

Doig's Digest

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CANADIAN SHALE GAS AFTEREFFECTS

Although drilling for unconventional shale gas was recorded close to two hundred years ago, it wasn't really until approximately 15 years ago that technical successes for this "new" gas started to seriously revise North American supply-demand charts, which had been strongly signaling mid-term conventional natural gas shortages. But in a good news story, the technical efforts of the service sector and production companies have turned gloomy forecasts into sunny ones. Now a continent that had been looking to import large volumes of liquefied natural gas (LNG) to meet its natural gas needs is looking to export excess supply.

Into this fast moving playing field we discuss two recent reports authored by the National Energy Board (NEB) – the Horn River Basin in northeastern British Columbia and Canadian natural gas deliverability issues – that confirms how drastically the Canadian natural gas supply-demand equation has been altered and will stay altered in years to come.

Elsewhere in this month's *Doig's Digest* we also discuss two other aftermaths left from this shale gas explosion. See Page x for the downfall of the Denali – The Alaska Gas Pipeline and the questions surrounding the current status of the Alaska Pipeline Project. Also see Page 7 for the discussion on the Kitimat LNG Project that will be the first Canadian terminal to export LNG to offshore markets.

Horn River Basin

The unconventional natural gas potential from the Horn River Basin in northeastern British Columbia is much bigger than first forecast and will likely become larger as more well data becomes available. That, in summary form, is the findings from a report titled *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin* released in early May. Prepared by the NEB and British Columbia Ministry of Energy and Mines (BC MEM), the report is the first publicly released probability-based resource assessment of a Canadian shale basin.

Potential of 78 Tcf

The report says the ultimate potential (the medium case estimate) for marketable unconventional shale gas in the Horn River Basin is 78 Tcf, including 3 Tcf of discovered resources and 75 Tcf of undiscovered resources. The Horn River Basin is part of the larger Western Canada Sedimentary Basin (WCSB). Placing the Horn River numbers in a broader regional context, the NEB currently estimates that there is 197 Tcf of conventional and unconventional natural gas remaining in the WCSB -- although this number does not take into account known but as-yet-unassessed unconventional gas resources.

The estimate of total remaining conventional and unconventional natural gas in northeast British Columbia available for future demand is 109 Tcf. That includes 78 Tcf of shale gas as well as 31 Tcf of remaining natural gas resources identified in a joint assessment of conventional natural gas resources in the area.

The BC MEM's and the NEB's last complete study of B.C. was of the conventional resource potential and was completed in 2006, based on year-end 2003 data. That report indicated there was additional potential for natural gas in B.C. in unconventional reservoirs, but that there was not enough data to confidently estimate gas resources. Now that data is now starting to become available and, in 2010, the BC MEM and the NEB determined that there was sufficient data to estimate the potential of the Horn River Basin shale gas play.

Once this new data is added to the 2006 estimate for conventional ultimate potential, and accounting for cumulative production to year end 2010 of 21.3 Tcf, the estimate of remaining conventional and unconventional natural gas available for future demands is 109 Tcf. This does not include other unconventional gas resources which are known to exist in B.C.

Impurities vary

Off note, the amount of impurities in Horn River Basin shale gas appears to vary by shale, with some wells as low as eight per cent and others as high as 19 per cent, and consists dominantly of carbon dioxide. The impurities increase with depth.

The only previously published study of resource potential in the Horn River Basin was completed in 2008. At that

time, the gas in place resources of the Horn River Basin, Cordova Embayment, and Liard Basin were estimated to be between 144 Tcf and more than 600 Tcf. However, no attempt to break out the gas resources between basins and no estimate for marketable resources was made. The BC MEM released the results of an internal study in 2009 suggesting the Horn River Basin contained between 300 Tcf and 800 Tcf of GIP.

Northeastern British Columbia now holds about 55 per cent of the reported ultimate remaining conventional and unconventional natural gas resources in the WCSB.

Other plays in B.C.

There are a number of other unconventional natural gas plays in British Columbia and elsewhere in the country, which, if developed, could substantially increase the resources available for Canadian use and export purposes. The agencies intend to assess these B.C. plays as time, data, and resources allow. The NEB also intends to assess unconventional plays elsewhere in the country.

Interestingly, the report also details highlights of the other major Canadian shale gas play – Montney (B.C. only but not containing enough data to assign marketable resources), and the U.S. plays at Barnett, Marcellus, Haynesville and Fayetteville (see table 1, Page x; also see below for production forecasts on the Horn River and Montney plays).

Canadian Natural Gas Deliverability

It comes as no surprise but last month the NEB added its voice to the obvious: current market factors are causing a decline in natural gas deliverability in Canada. Although gas deliverability is forecast to decrease (the mid-range case) from 13.4 Bcf/d in 2011, to 13.2 Bcf/d in 2012 and to 12.8 Bcf/d by the end of 2013, there is still ample supply to meet Canadian needs.

In support of its ongoing market monitoring, the NEB periodically publishes assessments of Canadian supply and demand of energy and natural gas markets. These assessments address various aspects of energy markets in Canada. In its latest report, *Short Term Natural Gas Deliverability 2011-2013*, the Board examines trends for natural gas deliverability in Canada (the ability to produce natural gas from new and existing wells). The two key market factors with the greatest impact are an oversupply of natural gas in both Canada and the U.S. and a shift in drilling away from natural gas towards crude oil and other liquid hydrocarbons to capitalize on higher oil prices.

