure 2).

Other players proceed cautiously

Public statements by a gaggle of large and small independents describe a mosaic of attitudes. Generally players are optimistic about the potential of the play, but for the most part are proceeding with caution. There is a black hole of information, largely blamed on the unprecedented move on the part of the British Columbia government to grant a five-year immunity from filing well information with the Oil and Gas Commission. The idea is to give players the opportunity to gather information over several drilling seasons to solidify their position before their findings are made public. There is logic behind this move, but there is also a downside. The service companies depend on detailed formation knowledge from which they develop scientific development drilling, completion, and stimulation recommendations. Without this information, they are feeling their way in the dark.

A toe in the water

Storm Exploration is using its experience in the Montney as well as the Cabin, Kotcho, and Junior areas to try its luck at Horn River. The company feels confident to try the Muskwa and Otter Park targets, but lacks enough information to try a deeper Evie test.

Lucky at Lucy

Cognizant of the risks associated with entering a remote play devoid of detailed information, some of the players have formed consortia to share information and thereby moderate the risk. Companies like Trivello Energy and Kodiak Energy are working a project together in the Lucy area of Horn River. They drilled and fraced a vertical well and tied into a low-pressure gas line that conveniently ran through their property. They are also planning to construct a lateral from an existing vertical well to tap both the Muskwa and Evie shales.

Thumping the melon

Similarly, Seven Generations Energy teamed with Result Energy at Dilly Creek to test a highly prospective area east of properties controlled by EOG Resources, Devon Energy, and Nexen. Not satisfied to proceed using "closeology," the team plans to shoot seismic prior to putting a bit in the ground to drill four horizontal wells. Based on the results, they will follow up with another four-well project in 2010 and a six-well project in 2011.

Crew's control

Crew Energy is taking a controlled approach. The company purchased production in 2007 to establish a foothold in the Muskwa and provide some cash flow while it proceeds slowly to develop prospects in the area. In the wings, however, are some fairly big plans involving multiwell pad development should the company make a strike. The plans appear to call for an initial foray into the Muskwa, followed by a deeper thrust from the same pad to contact the Evie. In the meantime, Crew will continue to develop its position in the nearby Montney play.

Sitting pretty with three 6s

EOG Resources, Quicksilver Resources, and Nexen are sitting pretty with a combined 410,423 Horn

