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TRANSCANADA – ON THIN ICE

These aren't good days for the shareholders of a 60-year old company that advertises itself as a leading developer and operator of North American energy infrastructure including natural gas and oil pipelines, power generation and gas storage facilities. TransCanada Corporation, which admitted last year that it must operate with better financial disciplines, is now on thin ice.

The company's new president and chief executive officer disclosed that the company needs a new business plan that is more closely controlled and lower risk. Considering that the company's old business model is showing definite signs of wear, the new head is divulging that he is taking over a "fixer-upper." At the top of his "to do" list is a review of TransCanada's revenue streams. Led by declining U.S. demand for Canadian natural gas, revenues from the company's natural gas transportation sector are falling, and falling fast.

TransCanada has become a company with a split personality. It has too many high profile energy issues and projects on the go, which are facing major roadblocks, and may be likely additions to a trophy case containing other recent failures.

Some bad projects

During the five-year period starting in 2004, TransCanada entered two liquefied natural gas projects in a less than disciplined manner. In Canada, its Cacouna Project that it was going to build with Petro-Canada on the St. Lawrence River near Rivière-du-Loup, Quebec, came to an end in late 2008. Reasons were no supply, cost pressures and excess North American regasification capacity.

In the United States, the company had no better luck with Shell US Gas & Power LLC in building its Broadwater Energy Project in the New York waters off Long Island. This development was rejected by the State of New York in the spring of 2008, and a year later it met the same fate from the U.S. Department of Commerce.

But this is far from a destitute company, which has approximately 4,200 employees. TransCanada has a market capitalization of \$30 billion, is trading at \$40.33 per share (August 31, 2011) on the high side of its 52-week high-low of \$43.72 to \$35.49 per share and recorded 2010 net income of \$1,227 million. Also, not to be overlooked, the investment community prizes the company.

In the following, we discuss the following matters confronting the company: Mainline tolling, Keystone XL System, Houston Lateral and Cushing Marketlink Open Season, Alaska Pipeline Project and its Board of Directors.

Mainline Tolling

The eyewall of the storm coming the company's way next year will be the tolls to be charged on TransCanada PipeLines Limited's (TCPL) Mainline system and how they are set. The company and its stakeholders group now recognize that the almost completed five-year Mainline settlement running from January 1, 2007, to December 31, 2011, which defined how the system's net revenue requirements were determined annually, was badly created. In a recent filing, the company's 2011 interim Eastern Zone toll (from Empress, Alberta, on the Alberta-Saskatchewan border, to Dawn, Ontario) has currently been set at \$2.08 per gigajoule (GJ).

Unfortunately, events during this period have gone from bad to worse. During the five-year period, Alberta's natural gas production has decreased by 5.5% per annum, firm service deliveries on TransCanada's Mainline have decreased by 17% per annum, and the Eastern Zone toll on the Mainline has increased by 15% per annum. To add to the gloom, the cycle is far from over. The near-term future has production and deliveries decreasing at faster rates due to transportation tolls under the current system that will be heading higher. This has become a labyrinth without an exit.

*The cycle
isn't over*

To make matters worse, there is no harmony amongst the stakeholders group, consisting of approximately 65 companies, individuals and organizations, of which a third are active members, a third are inactive and the remaining third sit on the side lines. But bear in mind that the present natural gas playing field is so much

different from that in existence in 2006 when the current TransCanada tolling framework was being negotiated. It was signed in an upbeat time. Many of today's hurdles were visible then, but disregarded.

In pretty clear language, the NEB sent a strong message to TransCanada in mid-June showing that it is concerned as to how quickly the tolling situation on the company's Mainline system is deteriorating. TransCanada had originally said that it would file the application, containing a comprehensive suite of business model, toll design and service changes, by October 31, 2011. However, considering that the parties, after a year of discussions, have basically made no headway on this issue and that the level of uncertainty is contrary to the public interest, the NEB directed the company to file by September 1, 2011.

Major hearing next year

If required, the NEB intends to hold a public hearing to consider that application in the first quarter of 2012 and to release a decision by the end of the second quarter of 2012. This is a quick turnaround to a major hearing that will have a most important bearing affecting the future of natural gas producers in the Western Canadian Sedimentary Basin.

Insiders say that the company will be requesting, in its September 1st filing, that it be allowed to change the depreciation rate for the three main geographical areas of the Mainline system – the Prairie system, the Northern Ontario system and the Eastern Triangle. If TransCanada gets this and other changes it hopes to get, its 2012 Mainline toll to Dawn will be in the range of \$1.40-to-\$1.45 per GJ, down from the 2011 interim toll of \$2.08 per GJ. All this is happening when the 2011 average AECO price is \$3.79 per GJ.

In this new filing, the regulatory legal community will hit the jackpot as TransCanada advances “a solution of shared responsibility.” Not everybody will be happy with how the NEB's interprets this new feature. As such, the ruling will be around in the Canadian court system for a decade until a final ruling comes from the Supreme Court of Canada.