Table 1
Comparison of North American Shale Gas Basins

	Canada		United States			
	<i>Horn River</i>	<i>Montney (B.C. only)</i>	<i>Barnett</i>	<i>Marcellus</i>	<i>Haynesville</i>	<i>Fayetteville</i>
Basin Area (km ²)	11,500	1,600-10,000	1,900	95,000	9,000	9,000
Depth (m)	1,800-3,000	1,000-3,000	2,000-2,600	2,500-3,000	3,000	350-2,300
Thickness (m)	50-350	50 > 300	15-182	12-275	75	16-180
Reservoir	dry	wet/dry	wet/dry	wet/dry	dry	dry
Gas in Place (tcf)	448	80-700	327	1,500	717	52
Marketable (tcf)	78	Uncertain	44	262	251	42
Production* (approx – MMcf/d)	300	500	–	2,200	–	–
Production* (approx – boe/d)	–	–	880,000	–	700,000	65,000

Source: National Energy Board and British Columbia Ministry of Energy and Mines

"Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin"

* Miscellaneous sources

The deliverability forecast (the mid-range case) is based on the following: 2011, Henry Hub average price (US) \$4.25 per MMBtu, 4033 gas wells drilled, average Canadian natural gas deliverability, 14.4 Bcf/d; 2012, (US) \$4.50 per MMBtu, 3667 gas wells drilled, average Canadian natural gas deliverability, 13.2 Bcf/d; and 2013, (US) \$5.00 per MMBtu, 3375 gas wells drilled, average Canadian natural gas deliverability, 12.8 Bcf/d.

In past years, natural gas accounted for close to 80% of the wells drilled in Canada but now represents only about 40% of the wells drilled during the study period. Also directly affecting Canada is the fact that increased shale gas production in the U.S. allows it to meet more of its internal demand and thus decrease opportunities for Canadian natural gas exports. Although the NEB projects that annual Canadian natural gas demand will grow by 0.6 Bcf/d between 2010 and 2013, most of this increase will be from usage for Alberta oil sands developments.

Will trend downward

Further impacting Canadian deliverability problems are two new U.S. pipelines – the Bison Pipeline and the Ruby Pipeline. These new systems will enable more U.S. domestically produced gas to move to markets traditionally served by Canadian exports. The 487-kilometre, 30-inch Bison Pipeline entered service in January 2011 with an initial capacity of 0.4 Bcf/d to move natural gas from Wyoming into the Northern Border Pipeline that serves the U.S. Midwest. The 1,095-kilometre, 42-inch Ruby Pipeline is scheduled to enter service in June 2011 with a capacity of 1.5 Bcf/d to move natural gas from Wyoming into the Pacific

Northwest and California.

In closing, Canadian natural gas deliverability will trend downward over the period but will be more than adequate to meet Canadian requirements. As drilling decreases in 2012 and 2013, the rate of decline in deliverability slows slightly due to higher productivity wells coming on-stream. Tight gas and shale gas activity will increase in 2012 with 268 wells drilled in the Montney and 82 in Horn River and will continue upwards in 2013. The NEB forecasts that Horn River deliverability will increase from 243 MMcf/d in 2010 to 570 MMcf/d in 2013 and British Columbia's Montney deliverability will go from 476 MMcf/d in 2010 to 1,883 MMcf/d in 2013.

CRUDE OIL PIPELINES – MALFUNCTIONS

To be brutally honest, the past 10 months hasn't been a vintage period for the Canadian crude oil pipeline industry. In fact, the numerous incidents that have occurred since late July 2010 have put wind in the sails of its opponents, especially those opposing the building of TransCanada Corporation's Keystone XL Pipeline and Enbridge Inc.'s Northern Gateway Pipeline. The transportation stoppages have already played on the oil producers' earnings and will play havoc with their second quarter 2011 earnings when they are released in a few months.

In the following, we discuss the troubles encountered by Enbridge Inc. last year with Line 6B, Line 6A and Line 10, all located in the U.S.; by TransCanada's Keystone system, again in the U.S.; by the Enbridge NW system in the Northwest Territories; by Kinder Morgan Canada's Trans Mountain Pipe Line in Alberta; and by Plains Midstream Canada on its Rainbow Pipe Line in Alberta

Troubles all over the place

Enbridge's Line 6B, Line 6A and Line 10

The 10-week period running from late July 2010 wasn't a very good period for the company that runs the world's longest and most complex crude oil pipeline system with a capacity of 2.1 million b/d and which exports 69% of

Western Canadian crude oil exports and fulfills 12% of U.S. crude oil imports.

During that period, three U.S. pipeline systems, operated by Enbridge Inc. of Calgary and its U.S. partners, were shut down for various periods due to pipeline failures. On July 26th, Line 6B, which was built in 1969, was shut down due to a leak near Marshall, Michigan. The 30-inch 190,000 b/d line transports light synthetics, heavy and medium crude from Griffith, Indiana, to Sarnia, Ontario. The leak spilled 19,500 bbls into the Kalamazoo River in central Michigan. It is part of the Enbridge Energy Partners, L.P., Lakehead System.