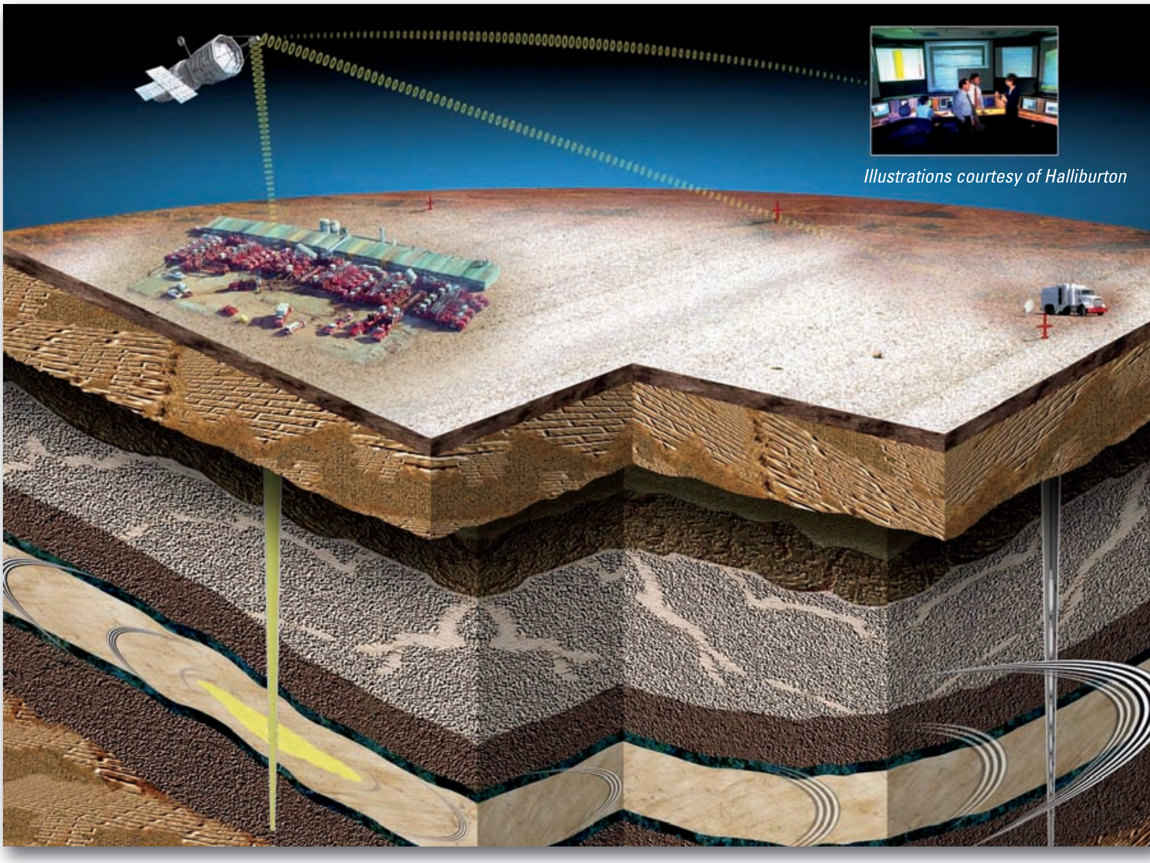


Figure 3. A seismic sensor array in an offset well picks up microseisms from the fracturing process and transmits them in real-time to map fracture propagation.

River acres under lease. All three companies are pursuing aggressive drilling programs showing good results. At the end of 2008, EOG boasted eight horizontal wells with seven flowing to sales, having tapped into an existing pipeline. Potential Muskwa reserves were estimated at 6 Tcf. Quicksilver also estimates its reserves potential at 6 Tcf. Lying within spitting distance of Nexen's, Apache's, and Devon's combined reserves estimated between 20 Tcf and 30 Tcf , Quicksilver put two rigs to work in 2008 to target the Muskwa and Evie shales while building permanent roads and pipelines into its area. Nexen, also claiming 6 Tcf in potential Horn River reserves, is proceeding on all fronts, planning to drill and test multiple wells from a single pad while building infrastructure to sustain production in 2009. A spirit of cooperation pervades. "We are encouraged by the manner in which Horn River development is progressing," said Marvin Romanow, Nexen's president and chief executive officer. "By working together with our peers on the construction of roads, pipelines, and processing facilities, we are achieving economies of scale and reducing our environmental footprint."

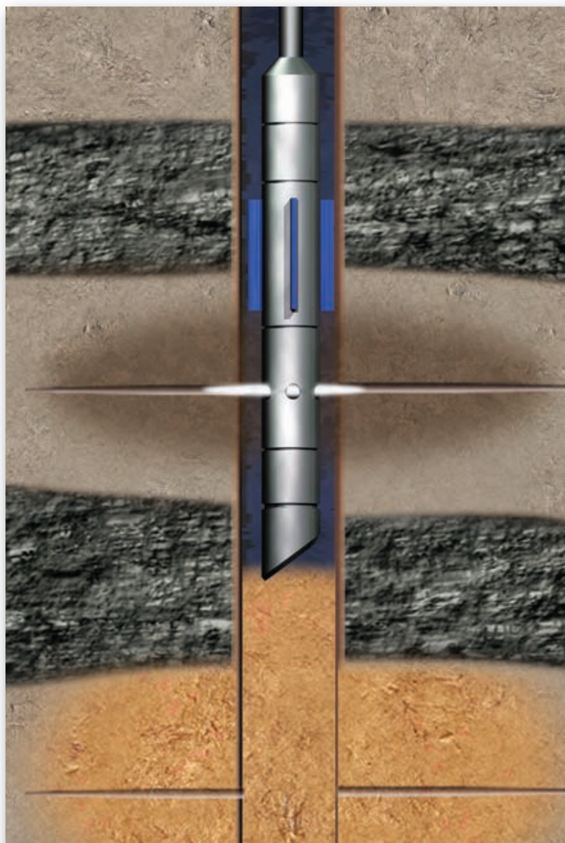


Figure 4. Pinpoint fracture initiation using an abrasive jet is followed by high-rate, high-volume frac fluid pumped down the CT/casing annulus. A sand plug protects previously treated zones.

Watching and waiting

While acknowledging the Horn River play's impressive potential, Petro-Canada and Canadian National Resources Ltd. (CNR) are watching and waiting. CNR has no Muskwa wells, but claims they are in its plans, scheduled to launch in 2010. As for Petro-Canada, the company is focused on international opportunities, and Horn River doesn't appear on its list of hot prospects. The company holds acreage in the Cordova, Montney, and Yoyo areas and has drilled a couple of pilot holes.