The biggest disappointment of the current five-year tolling agreement is that industry leaders like TransCanada, the Canadian Association of Petroleum Producers (CAPP), Industrial Gas Users Association, the Government of Alberta and the NEB, didn't ask for a time out when it became evident that it needed a complete overhaul. Too much weight was being placed on future events, which never seem to happen. Now TransCanada is making more future promises as it puts more pressure on shippers to sign on to another tolling agreement. But this time, producers aren't buying these future possibilities.

The NEB is going to have to take a very pro-active role at this 2012 hearing: it is hard to imagine that its decision on the direction of future Mainline tollings will please all. TransCanada's shareholders won't come out of this fray unaffected. Expect push back from many of the stakeholder group who want parts of the current Mainline system written off with shareholders taking a hit.

Facing write downs

The current Mainline tolling agreement looks like it was taken directly from the European Central Bank's playbook as it deals with the sovereign debt crisis affecting most of the European Union. In that battlefield, shareholders aren't untouched by events as Euro banks face massive write downs, some reaching close to their market capitalizations.

As such, TransCanada now faces the same problem confronting Greek banks – withdrawals. In the latter case, customers are taking their money and placing it in other countries. In the TransCanada case, shippers are directing their volumes to other systems.

Showing that it realizes that it is running out of options, TCPL filed a 2011 Eastern Mainline Application with the NEB on July 18, 2011. Under this proposed system, the company will be able to provide natural gas under “bidirectional flow” arrangements to markets in Central Southern Ontario, including Toronto. Included in this Section 58 Application is 13.2 kilometres of new pipeline in the vicinity of Parkway plus a Niagara Border Meter Station. Total cost of this new bidirectional services to be in service by November 1, 2012, is \$130.3 million.

But not everybody in the TCPL Task Force is happy. So far CAPP and Centra Gas Manitoba Inc. have filed their concerns. At this point, it isn’t known how the NEB will handle this matter. It is possible that it could get placed into the company’s 2012-2013 Toll Application.

Keystone XL System

If the Northern Ontario political debate in the House of Commons in 1956 was the defining point in TCPL’s entry into natural gas transportation, then events now going on in Washington surrounding the Keystone XL Pipeline are certainly a defining point for TransCanada’s ticket into the oil transportation side of pipelining. But alas, events in the last two and a half years haven’t increased the odds that this project will get approved.

Hardball politics

Ironically, nothing has changed in the last 55 years. The key decision-making factor in Washington is the same one that the company faced in Ottawa – hardball politics. Regrettably, the Canadian oil industry’s lack of attention to details in the last 15 years, especially on the oil sands file, isn’t doing the current situation any good.

The fly in the ointment is increased greenhouse gas (GHG) emissions that come with oil sands production (mining and in situ) that the CAPP forecasts will increase from 1,470,000 b/d in 2010 to 3,000,000 b/d in 2020. The largest increase in the next 10 years will come from in situ production. Further down the U.S. list of concerns is the possibility of pipeline oil spills as the oil makes its way through sensitive terrain.

Finally on August 26th, TransCanada caught a break that wasn’t related to a pipeline stress related matter. It was three words contained in a six-paragraph Fact Sheet, which summarized a nine-volume, more than 1,000 page study, regarding the Keystone XL system: “No significant impact.”

That is what immediately caught the attention of the backers of the TransCanada Keystone XL system as the U.S. Department of State released the Final Environmental Impact Statement presented by the Bureau of Oceans and International Environmental and Scientific Affairs. This is the third Environmental Impact Statement that the U.S. Department of State has issued on Keystone XL since the review process commenced in 2008. However, last month’s release contained 57 Project-specific Special Conditions.

The Bureau’s investigation found that the emissions contained in the Canadian sourced bitumen that would be shipped in the pipeline are about 17% higher than that contained in the average U.S. crude streams but only 2% higher than those contained in heavy crudes from Venezuela and Mexico, which are in fast decline.

A positive step forward

The State Department will now have 90 days to decide whether the line meets the national interest test. During that period, representatives from eight U.S. agencies will study the results. Bear in mind that the August 26th release isn’t a final document, however, it is a positive step forward for those backing the building of the system.

It didn’t take TransCanada long to get this word out. Within an hour it released a press release dealing with the

Bureau's findings. This was quite different from how the company has publicly dealt with the issues surrounding the Bison Pipeline in Wyoming.

However, not so happy with the August 26th findings are the environmental activists who pledge to fight this proposed pipeline system right to the next United States presidential election slated to be held on November 6, 2012. They continue their campaign of civil disobedience outside the White House. Also, a former U.S. vice president doesn't want the pipeline built in his country, the current Governor of Nebraska doesn't want the pipeline built in this State and many of the First Nations in Canada are on the warpath with their opposition. This matter won't die.

U.S. shale production

As the Canadian government and oil industry await a final decision on the fate of the \$7-billion pipeline later this year, at play is a detail that gets overlooked – not all the oil in the 700,000-b/d system that will be making its way from Hardisty, Alberta, to the U.S. Gulf Coast will be oil sands production. Seventy-five percent (525,000 b/d) will be Canadian production with 25% (175,000 b/d) coming from the Bakken oil shale plays primarily in North Dakota and Montana.