On September 10th, Line 6A was shut down due to a leak at Romeoville, Illinois. The 34-inch, 670,000 b/d transports light synthetics, heavy and medium crude from Superior, Wisconsin, to Griffith, Indiana. Again, this pipeline is part of the Enbridge Energy Partners Lakehead System. At the time it was shut down, Line 6A was shipping 459,000 b/d. Romeoville is 48 kilometers southwest of Chicago.

Line 6B needs more work

Then, on September 13th, Line 10 was shut down due to a leak near Buffalo, New York. The 70,000 b/d line runs 146 kilometres between Westover, Ontario, and Kiantone, New York.

The accident on Line 10 was minor. It was back up in operation the next day. Line 6A, which recorded a spill of 6,100 bbls was down for seven days. However, Line 6B was out of action for two months (starting up on September 27, 2010). Capital costs associated with this failure were \$175 million and operating costs were \$5 million.

Enbridge will spend \$286 million replacing 121 kilometers of pipe on its troubled Line 6B pipeline, which ruptured last summer, spilling crude oil into a Michigan river system, the company's U.S. affiliate. Enbridge Energy Partners, which controls the U.S. portion of Enbridge's oil pipeline network, said work on replacing portions of the line, which runs 472 kilometers from Griffith, Indiana, to Sarnia, Ontario, will begin in 2012.

TransCanada's Keystone System

On May 7th, TransCanada's Keystone Pipeline spilled approximately 500 bbls of crude oil at one of its pump stations in North Dakota. The cause of this breakdown, which shut the system down for six days, was a valve failure at a pump station approximately 65 kilometers southwest of Milnor. This was the tenth spill that has occurred related to equipment failures at pump stations since the 591,000-b/d system (containing 24 pump stations) commenced operations in June 2010.

However, all these leaks have taken place on TransCanada's property. There have been no leaks from the Keystone system itself that takes heavy oil from northeastern Alberta to Wood River and Patoka, Illinois, and then to Cushing, Oklahoma. But it is incidents like this that give momentum to the opponents of the proposed Keystone XL Pipeline to the U.S. Gulf Coast, which is now under serious review by the U.S. State Department. The Keystone system reopened on May 13, 2011.

Another black mark

Unfortunately, TransCanada had to report more bad news on May 31st. There was another leak of 10 bbls at a pumping station at Severance, Kansas. Although not a lot of oil, it nevertheless leaves another black mark.

Enbridge's NW System

As if things weren't bad enough, Enbridge further announced last month that its 39,400-b/d, 870-kilometer NW

System, completed in 1985, running from Norman Wells, Northwest Territories to Zama, Alberta, where it joins into the Rainbow Pipeline, had also encountered problems. A small spill of oil (believed to be approximately 4 bbls) had occurred south of Wrigley, Northwest Territories. Caught up in both the Enbridge's NW System and Rainbow Pipeline misfortunes is crude oil production at Norman Wells, owned by Imperial Oil Limited.

Kinder Morgan Canada's Trans Mountain Pipe Line

A week before the Rainbow Pipeline incident, Kinder Morgan Canada's 300,000-b/d Trans Mountain Pipe Line running from Edmonton to terminals in the Vancouver area and Washington State sprang a leak 150 kilometers west of Edmonton. Unfortunately, the owner of the land and not the company discovered the leak, which spilled a small amount of crude oil. The system was out of order for a week. This was bad timing for Trans Mountain, which is in the final stages of its 2011 Negotiated Toll Settlement Application for Final Tolls.

Plains Midstream Canada's Rainbow Pipe Line

However, the most serious pipeline malfunction occurred in Alberta on April 28th when the 220,000-b/d Rainbow Pipe Line, operated by Plains Midstream Canada (100%), sprang a leak of 28,000 bbls. The 772-kilometer pipeline consists of two main segments: a 20-inch line running from Zama to the Nipisi terminal where it joins to a 24-inch line running into the Edmonton area. The Rainbow system also contains 183 kilometers of gathering pipelines. Last year, the system transported 187,000 b/d.

Bought asset from Murphy Oil

Ten years ago, Plains All American Pipeline, L.P., a publicly traded master limited partnership headquartered in Houston, entered the Canadian oil industry when it acquired the Canadian crude oil pipeline, and the gathering, storage and terminalling assets of Murphy Oil Company Ltd., as well as the assets of CANPET Energy Group, Inc., a privately held Calgary-based Canadian crude oil and LPG marketing company for (US) \$155 million. These assets, that began operating as Plains Marketing Canada, L.P., now operate under the Plains Midstream Canada banner.

The Rainbow Pipe Line, originally owned by Imperial Oil Limited, Mobil Oil Canada Limited and Shell Canada Limited, commenced operation in 1965 to tie in numerous oil discoveries that had been made in northwestern Alberta during the late 1950s and early 1960s. Shortly after it became the outlet for Banff Oil Ltd.'s 1965 Rainbow Lake oil and gas discovery, which included Aquitaine Company of Canada and Mobil Oil Canada. The Rainbow Pipe Line was sold to Plains Marketing Canada in 2008 for \$540 million.