Solutions are scarce

There are no easy answers. Developing shale plays can be problematic, no matter where they are. For every claim that the Horn River play is "just like the Barnett," there are two that assert the Horn River is unique. Each major task — drilling, formation evaluation, cementing, stimulating, and completing — requires careful analysis before service providers can make appropriate recommendations with confidence. "It's all about learning," said Brad Rieb of BJ Services. "The best way to approach the task is to invest in information gathering, and if you do, it will pay off in the long run. BJ Services is so convinced of this it has trademarked its 'Understand the Reservoir First' process to emphasize our commitment to base recommendations on science, not guesswork."

But information is scarce at Horn River. Because of the provincial moratorium on well reporting, players are understandably close-lipped about details of their discoveries. Nevertheless, at some point it will be necessary for operators to take service providers into their confidence so cost-effective solutions can be designed. The history of shale development has followed similar paths in each play so far. First, data is gathered, then it is processed and turned into useful information to guide project development. Finally, solutions are proposed and implemented, leading to experience that is used to fine-tune designs and optimize value.

Halliburton's Mike Exner provided a typical example of the Horn River dilemma. "Since most of the producing wells will be horizontal, an ideal solution would be the application of foamed cement technology," he said. "This allows for maximum borehole cleaning capacity and cement coverage on the high side and the low side of the lateral well bore while inhibiting gas migration and minimizing lost circulation."

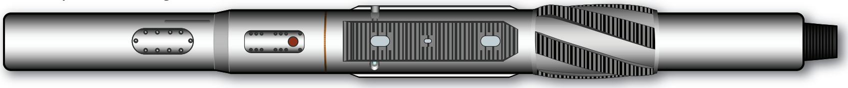
Exner went on to describe a typical Horn River cement job. Halliburton uses tuned spacer systems that are engineered to ensure proper hole cleaning. In addition, tests on the mud/spacer systems are performed routinely to ensure that the pumped fluids are fully compatible with the mud systems. This is even more crucial when oil-based or invert muds are used during drilling. To be sure that boreholes are clean prior to pumping cement, it is recommended to circulate two bottoms-up if conditions permit. Compensation can be made by modifying the designed spacer properties if circulating two bottoms-up is not a possibility.

Slurry yield points and plastic viscosities should correspond to the mud and spacer values. Typically, viscosities are less than 20 cp and fluid loss is less than 15 cc/30 min., depending on the type of mud used in the well and its properties.

Desired spacers are designed to have 1,000-ft (300-m) annular height and are tested for compatibility with the mud prior to pumping. Pump rates are maximized according to the allowable equivalent circulating density. Slurry design commonly considers thickening time (pumping time), fluid loss, free water, rheology, density, and compressive strength development. The main objective is to optimize the cement's ability to prevent annular gas flow and to ensure there is no free water that might contribute to zonal communication.

"Simulation runs performed using software programs such as OptiCem and Displace 3D help ensure optimized hydraulics, and therefore optimized placement of cement slurry," Exner said. Halliburton depends on its extensive field experience in conjunction with best cementing practices to help reduce high cement tops inside the casing after the plug has landed. As an example, employing double HWE or OMEGA cementing plugs in tandem has proved to be very effective in eliminating the high top of cement inside casing. One of the well-known challenges of cementing lateral gas wells is channeling along the top side of the casing/borehole annulus. By applying fit-for-purpose solutions and optimal placement methods, it is possible to effectively eliminate this problem, Exner said.