Seventy-five percent of any cost overruns will be made up through higher tolling. Now TransCanada has an additional Open Season bidding underway from Hardisty to Houston, Texas, or Port Arthur, Texas (see below).

A U.S. turndown of this pipeline system carries with it unpleasant results. Not only has 525,000 b/d of Canadian oil sands production got to find a new home, it will also immediately discount the wellhead price of Canadian crude oil even further. Attention will immediately turn to the Northern Gateway pipeline project to ship oil sands production from Alberta to the west coast of British Columbia. But things aren't going well here as opponents call the shots. Oil sands projects and expansion plans will get pulled off the table as industry looks for new markets. But these won't appear overnight.

Sadly, industry allowed the foes of the Keystone XL Pipeline to take over the Speakers Platform and paint the system as delivering 700,000 b/d of environmentally bad Canadian oil sands production to the U.S. Unfortunately, nobody in favour of the system seems to have the backbone to stand up and make the case that a sizeable volume of the oil production arriving in the Gulf Coast will be non-oil sands U.S. production. Additionally, that production has also paid U.S. taxes and royalties and assisted the country's balance of payment difficulties.

Currently Keystone XL has take-or-pay contracts for approximately 400,000 b/d from Hardisty to the Gulf Coast. The average length of these contracts is in the range of 18 to 20 years. Also coming on board at Baker, Montana, is 65,000 b/d of U.S. Bakken production. This contains a five-year shipping contract.

A psychological blow

But more than barrels and dollars are at stake here. A U.S. turndown will be a psychological blow for TransCanada, which is coming off less than first class efforts in the North (both Alaskan North Slope and Mackenzie Delta). The Canadian oil industry will also have to retrench and work out a new way of presenting itself. Its concentration on presenting itself only at investment conferences hasn't gone well.

In Canada, TransCanada Keystone Pipeline GP Ltd. filed the Keystone XL Pipeline Project application with the NEB on February 27, 2009, to construct and operate the system. The application was heard over an 11-day period in Calgary running from September 15 to October 2, 2009. The decision (OH-1-2009), containing 22 conditions, which approved the building of 529 kilometres of new pipeline and related facilities in Canada, was released on March 11, 2010.

The \$1.7 billion Canadian portion of the overall Keystone XL Pipeline will transport crude oil from Hardisty to the Canada/U.S. border at Monchy, Saskatchewan. It will have an initial capacity of 700,000 b/d of crude oil and can be expandable to 900,000 b/d. Approximately 90% of the 700,000 b/d capacity has been allocated under long-term shipping arrangements.

No Canadian construction yet

Key conditions centre on safety, protection of the environment and landowner rights. The NEB also imposed an obligation to strictly monitor GHG emissions. At least two months prior to construction, the company has to file a quantitative assessment of GHG emissions expected to directly result from the building of the pipeline and its associated facilities. Also, TransCanada must outline the methodology it used, what variables might be included in those results and describe mitigation measures to reduce emissions.

Although approved 17 months ago, no construction has yet taken place in Canada.

The Keystone Shippers Group consists of Canadian Natural Resources Limited, ConocoPhillips Canada Marketing and Trading ULC, Cenovus Energy Inc., Shell Trading Canada, Total E&P Canada Ltd and Trafigura Canada General Partnership.

Some of the companies involved shipping U.S. production on the Keystone XL system include Anschutz Exploration Corporation, ConocoPhillips, EOG Resources Inc., ExxonMobil Corporation, Hess Corporation, Hunt Oil Company and Marathon Oil Company.

Houston Lateral and Cushing Marketlink Open Seasons

In mid-August, TransCanada initiated two 63-day open seasons closing on October 17, 2011, to obtain additional firm commitments from interested parties to transport crude oil from Cushing, Oklahoma. The proposed Houston Lateral will involve an expansion of capacity and construction of an approximate 80-kilometre pipeline extension from the proposed Keystone XL system to the Houston refining centre with a refining capacity of 4 million b/d.

If interest is shown, the company will proceed with the necessary regulatory applications for approvals to construct and operate the facilities required for the capacity expansion and provide transportation services from Hardisty to Houston.

This Houston Lateral and capacity expansion is included in the original scope of the U.S. Presidential Permit application process, which is currently undergoing review and is expected to be concluded by the end of this year. If approved, transportation for Canadian crude oil to Houston on the Keystone System could begin in 2014.

Additional capacity

TransCanada has also launched an additional open season for interested parties to move U.S. crude oil production 936 kilometres from Cushing to Port Arthur. This Cushing Marketlink Project follows up on its successful open season held last year when shippers committed for capacity of 150,000 b/d. This Marketlink Project will deliver crude oil using pipeline facilities that form part of the \$7-billion Keystone XL System. Additional capacity space this year is believed to be in the range of 100,000 b/d to 150,000 b/d.

Alaska Pipeline Project

Last month, the company's shareholders and natural gas markets received news that surprised no one: the Alaska

Pipeline Project (APP) has no shippers. The company told the Alaska State Legislature that it and partner ExxonMobil Corporation, 16 months after initiating APP's Open Season on April 30, 2010, still had no takers. For the record, this Open Season closed on July 30, 2010.