The Alberta spill occurred on the 20-inch northern portion, north of Nipisi pump station, near the community of Little Buffalo. However, the break wasn't confirmed until 12 hours later. The cause goes back to incorrect repair work that was performed on the system a year earlier.

So 10 years after it entered the Canadian oil scene and 3 years after it purchased the Rainbow Pipe Line, Plains Marketing Canada has recorded the largest oil pipeline spill in Alberta in the last 36 years. In 1975, the Bow River Pipeline Ltd. had a spill of 41,000 bbls.

Largest spill in 36 years

Ironically, at the same time that Plains Midstream Canada was dealing with the clean up of the Rainbow Pipeline, it was also into the advanced stages of preparing to build a new pipeline, Rainbow Pipeline II that would travel much of the same lands as the Rainbow Pipeline. The new 12-inch low vapour system, from the existing Plains Marketing Canada's Nipisi Terminal to Edmonton, will parallel 91% of the same route and will be located within 88% of its existing right-of-way.

The company filed its regulatory applications for this new system in the fall of 2010 and had been expecting a decision in the second quarter of this year. If approved, construction will commence this fall with completion scheduled for a year from now.

This also hasn't been a good run for Plains Midstream Canada's U.S. parent. A year ago, Plains All American Pipeline settled a suit with the U.S. Environmental Protection Agency over 10 oil leaks, which leaked a combined total of 6,510 bbls, found in its system between 2004 and 2007. Out of the agreement, the company spent \$41 million to upgrade sections of its 17,000-kilometre system in the U.S. and also paid a fine of \$3.25 million.

Needs a upgrade

While the Alberta spill exposed a badly reconstructed section of pipe from a year previous, it also exposed a company that was also badly in need of a serious public relations upgrade. Hard to believe but still nevertheless true, it took Plains Midstream Canada four days to inform the public as to what had happened and another three days before the company held its first news conference to give its side of events.

For 17 days, the company was shipping about 100,000 b/d on its 24-inch southern system from the Nipisi station into Edmonton while repair work was underway on the 20-inch northern system. Unfortunately, due to forest fires that engulfed northern Alberta plus the power being cut off, both systems were shut down on May 15th.

On May 25th, 10 days after it had been shut down, the fire evacuation order was lifted and shipments through the 24-inch southern system were restarted. However, at the end of May, the company still hadn't received permission from the Energy Resources Conservation Board to restart the 20-inch Zama line. At the end of May, less than half of the spill had been cleared up.

KITIMAT LNG – A CANADIAN FIRST

A first in Canadian energy regulatory history will commence on June 7th in Kitimat, British Columbia, when the National Energy Board (NEB) commences a liquefied natural gas (LNG) export hearing (GH-1-2010). Open for review will be the application filed by KM LNG Operating General Partnership on December 9, 2010, requesting approval of a licence to export up to 10 million tonnes of LNG per year (or 468 Bcf per year). Participating at this hearing will be 24 intervenors.

During the term of the 20-year Licence being applied for, the quantity of LNG that may be exported shall not exceed 200 million tonnes (or 9,360 Bcf). KM LNG will be the operator of the export terminal to be constructed and operated at Bish Cove, near the port of Kitimat, British Columbia. Apache Canada Ltd. (40%), EOG Resources Canada Inc. (30%) and EnCana Corporation (30%) hold participating interests in this joint venture arrangement.

Also an Asian Pacific first

This is the first time that an export of LNG has been applied for under the present NEB Regulations for the purpose of accessing offshore markets. Gas production will be liquefied at the Kitimat Terminal and directly transported by LNG carriers primarily to Asia Pacific markets, a new, long-term and stable market for Canadian natural gas supply. Another first will be Asian Pacific buyers taking unconventional shale gas.

The terminal location is on the Bees Indian Reserve #6 which has been designated for industrial park use. The

operation of this site for the project has received the support of the Haisla First Nation, and, with that support, KM LNG and the Minister of Indian Affairs and Northern Development (“INAC”) entered into a long-term lease for the Kitimat LNG Terminal on the Bees Indian Reserve #6 in November 2010.

*Decision later
this year*

The Kitimat terminal, to be erected under a partnership arrangement with the Haisla First Nation, will be on-stream in 2015. Current plans call for the initial phase of the terminal to have an annual capacity of approximately 5 million metric tonnes (approximately 700 MMcf/d). As it currently stands, Phase 2 is scheduled to come on-stream in 2018, which will move daily output to the 1,400 MMcf/d level, a volume that many observers now say that it should be starting at. The companies hope to have firm sales commitments in place by the time that a final investment decision is made later this year.

The natural gas will make it to Kitimat through the 36-inch, 463-kilometre Pacific Trail Pipelines running from Summit Lake, British Columbia. Pacific Northern Gas Ltd. will operate and maintain this system under a seven-year agreement with the three companies holding provisions for five-year renewals. The three companies have also agreed to 20-year transportation service agreements to use a portion of Pacific Northern Gas’ current pipeline capacity.

During the hearing, however, the companies (for competitive reasons) will not be revealing details of any long-term contracts that they might already have concluded in an increasingly crowded Pacific Rim market place (see Page 13 for a discussion on Shell’s Australian Floating Liquefied Natural Gas facility).