Courtesy of Baker Hughes INTEQ



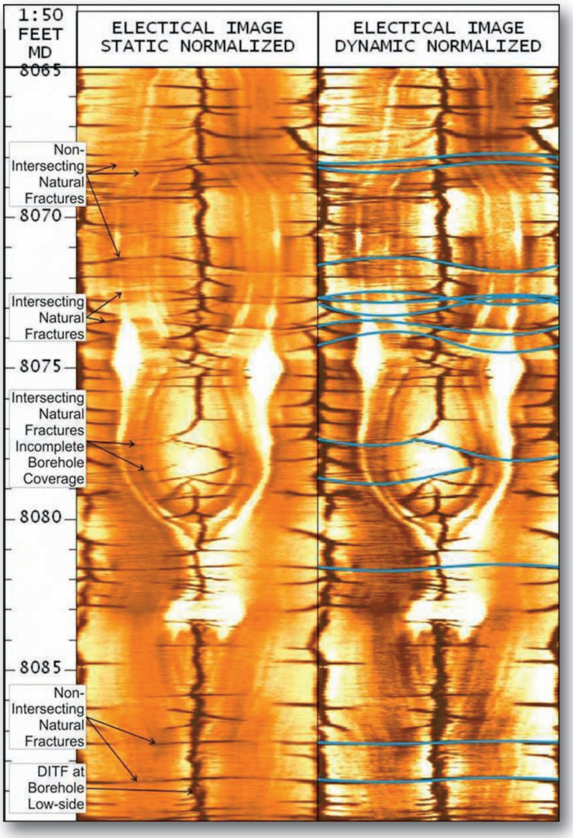


Figure 6. StarTrak imager (left) and StarTrak LWD tool (above) provide a 360º resistivity scan of the borehole while drilling to help in stimulation design.

Stimulation success

Despite a dearth of detailed information, pumping services companies have experienced success in stimulating the few horizontal wells that have been drilled to date. Both Halliburton and BJ Services report that their multizone treatments deployed on coiled tubing (CT) have provided good results. Either treatment can be used in conjunction with microseismic fracture mapping to add flexibility to the process (Figure 3). The microseismic mapping technology allows the pumping services company to observe frac propagation in real time so subsequent frac stages can be optimized.

Halliburton's CT deployment technique involves pumping an abrasive-laden fluid down the CT and out through a jet to initiate the fracture at a precise predetermined depth. The high-pressure jet can cut easily through casing and the cement sheath to initiate the fracture in the formation. It can be used in openhole completions as well. Once the fracture is initiated, the treatment is pumped at high rate down the CT/casing annulus to propagate the fracture and achieve maximum length and wing height. Following each frac stage, a proppant pack is pumped to create a sand plug at the site; then the CT is pulled up to the level of the next stage and the process is repeated. The sand plugs effectively prevent the treatment from entering the previously treated frac. After all stages have been treated, the CT is used to wash out the plugs and clean up the well. Halliburton's patented CobraMax H service is specially designed for deployment via CT in horizontal wells with cemented casing (Figure 4).

BJ Services offers a differing technique with its OptiFrac SJ treatment, which can be run with sand plugs or with a resettable SureSet packer. This CT-deployed technique also pumps an abrasive fluid down the CT to create perforations through the casing and cement sheath. Once the perforations are created, the treatment is pumped at a high rate down the CT/casing annulus. Recently, BJ Services announced the successful setting of its 300th LitePlug system in Canada. The company says that more than 85% of the plugs have been placed in conjunction with horizontal shale well treatments. Ideally compatible with the OptiFrac technique, LitePlug systems are made from a composite of common proppant and BJ Services' LiteProp ultralightweight proppant particles that resist gravity slumping. Principle benefits of the system include improved stability in horizontal cased wells and the ability to hold up to 11,000 psi (80 MPa) of bottomhole pressure, plus rapid clean up properties. According to the company, the system offers greater speed and flexibility compared to mechanical isolation techniques as well as lower risk.

"Risk is greatly reduced when LitePlug is used," Rieb said. "It gives all the flexibility of the Plug 'n Perf fracturing technique without the problem of premature bridge plug setting or extensive post-frac milling and clean-up operations."

BJ's Keri Yule summarized the current situation at Horn River: "The Muskwa Shale play is the newest of the new, and there is not much information available with which to characterize it." She added there is a universal need to properly characterize the reservoir and perform petrophysical analyses on it, as well as obtain knowledge of its geomechanical properties. "Even between wells in the same area of the field there is variability," Yule said.

"What has been reported in the press amounts to the hopes and dreams of the players," Rieb added. "There is no doubt the gas is there, but figuring out the best way to produce it is another thing altogether. With the right science applied in the right places, this problem will be resolved."

Information is key

Companies like Baker Hughes INTEQ may hold the key to the information vault with sophisticated logging-while-drilling (LWD) tools and techniques, especially valuable in precisely placing laterals within reservoir "sweet spots." But equally important is drilling efficiency and hole quality. INTEQ's Darren Drake explained that the Horn River Basin has experienced significant post-depositional uplift that creates challenging drilling conditions, not unlike those the company has experienced in the foothills area of neighboring Alberta. "We see several places where we can provide advantages," Drake said. "The uplift features impact the ability to drill a vertical hole, and our VertiTrak automated vertical drilling system automatically corrects for even slight deviations from vertical while drilling." Drake pointed out that the result is a smooth bore vertical hole with minimal drag that will be beneficial to construction of the critical build and lateral sections.