Twin Towers of bad news

Regrettably, this lack of interest appeared in both APP's Open Season envelopes. The Alberta Case calls for a natural gas system to the southern U.S., through Alberta to Boundary Lake and the Valdez liquefied natural gas (LNG) Case.

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).

If there was any joy in Anchorage last month, it was that State officials learned that ExxonMobil had reached a tentative development settlement regarding its 36% interest at Point Thomson, Alaska's second largest natural gas field, which holds reserves of 8 Tcf.

But that still wasn't enough to overcome the Twin Towers of bad news that have challenged both the Alaska North Slope and Mackenzie Delta gas developments for the last five/six years: the explosion in North American unconventional shale gas plays coupled with low natural gas field prices that travel without any near term sign of going higher.

These are exactly the same roadblocks faced by BP PLC and ConocoPhillips, the sponsors of the Denali – The Alaska Gas Pipeline. These companies announced on May 17, 2011, that they were throwing in the towel on their plan to build a U.S. 1,175-kilometre, 48-inch high-pressure (2500 psig) line transporting 4.5 Bcf/d with estimated capital costs of (US) \$36.0 billion (\$ 2009). At the Canadian border it would have connected to the Canada Mainline, a 1,641-kilometre, 48-inch high-pressure (2500 psig) system transporting 4.5 Bcf/d.

At the time of raising the white flag, the companies had spent (US) \$165 million and invested 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.

ExxonMobil joined forces with TransCanada in the Alaska Pipeline Project in mid-June 2009. 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. In total, ExxonMobil holds an approximate 35% of the 43 Tcf of Alaska's natural gas reserves.

No long-term contracts

So even with TransCanada's partner holding a proven North Slope reserves base of 15 Tcf, at least double that held by the Canadian industry in the Mackenzie Delta, it can't get any interest from potential shippers to sign long-term contracts.

As per an earlier agreement, the State of Alaska had granted the APP \$500 million in state subsidies. As of last month, the APP had spent \$288 million, of which \$94 million had been reimbursed by Alaska. Regardless of where things stand now, the two companies expect to spend \$700 million, of which \$500 million will come from Alaska.

In its 2010 fourth quarter financial statement, TransCanada wrote off \$146 million (\$127 million after tax)

recorded against the Mackenzie Gas Project (\$0.18 per share). Now the company says it will expense any future advances to the Aboriginal Pipeline Group for the Mackenzie Gas Project. History shows that TransCanada made this investment in spite of not being invited: it used the backdoor.

Thus, TransCanada's shareholders know at first hand Robert Service's words written so many years ago: "The Northern Lights have seen queer sights."

Board of Directors

Many close observers of TransCanada believe that it should be operating with new members on its Board of Directors. Currently, the 12-member Board has an average age of 64 who have served an average 7 1/4 years.

Younger blood needed

Younger blood is needed. Only one new Board member has been appointed since 2007 and that is the company's new chief executive officer. Six Board members are over the age of 65, three between 60 and 65 years and only three under the age of 60.

So all Board members, including the chief executive officer who was vice-president, were on the Board during the days when the company's business plan lacked discipline and took on too much risk.

The present Chair has been a Director since 2002 and the Chair since 2005. As a previous Chair's term was noted for cutting the company's dividend when its financial situation required such a move, the present Chair's term will be noted for watching the decline of the Mainline system.

NEWFOUNDLAND – A RANGE OF OFFSHORE PRINCIPLES

A Canadian east coast energy regulatory body that was formed in 1986 to regulate oil and gas activity in its offshore waters covering 7,365,000 hectares is now signaling that not all of its waters will be administered under the same set of policies. That's the position that the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) has placed itself in as it treats industry's activities in the waters off its west coast (Gulf of St. Lawrence) much differently from those off its east coast (Atlantic Ocean).

The C-NLOPB has sure picked a fine time to become politically concerned about environmental matters vs. jobs in its offshore waters. During the last 20 years, in excess of 20 deepwater wells have been drilled on the east coast of Canada without either the C-NLOPB or the Canada-Nova Scotia Offshore Petroleum Board showing any concern about having relief drilling rigs in Canadian waters in the case of a blowout. Also, neither Board has shown any concern whether relief rigs named on deepwater drilling applications were, in fact, either in Canadian waters or capable of drilling in Canadian east coast waters.

Jobs over blowouts

At play here are two offshore wells – one that is planned for drilling by Corridor Resources Ltd. on lands administered by the C-NLOPB in the Gulf of St. Lawrence and one well that is currently being drilled by Statoil Canada Ltd. in the Flemish Pass in the Atlantic Ocean, 500 kilometres east of St. John's.

Gulf of St. Lawrence

Corridor Resources is proceeding with its drilling plans on exploration license (EL) 1105 in the Newfoundland sector of the Gulf of St. Lawrence. The 51,780-hectare block was awarded to the company (100%) on January 15, 2008, for a nine-year term. The first period of this EL, which goes under the name 'Old Harry,' expires on January 15, 2014. The license is located in the Laurentian Channel, at a water depth of approximately 450 metres, approximately 85 kilometres from Magdalen Islands, Quebec, and 70 kilometres from Cape Anguille, Newfoundland. But to make things more interesting the prospective structure lies within the offshore sectors of both Quebec and Newfoundland and Labrador.