Coming into play at the tail end of the preamble leading into the hearing was a Notice of Motion filed by the Gitxaala Nation on April 26th, which requested that the KM LNG Partnership’s export application be expanded to include an environmental assessment under the Canadian Environmental Assessment Act. The Gitxaala Nation, consisting of approximately 500 band members, is a First Nations government located at Kitkatla, British Columbia, at the mouth of the Douglas Inlet that leads into Kitimat. In essence, export licences don’t require environmental approvals.

*Bridge has
been crossed*

However, that bridge was crossed five years ago when the proposed LNG facility won approval from both the Federal and Provincial authorities. In April 2006, a Joint Assessment Report and Comprehensive Study Report approved the Kitimat LNG Terminal Project. The B.C. Environmental Assessment Office and the Canadian Environmental Assessment Agency (on behalf of Transport Canada, Environment Canada and Indian and Northern Affairs Canada) prepared this approval.

ALASKAN NATURAL GAS – ONE DOWN

It is no surprise – the North American unconventional shale gas explosion that has been underway for the last decade continues to take its toll. Unfortunately, that toll becomes bigger when it is coupled with low natural gas field prices that travel without any near term sign of going higher. The combination of these two events recently became too much for the Denali – The Alaska Gas Pipeline, owned by BP PLC and ConocoPhillips.

Three years after it opened up shop on June 11, 2008, to transport Alaskan North Slope natural gas to North

American markets, the proposed pipeline is waving the white flag and closing up. Carrying estimated capital costs of (US) \$36.0 billion (\$ 2009), the project announced on May 17th that it is in the process of withdrawing its Open Season (Docket No. PF08-26-001) filed with the Federal Energy Regulatory Commission (FERC) on April 7, 2010. The companies found that it is a very difficult environment in which to secure financial commitments from potential customers.

All this after spending (US) \$165 million and investing more than 760,000 man-hours on the project. Not to be overlooked, BP and ConocoPhillips own approximately 50% of the Alaska North Slope gas resources.

Hard days for deniers

The news out of Alaska can't be viewed encouragingly in Canada, especially for those still backing the Mackenzie Gas Project, for that proposed development faces the same competition – unconventional shale gas. Government and global energy advisors, with short-term vested interests in the project to protect, now have nowhere to hide. It is hard days for these deniers.

As presented to FERC, the Denali Alaska Mainline was to be a 1,175-kilometre, 48-inch high-pressure (2500 psig) line transporting 4.5 Bcf/d. It would have six compressor stations and connect to the Canada Mainline. It was designed for six delivery points inside Alaska. The Canada Mainline was to be a 1,641-kilometre, 48-inch high-pressure (2500 psig) system transporting 4.5 Bcf/d. It would have nine compressor stations. At Boundary Lake, the pipeline diameter would be reduced to 36-inch. The final terminus was to be near Blueberry Hill, Alberta. First delivery of Alaskan natural gas was scheduled to be delivered in 2020.

So what was once a two-horse race to transport to markets Alaskan North Slope plus Point Thomson natural gas reserves, estimated at 43 Tcf, is now down to one. Still in the starting gate is the Alaska Pipeline Project (APP), a joint effort between TransCanada Corporation and ExxonMobil Corporation. However, there is no race starter and no crowd anywhere in sight. In fact, there isn't even any interest.

On March 31, 2010, FERC approved APP's filing of January 29, 2010, requesting permission to hold the Open Season (Docket No. PF09-11-001). The 90-day exercise opened on April 30, 2010, closed on July 30, 2010. Not encouraging, 10 months on and no news on the results.

Holding approximately 12 Tcf of the North Slope's 35 Tcf of proven reserves, ExxonMobil is the largest holder of natural gas reserves on the North Slope. The company also holds a 36% interest in the 8 Tcf of natural gas reserves at Point Thomson, the second largest Alaskan natural gas field. So, in total, ExxonMobil holds an approximate 35% of the 43 Tcf of Alaska's natural gas reserves.

However, what shippers received in their APP Open Season envelope wasn't just a ballot for Plan A – the Alberta Case: a natural gas system to the southern U.S., through Alberta to Boundary Lake but also a Plan B ballot – the Valdez liquefied natural gas (LNG) case.

Presented two plans

The Alberta Case is for a 2,737-kilometre, 48-inch X80 diameter system with a capacity of 4.5 Bcf/d. The cost of this system, to be in service by 2020, is now pegged in the range of (US) \$32 billion to \$41 billion (\$ 2009).

The Valdez LNG Case is for a 1,293-kilometre, 48-inch X80 diameter system with a capacity of 3.0 Bcf/d. The cost of this system, to be in service by 2020, is in the range of (US) \$20 billion to \$26 billion (\$ 2009).

Both plans include the cost of a 93-kilometre pipeline connecting the Point Thompson field to the gas treatment

plant on the North Slope that will have an initial design capacity of 5.3 Bcf/d and include 4 trains (Alberta Case) or 3 trains (Valdez LNG Case).

Plan A will result in Alaskan North Slope natural gas crossing the international border points into the U.S. Southern States with a transportation cost in the range of (US) \$3.00 per Mcf to \$3.25 per Mcf.

Missing major costs

However, potential shippers had to make a choice between Plan A or Plan B: it was presented as an either-or situation, not both. However, at this point, there was a major missing portion – the cost of an LNG facility at Valdez that will be built and operated by others. This Alberta Case Open Season is just for the 1,182 kilometres of the system that runs through Alaska. A separate Open Season will be required for the Canadian portion.