Another solution for tough drilling is to follow the vertical drilling system with the AutoTrak rotary steerable system for the build and lateral sections. According to the company, this will ensure better placement of the well trajectory within the reservoir with excellent borehole quality. When coupled with a powerful Xtreme modular motor, this will allow drilling efficiency and bit life to be optimized. "Not only do the Xtreme motors provide high torque and heat resistance, but the system as a whole offers the opportunity to control destructive vibration of the bottomhole assembly," Drake added. He explained that the contoured steel stator of the motor helps conduct heat away from the thin rubber elastomer, preventing the heat buildup that causes normal rubber stators to deteriorate.

"We know that the Horn River shales are characterized by swarms of natural fractures," Drake said. "We hope to be able to image these using our StarTrak LWD imaging system." Knowing the location and description of these natural fractures will benefit the engineers who design hydraulic fracturing treatments.

Presently, Baker Hughes INTEQ has designated a Horn River solutions team. As more information becomes available from the operators, the team is building a portfolio of solutions complete with business cases so operators will be able to perform cost/value analyses to economically justify their plans. But, Drake cautioned, "We must have the opportunity to acquire some learnings through iteration before we can be sure of our recommendations, as the life of the field is in its infancy. Ultimately, empirical data supersedes modeling."

Technology not lacking

Service providers are all confident that they have the technical ability to support development of the Horn River Basin. They have the know-how — all they need is the knowledge.

Figure 5. Coiled tubing units efficiently and precisely position multiple frac stages in the well bore. After initiating each frac with a high-pressure abrasive jet, they propagate it by pumping high-volume frac fluid down the annulus, then isolate the stage using LitePlug granular plugs before moving to the next stage.

Photo courtesy of BJ Services

Horn River Activity Spurs New Pipeline Plans

Operators are developing plans for new transportation systems that will move shale gas to Canadian, American, and international markets.

By Bruce Beaubouef, Ph.D.
Editor, *PipeLine and Gas Technology*

The race to move natural gas from the Horn River Basin in Northeast British Columbia is heating up, as EnCana, Spectra Energy, TransCanada, and Pacific Trails Pipelines Ltd. have all announced plans to build new pipeline systems to move the gas to market.

The move to build new pipelines and expand existing systems comes as producers and other operators have stepped up their exploration and development activities in the region. Several industry observers have compared the Muskwa Shale gas in the Horn River Basin favorably with the Barnett Shale gas fields currently being developed in Texas and Oklahoma, where production has surged to more than 3 billion cf/d. Companies operating in the Horn River region – including EnCana Corp., EOG Resources Inc., Nexen Inc., and others – have reported finding trillions of cubic feet of gas under their properties, ranking the discoveries among Canada's largest. Other pipeline firms are also moving to establish a foothold in the region.

Calgary-based EnCana Corp. is one of the leading players in the Horn River Basin. It discovered the natural gas field north of Fort Nelson in 2003 and has since added extensive holdings to become the largest landholder in the area. EnCana recently announced the most precise figure yet on the vast potential of Horn River, saying that it could eventually produce 1 Bcf/d – enough gas to heat 5 million Canadian homes for a year and the equivalent of about 170,000 bbl of oil, bigger than most oil sands mines.

But getting the gas to customers from Horn River, which is adjacent to the southeastern Northwest Territories, requires significant work beyond drilling successful wells. The area north of Fort Nelson is a remote region, where infrastructure such as roads barely exists; access by vehicle is often restricted only to winters when the muskeg is frozen; and key pieces of the puzzle such as pipelines and gas processing plants need to be built or expanded. "Very fundamental basic infrastructure needs to be put in place," EnCana Chief Executive Officer Randy Eresman recently told reporters at an industry investment conference. "That's going to control the pace of that development."

The province is currently working with companies to determine how best to build in the region, while trying to control costs, protect the environment, and deal with concerns of aboriginals. "What usually happens in a hot play is everybody's going in their own direction," said British Columbia Energy Minister Richard Neufeld. "Invariably, a lot of things happen that don't have to happen if there's some planning." EnCana has not said when it could reach its production goal at Horn River, but competitor EOG Resources Inc. of Houston has said it could take three years before major gas production commences in the area.