Large reserves potential

Last fall, Corridor Resources conducted a geohazard survey over an area of approximately 4.5 by 5 kilometres and in February 2011 submitted its Old Harry Exploratory Drilling Project Description to the C-NLOPB. Called the most prospective unexplored oil and gas area in Eastern Canada, Old Harry comes with its backers touting large reserves potential – either two billion bbls of oil or 5 Tcf of natural gas.

Last March, Canada and Quebec signed a revenue agreement affecting future oil and gas production in the Quebec sector of the Gulf of St. Lawrence. The agreement will have the two governments setting up a joint offshore board similar to the two offshore boards already in operation in Newfoundland and Nova Scotia. As with Newfoundland and Nova Scotia, although the resources are federally owned, all the revenues will end up in Quebec City.

Currently, there is a moratorium in place until 2012 that affects seismic work and drilling in the Quebec portion of the Gulf. Interestingly, it is still uncertain as to where the underwater boundary lines lie in the Gulf between Quebec, Newfoundland, Nova Scotia, New Brunswick and Prince Edward Island. Back in 1964, Quebec and the four Atlantic provinces agreed to a Gulf boundary line. However, it was ruled not valid in 2002 because it hadn't been submitted to the federal government.

The Gulf of St. Lawrence/Laurentian Channel isn't exactly virgin territory for exploration drilling. Over the 40-year period between 1943 and 1983, 11 wells were drilled with most of the tests plugged and abandoned with no shows. A couple of wells recorded shows of gas and one well was noted as being a gas discovery. However, it only recorded a test of 5.3 MMcf/d. So, in essence, the results show why industry hasn't returned to this body of water in the last 28 years.

A footnote, most of the companies that participated in the drilling of these 11 wells, Amoco Canada Petroleum, Canadian Petrofina, Hudson's Bay Oil & Gas, Irving Oil, Murphy Oil, Petro-Canada, Shell Canada and SOQUIP are no longer in existence.

Of historical note, the first Canadian offshore well ever drilled – Island Development Hillsborough No. 1 – was drilled in the area. The new field wildcat drilled in Hillsborough Bay, Prince Edward Island, was spudded in 1943 in water depths of 5 metres and taken to depth of 4,479 metres before being declared a dry hole.

Faces a major problem

But Corridor Resources, with a market capitalization of only \$232 million, faces another problem: Where does it get the money to drill a well lasting over 60 days that could cost well in excess of \$30 million? Although the company has issued an Expression of Interest for contracting a suitable drilling rig, it is more interested in obtaining a drilling partner or partners. In this regard, Corridor Resources has engaged Macquarie Capital Markets to assist in this search.

Finally, the time line – will it be able to conduct its regulatory dance with C-NLOPB, find drilling partners and be able to get a well underway within the next 29 months?

If you think that you have seen this inter-provincial energy dance now being performed in the Gulf of St. Lawrence before, you have. For a 40-year period, Nova Scotia and Newfoundland fought an energy turf war over control of the Laurentian Channel – the 60,000-square kilometre sub-basin lying between Cape Breton and southwestern Newfoundland.

Finally, in 2002, a Canadian arbitration panel ruled that Newfoundland had administrative control over 45,000 square kilometres (82.4%) with Nova Scotia having control over 9,600 square kilometres (17.6%) of the disputed area. In an earlier international decision, France had won the rights to the 5,400-square-kilometre area surrounding the islands of Saint-Pierre and Miquelon.

Another east coast fray

The prize here was at the ends of many rainbows painted by various sources. In a 1970s study, the Geological Survey of Canada estimated that the sub-basin contained natural gas reserves of between 8 Tcf to 9 Tcf and crude oil reserves of between 600 million bbls to 700 million; Nova Scotia said that the area held three Sable Offshore Energy Projects and two Hibernias; while not to be outdone, the

National Energy Board estimated the marketable ultimate natural gas potential to be in the range of 6 Tcf.

So far only two wells have been drilled in the Laurentian sub-basin. In 2001, ExxonMobil Canada Properties, with Gulf Canada Resources Limited (now ConocoPhillips Canada) and Murphy Oil Limited as partners, drilled the Bandol #1 well in French waters, an approximately \$30-million, 60-day dry hole, 150 kilometres south of Saint-Pierre and Miquelon.

Last year ConocoPhillips Canada drilled the East Wolverine G-37 test in water depths deeper than 2,000 metres in the Laurentian sub-basin to a depth of 6,600 metres. As yet, no results have been released.

Facing the strongest public commentary that it had ever received in its 26-year history regarding the environmental aspects regarding the drilling of a well, the C-NLOPB wrote to the federal government in June recommending that a mediator be appointed or a review panel formed to review the drilling of the Old Harry location.

