

---

SOURCE: OIL & GAS INQUIRER

## Superplays

# Montney and Horn River: Two Superplays Drive Drilling And Technology

By Mike Byfield

In northeastern British Columbia, producers continue to make record-shattering land purchases in the Horn River and Montney unconventional gas plays-massive prospects that will reshape Canada's petroleum sector if they pan out as hoped. B.C. Minister of Energy, Mines and Petroleum Resources Richard Neufeld comments, "At the most recent Crown auctions, the payments per hectare have been as remarkable as the total revenue. The resource potential is enormous, the early wells are giving good results, and we're drawing a strong mix of producers. It all tells me there's a great future here."

As an oil and gas service sector veteran himself, Neufeld knows that large-scale field activity normally follows large-scale land investment, and British Columbia's take from land sales has indeed been large. The Crown took in \$630 million in 2006, \$1.05 billion in 2007, and \$2.1 billion during the first eight months of this year. Per hectare, bids have averaged almost \$4,000 to date in 2008, up from \$1,060 in 2007. Alberta, Canada's former heavyweight in terms of land sales, took in just \$745 million between January and August, while red-hot Saskatchewan received \$848 million.

B.C.'s seductive new energy star is tight gas, especially shale. The world's most common sedimentary rock, shale is typically rich in methane-generating organic carbon but it's also dogged by ultra-low permeability. The Horn River Basin, in the far northeastern corner of the province, is a pure shale gas reservoir. The Cordova Embayment is a geologically similar extension in the same region. Further south sits the Montney play, a blend of low-permeability sandstone, siltstone, and shale intervals which sprawls across Peace River farmlands to the foothills well to the west of Fort St. John. The lower horizons within the Montney have more shale.

Although difficult to exploit, tight gas resources are huge. The Illinois-based Gas Technology Institute estimates that gas-in-place within U.S. shales ranges from 500-780 Tcf, with a reasonable recoverability target of perhaps 20 per cent. Neufeld cites provincial government studies that peg B.C.'s shale gas potential between 250 Tcf and 1,000 Tcf, with an unknown recoverability factor.

Commercially successful shale development dates back to the late 1990s. In the Fort Worth area of Texas, a junior producer (Mitchell Energy, acquired by Devon Energy in 2002) combined horizontal drilling and improved hydraulic fracturing techniques to literally crack open the Barnett shale formation. Nicknamed the "king of shales" and considered by many to be the largest onshore gas field in the U.S., the Barnett shale is now yielding more than 1 Tcf annually. The gas resource is commonly estimated at 30 Tcf.

In British Columbia, Neufeld was an early and eager student of the growing shale success in Texas. An MLA for Peace River North since 1991, he became energy minister when the Liberals swept the New Democrats from office in 2001. "I've moved rigs, built lease roads, and operated a bulk plant," says the Fort St. John resident, who earlier in his career served as mayor of Fort Nelson for five years. "It's definitely fair to say that I understand the petroleum service sector." The enterprise-friendly politician advocates coal-fired electrical generation and supports scientific evaluation of offshore drilling.



Under his leadership, the new Liberal government conducted pivotal studies of the province's unconventional gas potential, a key factor in drawing producers to northeastern B.C. Equally important were a series of provincial royalty reforms that encouraged exploration and production: a coalbed royalty program (2002); deep, marginal, and summer royalty programs (2003) and; deep re-entry and ultra-marginal royalty programs (2006).

For a technically complex play like the Horn River Basin-whose expense is increased by its remote, rugged location where drilling is restricted to winter-the royalty rate is 2 per cent of gross revenues until capital costs are recovered. The rate then increases by steps to a maximum of 5 per cent of gross revenues or 35 per cent of net profits, whichever is greater. B.C.'s investment-friendly measures became all the more attractive when Alberta Premier Ed Stelmach imposed a tougher royalty regime that's scheduled to take effect in January 2009.

ARC Energy Trust began breaking open the Upper Montney formation in 2003 but development only took off after it drilled the play's first multiple-stage frac horizontal well in July 2005. With a lateral reach of 1,500m and 5 fracs along its length, the pioneering well cost \$7.9 million and is still producing 1.6 MMcf/d. In contrast, ARC recently drilled a 1,900m horizontal leg, fraced it 8 times, spent \$5 million, and achieved initial production of 8 MMcf/d. The company reports finding and development costs of about \$10/boe at Dawson, a netback of about \$40/boe, and total production of about 5 Bcf (nearly one million boe) for each well.

These are enticing numbers. In August, Shell Canada paid \$5.9 billion to acquire Duvernay Oil Corp. Given Duvernay's current output of about 27,000 boe/d, the purchase price amounts to a spectacular \$220,000 per flowing barrel. The real attraction is land and infrastructure. Duvernay owns 450,000 net acres in northeastern B.C. and northwestern Alberta's Deep Basin, virtually all of it characterized by tight gas prospects. It also owns processing facilities in these districts.

Service companies can anticipate more rewards from tight gas in northeastern B.C. Michael Rose, Duvernay's president and CEO, thinks the 80-km Doig formation trend will yield 500 Bcf and the company has already mapped out 200 drilling locations. Even so, Rose said, at Duvernay's annual meeting in June, that the underlying Montney horizons "will dwarf [the Doig] as far as production and drilling inventory is concerned." Altogether, Duvernay has an inventory of 700 potential drilling locations in B.C. and 1,400 in the Alberta portion of the Deep Basin.