Nevertheless, EnCana is moving forward its plans for development in the region. In 2007, it formed a joint venture with Apache Corp., and together they have drilled nine production wells in what has become the largest shale gas field in Canada. Now, at a cost of about US $340 million, EnCana said it is moving forward with plans to build an approximately 96-mile (154-km), 36-in. pipeline that will move the gas to existing systems, which will then deliver it to the


Photo courtesy of TransCanada

Pipeline operating companies are developing plans to build new transportation systems that will move Horn River Shale gas to Canadian, American, and international markets.

market. The new pipeline will transport sweet natural gas from the basin to a tie-in point on TransCanada's existing Alberta pipeline system. Subject to regulatory approval, EnCana is planning on a second-quarter 2011 in-service date for the new pipeline system.

Continental Markets

But producers and pipeline companies hope to move the gas not only to local residential customers, industrial consumers and utilities, but also to markets far away, across the continent. To do this, still more pipeline infrastructure will be needed. A key issue here is the pipeline capacity to move the gas, and, of course, the related cost to build and expand these pipeline systems. Peters & Co., a Calgary energy brokerage, recently predicted there could be a pipeline "bottleneck" if plays in northeastern British Columbia, including Horn River and another to the south, are fully developed. Alliance Pipeline Inc., which operates at its maximum 1.6 billion cf/d capacity, connects Fort St. John, south of Fort Nelson, with the Chicago area. Alliance President Murray Birch said pipeline companies will adjust as new gas production emerges.

Spectra Energy is another key player in the Horn River region. Back in March, it announced it had received sufficient support from producers to move forward with plans for an expansion of its existing pipeline system that serves the Horn River Shale gas region. The company said seven producers in the gas-rich region near Fort Nelson have committed to ship 760 MMcf/d on a revamped gathering and processing system. Work on the system would begin later this year and wrap up in 2012. This work will include bringing Spectra's Fort Nelson gas processing plant back to full capacity, adding capacity to its current system and boosting the size of compressors that push gas along the lines. Duane Rae, Spectra's vice president of field services, said a phased approach to expansion could see the addition of as much as 830 million cf/d of incremental expansion capacity. Dollar values were not disclosed, but the Calgary Herald reported that Rae described the move as a "substantial investment" in infrastructure in the area. The company is in discussion with other producers to further increase the capacity of the facility. "The first order of business is to fill up the Fort Nelson gas plant," he said. "There is a need for a substantial amount of both processing and transportation capacity."

TransCanada Corp. has also announced plans for a new pipeline that would move Horn River gas to Edmonton and US markets. The company said it has secured support for firm transportation contracts of 378 MMcf/d to connect new shale gas supply in the Horn River Basin to its Alberta System. The Horn River pipeline will run approximately 96 miles (154 km) with 36-in. pipe, and make use of an existing pipeline in the area to transport sweet natural gas from the Horn River area to a tie-in point on TransCanada's existing Alberta System. The pipeline is expected to be operational early in the second quarter of 2011, subject to regulatory approvals.

TransCanada said it is also encouraged by strong commercial support it has received for the developing shale gas reserves in the Montney formation of northeast BC, as it has recently concluded a successful binding open season for gas transmission service from the Groundbirch area located west of Dawson Creek. Shippers have committed to firm gas transportation contracts that will reach 1.1 billion cf/d by 2014. The proposed Groundbirch pipeline will be approximately 48 miles (77 km) in length, and it is expected to commence service in fourth quarter 2010, subject to regulatory approvals. The project is expected to cost approximately $250 million. TransCanada expects to seek regulatory approval to build both the Horn River and Groundbirch projects as integrated extensions of the Alberta System.

LNG markets

In addition to these projects, the government of British Columbia has announced that it will work closely with local aboriginal groups to secure a direct interest in the Pacific Trail Pipelines Limited Partnership (PTP). The PTP is developing the proposed Summit Lake to Kitimat project, which calls for construction of a $1.2 billion, 288-mile (463-km) natural gas pipeline. When completed, the pipeline will take shale gas from Horn River for export on liquefied natural gas tankers to markets in Japan, China, South Korea, and elsewhere. Both the terminal and the pipeline have received the required provincial and federal environmental assessment approvals and are now working to finalize commercial arrangements.