Two months later, Ottawa placed the ball back in Newfoundland's court by requesting that the C-NLOPB conduct a two-pronged environmental assessment to examine Corridor Resources' request to drill an offshore well on EL 1005. The federal Minister of the Environment also requested an update of the 2007 Strategic Environment Assessment (SEA) for the Western Newfoundland Offshore Area.

As such, the C-NLOPB is now establishing a working group to oversee the process of updating the SEA for the Western Newfoundland Offshore Area, which will begin with the development of a scoping document for the SEA. A major portion of this review process will be a public consultation.

An independent review

Late last month, the C-NLOPB appointed a person to conduct an independent review of Corridor Resources' proposed drilling program on EL 1105. Bernard Richard, from Cape-Pelé, New Brunswick, is a lawyer, former social worker and politician. Wow! This independent reviewer will focus on the potential environmental effects of the proposed drilling of a single exploration well on EL 1105. Public consultations will be held in the five jurisdictions bounded by the Gulf of St. Lawrence (Newfoundland and Labrador, Prince Edward Island, Nova Scotia, New Brunswick and Quebec). The final report will be presented to the C-NLOPB, which will also be made public.

Unfortunately, under the Terms of Reference, there is no date given as to when this review must be completed. It's as if the C-NLOPB has never heard of the Joint Review Panel set up to hear the Mackenzie Gas Project application. With distressing results, that group also operated without a time limit.

However, this isn't simply an encounter between Quebec and Newfoundland as to exactly where a boundary line lies. Also joining in are environmentalists, fishermen and some first nation groups in the five eastern provinces. Thus, legal battles will be the order of the day before a drill bit ever hits the seafloor again in the Gulf.

Atlantic Ocean

On the other hand, life is much more basic off the east coast of Newfoundland. This is 'Drill Baby, Drill' country for the C-NLOPB, where it doesn't have to worry about environmental issues. The only topic of concern here is jobs, especially since last year, when the past premier said that a deepwater blowout wasn't a major concern since crude oil would never reach the shores of his province.

Rule of 'Closed Disclosure'

So issues raised by last year's blowout of BP PLC's Deepwater Horizon well in the Gulf of Mexico haven't reached the waters of eastern Canada. Environmental matters are part of a foreign language and holding a hearing into a deepwater drilling application will never happen until the C-NLOPB is forced to reverse its rule of 'Closed Disclosure.' Thus continues the "hope-and-a prayer that nothing goes wrong" policy that has been in place for years.

Also on the east coast, there is no need to tell the public that no rigs are available in Canadian waters to assist if a deepwater well in this area runs into problems. Further, it will only confuse matters more if the public is told that relief rigs on call from outside Canadian waters don't contain certifications to drill in Canadian waters.

That's the fortuitous set of circumstances that Statoil Canada faced when it spudded its Mizzen F-09 well in the Flemish Pass on July 29th on Significant Discovery License (SDL) 1047. The new well is being drilled in the 1,100-metre deep Flemish Pass, located approximately 500 kilometres east of St. John's by the Henry Goodrich semi-submersible rig, owned by Transocean Ltd. The rig, built in 1985, has a maximum drilling depth capability of 9,144 metres in a maximum water depth of 610 metres.

Showing that it had heard about events in the Gulf of Mexico last year, the Province released its report last April dealing with its offshore oil spill prevention and response capabilities. This initial 90-day study, which was commenced in May 2010, contains 25 recommendations and still Statoil Canada's Mizzen F-09 deepwater well is being drilled without a word.

The Henry Goodrich is currently operating offshore Newfoundland under a three-year rig-sharing agreement that Transocean signed with Husky Energy Inc., Statoil Canada and Suncor Energy Inc. on April 27, 2010. The Rig Share 2 Agreement came into effect in December 2010.

Not allowed in Norway

However, even before this new deepwater well got underway, many were questioning whether the environmentally conscious Norwegians should be allowed to drill in Canadian waters under circumstances that would not be allowed in either the Norwegian North Sea or Norwegian Shelf. But certainly none of that questioning ever found a home inside the offices of the C-NLOPB, which finds itself in the uncomfortable position of never administering a stand-alone commercial discovery since the National Energy Program came to an end in 1986.

Bear in mind that it was only last year when caught flat footed as Chevron Canada Resources commenced drilling its deepwater Lona O-55 well in the Orphan Basin that the C-NLOPB established some regulatory oversights regarding deepwater exploration. But there isn't any word as to whether Statoil Canada is currently drilling with any of these 2010 regulatory oversights in place.

22-degree API oil

This summer's well is a follow-up to the StatoilHydro Canada Mizzen O-16 well drilled by Statoil Canada, operator, 65%; and Husky Energy, 35%, in 2008/09. That 99-day well was taken to a depth of 3,758 metres by the Henry Goodrich rig with one test conducted in an 11-metre interval at the 3,213-metre level, which recovered 3,780 bbls of 22-degree API oil. Heavy oil in water depths of 1,095 metres isn't really much to get too excited about.

The current Mizzen well is the fifth well drilled in the Flemish Pass. Back in 2003, Petro-Canada drilled a dry hole (Mizzen L-11) and previously Imperial Oil Limited had drilled dry holes at Baccalieu I-78 and Kyle L-11.