Also missing from TransCanada's Open Season were two other cost components: the North Slope gas plant (estimated to be \$8 billion) and the Point Thompson transmission pipeline (\$1.5 billion). So added up, the cost estimate is really approximately \$35.5 billion (\$ 2008).

So, if unconventional shale gas is the undoing of the Denali system and places large question marks around APP, what does it mean to the Mackenzie Gas Project containing recoverable reserves of only 6.05 Tcf, which will support production of 850 MMcf/d for 12 years with declines to follow? Or, on another measurement scale, the Canadian project carries unit costs four times higher than those in Alaska.

The old cost estimate of \$16.2 billion (\$ 2006) for the Mackenzie Gas Project is now expected to be, at least, \$22.0 billion (\$ 2011). Included in this new cost estimate is the Mackenzie Gas Pipeline at approximately \$10.6 billion, Mackenzie Gathering System at \$4.8 billion, and field drilling and infrastructures at \$6.6 billion. Exposed are the Mackenzie Delta holdings of ConocoPhillips Canada and Shell Canada Limited.

Mackenzie Delta questions

At those new costs, ConocoPhillips Canada, holding a 15.7% interest in the pipeline and a 75% interest in the Parsons Lake field with natural gas reserves of 2.3 Tcf, will be carrying capital costs of \$3.3 billion. Shell Canada, holding a 11.4% interest in the pipeline and a 100% interest in the Nigligtagak field with reserves of 0.95 Tcf, will be carrying capital costs of \$2.3 billion.

In total, these two market-driven companies could be carrying capital costs (in both the pipeline and field drilling and infrastructures) of \$5.6 billion for a reserve base of 2.65 Tcf. In terms of "due diligence," backing out is not a difficult decision.

HEBRON – FOURTH OFFSHORE DEVELOPMENT

A discovery well drilled 31 years ago could lead to Newfoundland and Labrador's fourth offshore oilfield development coming on-stream in another six or seven years. That's the status of the Hebron oilfield in water depths ranging from 88 metres to 102 metres, located in the Jeanne d'Arc Basin, 340 kilometres offshore of St. John's.

On April 15th, the Hebron Development Application was presented to the Canada-Newfoundland Offshore Petroleum Board. Having participating interests in this development are ExxonMobil Canada Properties, operator, 36.0429%; Chevron Canada Limited, 26.6280%; Petro-Canada Hebron Partnership, 22.7289%; Statoil Canada Ltd., 9.7002%; and Nalcor Energy – Oil and Gas Inc., 4.9%.

Three fields

It is uncertain how the Offshore Board will handle this application. A review panel held a public hearing for the Terra Nova Project while a lone commissioner held the public hearing for the White Rose Project. Whichever way, a Hebron decision isn't expected until early next year.

The overall development consists of three discovered fields (Hebron, West Ben Nevis and Ben Nevis), containing a total of 700 million bbls, and incorporates four Significant Discovery Licences (SDLs) – SDL 1006, SDL 1007, SDL 1009 and SDL 1010. These four SDLs contain the most likely extent of the oil for the delineated pools within the basically heavy oil Hebron area. However, it is possible that this area could be expanded if additional studies, seismic surveys, or exploration and/or delineation drilling, proves that economically recoverable oil pool accumulations extend beyond the currently envisioned boundaries.

Even before work on this development gets underway, it is caught up in an old bugaboo – rising costs. The original development cost of \$5 billion has now been reset at \$8.3 billion (constant C\$). Between 1980 and 2010, the consortium has already spent \$538.5 million on this project. Forecasted cumulative oil recovery from these resources over a 30-year producing is estimated at 700 million bbls, with production ranging between 150,000 b/d and 180,000 b/d.

The initial Hebron discovery was followed by two phases of delineation drilling. In the first phase of delineation drilling (following 1980), the hydrocarbon that was discovered was deemed uneconomic for the time, due to either the poor oil quality or the poor reservoir quality. A second phase of delineation drilling began in 1996 to test if there was an economic upside in the area.

The Ben Nevis reservoir within the Hebron field is the core of the Hebron development and is anticipated to produce approximately 80 percent of the Hebron Project's crude oil. However, the 20-degree API crude in this reservoir presents production challenges as the viscosity can be 10 to 20 times higher than that of water. The Jeanne d'Arc and Hibernia reservoirs within the development and the Ben Nevis reservoir of the West Ben Nevis and Ben Nevis fields are also significant resources.

*20-degree
API crude*

Project activities will include construction of topside modules at a variety of fabrication locations and delivery to the Nalcor Energy - Bull Arm Fabrication facility in Bull Arm, Trinity Bay for integration and construction of a gravity-based structure (GBS) and mating of topside modules with the GBS.

One historical note: the Mobil et al Ben Nevis I-45 Hebron discovery was made just nine months after the discovery of the Hibernia field with the drilling of the Chevron et al Hibernia P-15 well. The Hibernia field commenced production on November 17, 1997, at least 20 years before first production from Hebron.