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BC Offers Development Incentives

British Columbia program encourages road and pipeline development that would facilitate and/or sustain new oil and gas exploration.

By William J. Pike
Editor in Chief, *E&P*

The Horn River Shale gas play is in the early stages of development. Still, the potential is so rich that the government of British Colombia has instituted a significant shale gas development stimulus package. The Infrastructure Royalty Credit Program 2009, administered by the Policy and Royalty Branch (PAR) of the Ministry of Energy, Mines, and Petroleum Resources, encourages road and pipeline development that would facilitate and/or sustain new oil and gas exploration in British Columbia. One of the primary objectives of the stimulus plan is to provide access and infrastructure for future oil and gas developments and to extend the drilling season to allow for year-round activity. Recipients of a grant for a pipeline or road construction or upgrade may receive up to 50% reimbursement of the lesser of estimated or actual cost of construction or upgrade should they qualify for a grant. Applicants will be required to fund the full cost of an approved eligible project prior to any reimbursement.

A contractor/owner must meet established criteria leading to the designation of a Petroleum Development Road (PDR) to be eligible for a road building/upgrade grant. Most importantly, to be classed a PDR the road must meet the all-season standard that requires the road to support vehicle and equipment weights associated with oil and gas activity performed outside the traditional winter drilling season that typically runs from Dec. 1 to March 31. According to the PAR, an all-season road will be open in adverse weather with reasonable maintenance. However, it may be affected by rain, snow, or thaw and subject to seasonal weight restrictions. A further qualification is that the road must not be completed prior to the release date of the Request for Application (RFA).

To meet the grant criteria for a pipeline, a contractor/owner must construct a pipeline or pipeline grid for the conveyance of oil, natural gas, or water that is used specifically in upstream drilling and production operations. Commercial gas distribution lines are not eligible for Infrastructure Royalty Credit funds. Additionally, the pipeline project must be authorized by the Oil and Gas Commission/National Energy Board and must not be completed prior to the release date of the RFA.

Since 2004, BC's Infrastructure Royalty Credit Program has allocated over CAD $315 million in infrastructure royalty credits to oil and gas companies, resulting in 72 new road-based projects and 53 new pipeline projects. Since its inception, the programs have delivered three separate $30 million road installments, a $36.5 million pipeline installment, and a $90 million combined road and pipeline installment.

In 2008, a $100 million road and pipeline installment was approved. The pipeline and road programs have been so successful that the province has allocated $120 million for similar programs in this funding round.

Government Take

One of the notable features of the Horn River development is an unusual level of cooperation among competing firms. The impetus for that came from provincial regulators.

"Because this area was so remote, lacked previous development, and activity was starting at the same time, we saw an opportunity to model the way things could be done," said Vic Levson, Victoria-based executive director, resource development and geoscience branch, British Columbia Ministry of Energy, Mines, and Petroleum Resources.

"From the very beginning we have been encouraging companies to work together, and formation of the Horn River Producers Group was encouraged and facilitated by the province."

Indeed, the level of cooperation and regional planning is unique. The Horn River Producers Group consists of 11 companies that are involved in regional land-use planning, operations coordination, and regulatory development. "It's not perfect, but it's been very rewarding so see the way the basin is being developed," Levson said.

The BC government also gets its own high marks from producers for its fiscal regime. "From the government perspective, we've done a couple of things to help out in the current conditions," he said.

BC introduced a net-profits royalty plan, and the Horn River Basin will be the first application. The royalty is designed for high-risk plays that require considerable up-front capital. There are three tiers of royalties: a low initial royalty of 2% is levied until payout of infrastructure development, and then an intermediate 15% royalty is paid. At three times payout, it settles at 30%.

"This way, the government shares the upfront risk in development in a new resource play in a brand new basin," Levson said.

Another provincial initiative is an infrastructure royalty credit, in which the government credits up to half the cost of new road and pipeline development. One criterion is whether a project will increase incremental revenue to the province.

"We are a competitive jurisdiction and, in this downturn, other provinces in Canada have seen a much steeper decline in drilling than we're seeing in BC," added Levson.

Mike Graham, executive vice president of Calgary-based EnCana Corp., agreed. "We give a lot of credit to the BC government. Without them, the Horn River and the Montney plays wouldn't be there."

— *Peggy Williams,* Oil and Gas Investor

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For more details on the Muskwa Shale/Horn River Basin in British Columbia, Canada, consult the selected sources below.

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