Currently there is only one other offshore rig on the east coast of Canada. But, unfortunately, the Aker GSF Grand Banks semi-submersible rig, also operated by Transocean, can only operate in water depths up to 457 metres.

More Canadians are becoming attuned to the laciness of this offshore regulator and the low liability cap that it allows industry to operate under. The east coast discount rate of \$30 million that was out of place when set 20 years is ever further out of date today. Unfortunately the Newfoundland Board didn't have the backbone to revise this rate upward before it approves Statoil Canada's Mizzen F-09 deepwater well.

Although the Newfoundland Board, which costs Canadian taxpayers \$7.7 million per year in operating grants, says that it judges each drilling well application individually, you can rest assured that at the top of the measuring stick lie Newfoundland jobs and Newfoundland content for any equipment. The possibility of a blowout is much further down the list.

For Statoil, the \$30 million liability cap means a hit of less than one-half of one percent of its market capitalization of more than \$93 billion. Bear in mind that this offshore liability cap doesn't contain discounts if the oil from a blowout doesn't wash ashore along Newfoundland's east coast.

Of note, the C-NLOPB never bothered to look at the environmental track record of the drilling applicant. If so, it would have noticed the Norwegian energy giant Statoil ASA has been found to operate with a poor environmental record in Alberta. In mid-August, the company appeared in an Edmonton courtroom for the third time since proceeding started in April regarding water violations at its Leismer oil sands operations. In total, Statoil operates 275,200 acres (1,110 square kilometers) of oil sands leases located in the Athabasca region of Alberta, northeast of Edmonton.

Provides false information

In February 2011, Alberta's environment ministry charged Statoil with 19 counts related to contravening its water licence and providing false and misleading information regarding water withdrawals at its Leismer steam-driven oilsands project near Conklin in 2008 and 2009. Leismer is the first development area in the large Kai Kos Dehseh project that will ultimately produce 220,000 b/d of bitumen. Kai Kos Dehseh is a joint venture between StatoilHydro Canada (60%) and Thailand's PPT Exploration and Production (40%).

In spite of this, the August appearance was adjourned with the next appearance set for November 21st at which time the Norwegians will have the audacity of talking about receiving a 'creative ruling' that will reduce the number

of charges it faces.

To place these missteps in order, the charges refer to acts that occurred one year after the Norwegians took over operatorship of the oil sand project. It will be interesting to see how this will play out on the company's web site, which proclaims that it uses the most environmentally recognized technology to recover oil sand and that it operates with a clear goal to ensure sustainable development and help improve the environment.

Norwegians are failing badly

Remember that it was only last year when an Alberta judge took Syncrude Canada Ltd. to the woodshed and told the company that its operational handbook needed a serious update. The judge ruled that Syncrude Canada was guilty of failing to properly protect waterfowl from its tailing ponds. That judgment goes back to an event on April 28, 2008, when 1,606 migratory ducks (mallards, buffleheads and goldeneyes) died after entering the company's Aurora Settling Basin.

Syncrude Canada ended up paying \$3-million penalty for the deaths of the ducks in one of its toxic tailings ponds. The company also apologized for the incident and recognized that it must do much better when it comes to protecting wildlife.

It wasn't the verdict that was the surprise, it was how unprepared the seven-company consortium had been to defend itself in that other court of worth – public opinion. Syncrude Canada was found guilty on two charges – one under the federal Migratory Birds Convention Act and the other under Alberta's Environmental Protection and Enhancement Act.

Unfortunately, the Norwegians are also failing badly in that same court of public opinion.

OTHER NEWS

Regardless of what games environmental activists were playing in Washington last month as they attempted to slow down oil sands production in Alberta, *Cenovus Energy Inc.*, operator, and partner ConocoPhillips are moving ahead with their development plans at *Christina Lake*. Last month, the company received approval from the Alberta Energy Resources Conservation Board (ERCB) for three expansion phases (E, F and G), with each development containing a capacity 40,000 b/d. When completed, this new production of 120,000 b/d will bring gross production at Christina Lake to 218,000 b/d. With this approval, Cenovus Energy will have gross production of 290,000 b/d either under construction or already approved by the ERCB. The production volume is in addition to the combined gross production capacity of 138,000 b/d that the company currently has at Christina Lake and Foster Creek. First production from Phase E is planned for 2014, first production from Phase F is planned for 2016 and first production from Phase G is planned for 2017. The Christina Lake operation is located in northeast Alberta, approximately 120 kilometres south of Fort McMurray. Begun as a pilot project in 2000, the operation is currently producing approximately 18,000 b/d from 19 wells. Christina Lake has more than 700 million bbls of proved plus probable reserves and 800 million bbls of best estimate economic contingent resources. The operation is being built at a cost of approximately \$22,500 per flowing bbl. At the same time, Cenovus Energy announced that it has commenced production at the Phase C portion of the Christina Lake development. Construction at this phase had commenced back in early 2008 and steaming on the first pad of eight wells began in May 2011. The Phase has 32 well-pairs and a capacity of 40,000 b/d will be reached by mid-2012. This is more than Phases A and B, which have capacities of 18,000 b/d each.