OTHER NEWS

The five-year *Mainline Tolling Settlement* filed by *TransCanada Corporation* with the National Energy Board (NEB) on February 26, 2007, and approved on May 31, 2007, reached the end of its action-packed journey on April 29, 2011, when the company filed its final 2011 tolling application. The box score on this filing had 21 parties registering comments with 10 parties either supporting the new tolling for 2011 or not opposing it; two parties were neutral, with the other parties, representing less than 10% of the Mainline's firm demand charges, opposing the new tolling. In its recent filing, the company's 2011 Eastern Zone toll (from Empress, Alberta, on the Alberta-Saskatchewan border, to Dawn, Ontario) has been set at \$2.45 per GJ. In doing so, the company, after two earlier filings had failed the smell test, requested that the annualized 2011 tolls be set in accordance with the terms of the 2007-2011 settlement. Back in 2007, TransCanada had filed an unopposed resolution from its Tolls Task Force regarding its 2007 tolls and costs for years 2008 to 2011 on its Canadian Mainline natural gas system. With that filing, the company's Eastern Zone toll increased from \$0.9447 per gigajoules (GJ) in 2006 to \$1.02 per GJ in 2007, up 7.9%. But this was just the start of a journey that was to get a lot rougher for both TransCanada and the producers. Now the very future of the Mainline is in doubt. In the five-year period running from 2007 to 2011, the Eastern Zone toll has increased by \$1.5053 per GJ or 159.3% (see table 2). In another measurement, the toll has increased at an annual rate of 21% and producers who were happy back in 2007 are now dejected.

Table 2
TransCanada Corporation
Eastern Zone Tolls
2006 - 2011
(\$ per gigajoule)

2006	\$0.9447
2007	1.0195
2008	1.30496
2009	1.1881
2010	1.6381
2011	2.45

TransCanada will continue charging tolls at the new levels for the remainder of 2011 and will adjust for the difference between the annualized final tolls and the tolls charged in 2011 on a retrospective basis in 2012. Not only have natural gas prices gone into the tank in the past five years, firm contract levels and overall throughput on the Mainline has decreased significantly. Long-haul contracted volumes are down by approximately 70%. Although costs have also decreased over this period, they have done so at a slower rate. The mathematics used to calculate the annualized final 2011 tolls had the systems'

Gross Revenue Requirement set at \$1,883 million. TransCanada forecasts that Miscellaneous Revenue will be \$485 million, resulting in a Net Revenue Requirement of \$1,398 million. However, as a good pipeliner, TransCanada accepts none of the blame for the tolls that are much higher than ever imagined back in 2007. According to the company, it has all come about due to declining throughput and shifts in contracting practices, not increased costs, and results from matters outside its control. Somehow or other, poor "due diligence" never gets mentioned. Where this TransCanada-natural gas producer-tolling puzzle goes after this year, is anyone's guess. The company remains open to settlement discussions with stakeholders for 2012 and beyond, but it will continue preparation of its 2012-2013 Application to be filed in the event a negotiated agreement cannot be achieved. Part of the producing community wants to see the issue, in need of a major structural overhaul, given to the NEB. This will include having the company sharing some of the risks and lead to a major hearing next year. However, other producers, in spite of what has happened over the last five years, don't want to see the NEB involved. This group wants to try and work out a solution with TransCanada and they want it to file its 2012 tolling application much sooner than its proposed filing date of October 31, 2011. Certainly the company knows that an Eastern Zone toll of \$2.45 per GJ can't be maintained. To do so will have it losing more market share and doing so at a faster rate.

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The effects of the fire on January 6, 2011 at the *Horizon Oil Sands Project* operated by *Canadian Natural Resources Limited* are now known and they aren't pretty. Led by the first quarter 2011 production of only 7,269

b/d at its Horizon operation – down 91.6% from production of 86,995 b/d in the first quarter of 2010, the company's total first quarter 2011 production of 566,231 b/d of crude oil equivalent (63% oil weighted) was down 44,325 b/d of crude oil equivalent or 7.3% from first quarter 2010 production of 610,556 b/d of crude oil equivalent. In turn, this downturn in production played havoc on Canadian Natural Resources' net earnings, which in the first quarter of this year were only \$46 million, down \$688 million or 93.6% from first quarter 2010 earnings of \$735 million. Current plans call for Horizon to recommence production, in two phases, in the third quarter. The first pair of coke drums – 2A and 2B – supporting synthetic crude oil production of 55,000 b/d will be on-stream in the third quarter of this year, a quarter later than originally planned. The second pair of coke drums – 1A and 1B – supporting synthetic crude oil production of 55,000 b/d will also be commissioned in the third quarter. If these schedules are met, Horizon's 2011 production will average in the range of 45,000 b/d. However, those time lines are now in doubt. Due to forest fires that were burning out of control near the site, the company had to stop repairs in mid-May. Horizon's repair costs are now estimated to be in the range of \$350-to-\$400 million and are likely approximately \$50 million more than originally estimated, with a major portion of its operating costs to be covered by its (US) \$2.0 billion blanket insurance policy.