Last February, EOG Resources, Inc. pushed the Horn River Basin into the headlines, announcing that it could recover 6 Tcf from the Muskwa formation. EOG, a leading Barnett producer, spotted geological similarities in the Muskwa shale interval, which is 500 ft thick. Over three years, the company assessed the prospect and drilled six wells (three vertical and three horizontal). EOG reports that the gas-filled porosity in a Muskwa well was 4 per cent versus 4.5 per cent in the Barnett formation. The Muskwa well also has better silica content at 65 per cent (versus 55 per cent in the Barnett) which makes for good reservoir quality.

EOG's first two horizontal wells had initial production of 3.5 MMcf/d and 4.2 MMcf/d. Although shale gas wells typically decline heavily within a few years, they will produce steadily at lower levels for decades. The Houston-based company believes the Muskwa could hold twice as much gas per section as the Barnett shale. Energy minister Neufeld points out that prospective gas density on that order has pushed per hectare bids for Crown rights in northeastern B.C. to levels rarely equalled in North America. EOG produced its first sales gas from its Horn River acreage this summer but forecasts that it will take until 2011 to ramp up large-scale volumes.

Shortly after the EOG's dramatic 6 Tcf forecast, Nexen Inc. announced that its Dilly Creek acreage within the Horn River Basin has the potential to produce 3 Tcf to 6 Tcf of shale gas. Days later, Imperial Oil Limited stated that it had acquired 46,500 ha of Horn River acreage in partnership with another subsidiary of Exxon Mobil, the world's largest privately owned petroleum producer. In June, Exxon Mobil told analysts at the Reuters Global Energy Summit in Houston that it plans to invest more heavily in large-scale unconventional gas plays of this type.

In terms of exploration, tight gas is more comparable to oilsands than to conventional oil and gas. "After a modest amount of drilling and assessment, the resource is pretty much known to be there in very large quantities," explains Mike Dawson, president of the Canadian Society for Unconventional Gas (CSUG).

"The challenge is extracting the gas at an economic cost. The fundamental solution to that problem is coming through multiple hydraulic fracturing of long horizontal wellbores."

However, Dawson notes that every major shale formation is geologically distinct. "Techniques that work well in the Barnett provide no more than a starting point for northeastern B.C. A lot of expensive fine-tuning must be done in each area," he says. Ideally, a shale gas producer can drill a handful of wells on its extensive acreage, determine what production methods work best, and proceed to drill dozens, even hundreds, of additional well bores with similar results.

"We don't know yet how consistent the western Canadian tight gas formations are geologically, so only time will tell how extensively a producer will be able to apply the same drilling and completion techniques," Dawson says. "We're still in the early stages of this game but it's tremendously promising." The Montney trend, for example, is more than 300 km long and 280 km wide with varying reservoir characteristics and quality. Its geological variety in turn leads to different production type curves, recoveries, and costs per well.

The first horizontal wells that were multiply stimulated used coiled tubing-conveyed bridge plugs and perforating guns. Each frac was followed by a one- to two-day period in which the well was flowed. The bridge plugs had to be drilled out at each stage. The procedure consumed time, with expensive frac pumping units idling while rig hands tripped in and out of the hole. A switch to pump-down bridge plugs and wireline-conveyed perforating guns created a more continuous operation but the in-casing plugs still had to be removed.

Next came the development of expandable rubber packer systems, such as Halliburton's Swellpacker and StackFrac from Packers Plus Energy Services Inc. This approach enables producers to frac an open hole up to 11 times in a single sequence, starting at the end of the horizontal leg and working back in stages. The savings in time and materials—for instance, the option to stimulate a reservoir without cementing—can be dramatic.

Expanding rubber packers, however, are limited to a maximum pressure of 10,000 psi. Also, their ball-activated control mechanism requires progressively smaller diameters of ball seat at each stage, which limits the total number of stimulation stages in the frac sequence. With horizontal well bores now extending beyond 2,500m in some cases, that restriction becomes a more serious issue.

To meet this type of demand, Halliburton developed CobraMax H service, a procedure performed on horizontal wells with cemented casing. Perforation is achieved with a water-jet bottomhole assembly deployed via coiled tubing. Sand plugs are used to isolate each stage for frac stimulation, which eliminates the need for mechanical plugs. Sequential stimulation can be extended to the maximum reach of the coiled tubing. "With CobraMax H, the number of frac intervals is not limited by mechanical restrictions," says Roch Romanson, a pinpoint stimulation specialist with Halliburton.

In a sober report with a humorous title, Montney Python—The Holy Grail of Canadian Tight Gas, Tristone Capital Inc. projected last March that the Montney play alone could boost capital spending in the upstream petroleum sector by 10-15 per cent within two years. Chris Theal, Tristone's research chief, estimates the Montney resource at 17.6 Tcf but acknowledges that his figure is highly conservative. Even minimal estimates aren't available for the Horn River Muskwa, whose full extent has yet to be delineated.

Spectra Energy, the main midstream operator in the region, has plans to expand its pipeline and processing capacity. However, producers are likely to proceed prudently with contractual commitments. No one has forgotten Ladyfern, another large discovery in northeastern B.C. The initial strike in 2000 triggered a rush of drilling and construction but production unexpectedly peaked in just two years. Cautions Bill Gwozd, vice-president of gas services at Ziff Energy Group: "At the end of the day you have to have proven resources to underpin the pipeline."