Following the opening of the Great Canadian Oil Sands operation (now Suncor Energy Inc.) in 1967, Syncrude Canada Ltd. in 1978, and the Athabasca Oil Sands Project in 2003, the Horizon operation, which produced its first bbl of 34 degree API light, sweet synthetic crude oil on February 28, 2009, was Canada's fourth oil sands mining operation. Now the focus is directed at the cost estimates for the next phase of development at Horizon that will take synthetic oil production to the 232,000 b/d to 250,000 b/d level. Although no total cost estimate is available, the company says that it will limit annual expansion expenditures to \$2.0 to \$2.5 billion. Not unexpectedly, the events at Horizon have played upon the company's share price. During a five-month period (January 1-to-May 31, 2011) when the S&P/TSX Composite Index has gone up by 2.7% and the S&P/TSX Energy Index has gone up by 3.9%. Canadian Natural Resources' share price has moved from \$44.55 per share to \$42.17 per share, down 5.3%. On the day that Canadian Natural Resources' company's Board of Directors gave thumbs up to proceed with Phase 1 of the Horizon Oil Sands Project, its market capitalization increased by \$0.9 billion or close to 10% of the estimated cost of the project's total costs (Phases 1, 2 and 3) then estimated to be \$9.6 billion. Now six plus years later, Canadian Natural Resources has a market capitalization of \$46.4 billion, approximately five times \$9.7 billion, the completed cost of Phase 1. Most encouraging has been the frankness of the company's news releases during the many bad periods. The company has gone out of its way to keep investors and watchers aware of the hardships at Horizon.

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Two thoughts come to mind. First, is there a role for this new natural gas technology in Canada? Secondly, how quickly unconventional shale gas advances are speeding up conventional gas developments. Last month (May), *Royal Dutch Shell plc* gave the go ahead to building the world's first *Floating Liquefied Natural Gas (FLNG) facility* for a development in Australia, which is too small to be developed via a pipeline connection and a conventional onshore LNG processing plant. This estimated \$10-billion specially constructed ship will be used to develop the company's Prelude and Concerto gas fields off the northwest coast of *Western Australia*. In 2007, Shell (100%) made the Prelude discovery on the 1,000-square kilometre permit WA-371-P, in the Browse Basin, 475 kilometres north-northeast of Broome, Western Australia, in 2007; and two years later the company discovered the Concerto gas field on the same permit. Together, the two fields lying 200 kilometres from land, contain reserves of 3 Tcf of liquids-rich gas. Shell has awarded the contract for the design, construction and installation of multiple FLNG facilities to the consortium of Technip and Samsung Heavy Industries of South Korea. It will be completed in 2017 and will be done in accordance with Shell proprietary design. The FLNG will be moored by four groups of massive mooring chains in 250 metre-deep water with each mooring chain held to the sea floor by suction piles the size of small houses. The vessel will be built to withstand severe offshore weather conditions including a Category 5 cyclone. It will stay moored for 25 years and support production of 5.3 million

tonnes per annum (mtpa), containing 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 nmtpa of liquefied petroleum gas. Thus, in a period of 10 or 11 years, a discovery representing production of 110,000 b/d of crude oil equivalent will be on-stream. Ocean-going LNG carriers will offload liquefied gas chilled to minus 162 C and shrunk in volume by 600 times, and other products, directly from the facility out at sea for delivery to offshore markets.

The size of the FLNG is staggering and it doesn't take too long before you realize that it is many times larger than either of the two Floating Production Storage and Offloading Vessels (FPSO) that are operating offshore Newfoundland. Shell's FLNG will be 488 metres long and 74 metres wide and when fully loaded will weigh approximately 600,000 tonnes, of which 260,000 tonnes (43%) will consist of steel. In another measurement of scale, the FLNG will be about six times the size of the largest aircraft carrier and will have five times the amount of steel as contained in the Sydney Harbour Bridge. In comparison, the Terra Nova FPSO built by Daewoo Shipbuilding and Marine Engineering in Okpo, South Korea, is 292.15 metres long, 45.47 metres wide, has oil storage of 960,000 bbls and has a displacement of 190,000 long tons. Shell's upstream investment in Australia over the next five years will be approximately \$30 billion with most of it geared to LNG developments. The company already has a 25% interest in Chevron Corporation's (US) \$43.5 billion Gorgon-Jansz LNG project, on the North West Shelf with reserves now estimated to be over 60 Tcf. LNG shipments from the first phase from the terminal to be located on Barrow Island are scheduled to commence in 2014. Are there other uses for this technology? Two years ago, the Commonwealth Scientific Industrial Research Organisation estimated that there was 140 Tcf of "stranded" gas in the waters offshore Australia.

S&P/TSX COMPOSITE INDICES

	<u>6/1/11</u>	<u>5/1/11</u>	<u>6/1/10</u>	<u>52-week</u> <i>high</i>	<i>low</i>
<i>S&P/TSX</i>	13,802.88	13,944.79	11,762.99	14,329.49	11,065.53
<i>ENERGY</i>	335.83	347.57	285.92	370.75	260.46
<i>UTILITIES</i>	227.96	221.06	189.00	232.40	186.38

CRUDE OIL PRICES

(Monthly Average - 40 degree API - Edmonton)

	<u>5/11</u>	<u>5 Mo/11</u>	<u>1/11</u>	<u>5 Mo/10</u>	<u>5/10</u>
<i>(C) \$/bbl</i>	\$101.67	\$92.99	\$83.93	\$79.38	\$71.21

Source: Imperial Oil