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Hide and Seek or confidentiality? We expect that it is somewhere in between as Enbridge Inc. filed, on August 23rd, with the National Energy Board (NEB), commercial agreements with third-parties supporting the building of the *Northern Gateway Pipeline Project*. However, no names were included on the shippers' list supporting the filing. The filing states that more than 80% of the pipeline space on both delivery systems (crude oil and condensate) in its proposed \$5.5 billion delivery system to the west coast are backed by firm service Precedent Agreements. But, the shippers haven't executed firm Transportation Service Agreements and the filed commercial agreements contain escape chutes. The shippers are believed to be a mixture of Canadian oil producers and Asian refiners. Last year, Sinopec International Petroleum Exploration and Production Company (SIPC), a wholly-owned subsidiary of China Petrochemical Corporation, confirmed that it would be a shipper and had advanced \$250 million towards the building of the system. Interestingly, ConocoPhillips sold its 9.03% interest in Syncrude Canada to SIPC last year for (US) \$4.65 billion. The Northern Gateway system is a proposed 525,000 b/d, 36-inch diameter, 1,177-kilometre oil export pipeline running from near Edmonton, Alberta, to Kitimat, British Columbia, and a 193,000 bpd, 20-inch diameter condensate import pipeline running from Kitimat back to Edmonton. On cost overruns, shippers will bear 75% of the costs up to a 25% overrun. Over a 25% cost overrun, the shippers bear a 50% portion. Enbridge will be seeking a 12% rate of return for tolling purposes for the Northern Gateway system, which will bear a 30% equity component and 70% debt. Shippers can select either 15-year or 20-year transportation terms.

In January 2010, the Canadian Environmental Assessment Agency and the NEB established a three-member Joint Review Panel to handle the project's environmental and regulatory review of the application that was filed on May 27, 2010. On May 5, 2011, the Panel issued Hearing Order (OH-4-2011), which commenced the formal public part of the application. Community hearings are to begin in January 2012 and final hearings to start in June 2012. Enbridge hopes to receive regulatory approval by July 31, 2013, and indicates that the earliest possible in-service date is 2017. But many believe that this will be just a pit stop in this controversy as it makes its way to the Supreme Court of Canada or until the federal government steps in by declaring the pipeline to be in the "national interest". Unfortunately, this project, leading too much needed market diversification for oil sands production, isn't going to be fully decided inside the course of an energy regulatory hearing. It will be decided in the arena of political opinion. But in spite of the filing of the commercial agreements, the opposition still remains at the ready for the battle. The project also includes a marine terminal at Kitimat with two ship berths and 14 storage tanks for oil and condensate. As it currently stands, ownership of the pipeline is 51% Enbridge and 49% shippers. However, Enbridge has granted certain First Nations a right to take a 10% interest, which would dilute Enbridge and the shipping group on a pro rata basis. In fact, the marine portion of this new market search will be the hardest part. As the oil industry found out six years ago, most people living along British Columbia's coast have a thing or two about oil tankers and drilling rigs – they don't like them. In fact, they don't want to see them, period.

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Late last month, the U.S. Geological Survey (USGS) released some eye-opening numbers for the *Marcellus Shale* Gas reserves contained in the Northeast Appalachian Basin. The USGS says that the region contains undiscovered, recoverable natural gas reserves in the order of 84 Tcf. The last survey done in 2002 recorded recoverable gas at 2 Tcf for the gas-rich formation underlying New York, Pennsylvania, Ohio and West Virginia. To add further weight to what has happened in the last eight years, the USGS also records the Marcellus shale estimated undiscovered natural gas liquid reserves (NGL) at 3,4 billion bbls. When the State of New York shortly opens up its lands for drilling, this estimate will grow. However, we are still at least two years away before any Marcellus Shale drilling takes place in the State of New York. The State has recently implemented a final Environmental Impact Statement that will place hydrofracing in the Syracuse and New York City watersheds (15% of the New York portion of the

Marcellus Shale) off limits. At best, it won't be until late 2013 before the dance over the comments coming from this Statement are in report form. But, taking data from 3,300 wells drilled in Pennsylvania in the last few years, the new survey suggests that Marcellus Shale gas reserves in the Pennsylvania area range from 43 Tcf to 144 Tcf and NGL reserves range from 1.6 billion bbls to 6.2 billion bbls. That comes to a growth rate of approximately 52% per annum. However, there is no concern that the USGS figures for the Marcellus are much lower than the Energy Department's estimate of 410 Tcf. The Energy Department concedes that the USGS are the experts and they're not. Thus, the Energy Department will now be running with the USGS data.

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Back up and running and resumption of Synthetic Crude Oil (SCO) sales have finally recommenced at the *Horizon Oil Sands Project* operated by *Canadian Natural Resources Limited* in northern Alberta. The company resumed production on August 16th at the facility, which had been shut down from a fire that occurred in the coker unit 222 days earlier on January 6th. First pipeline deliveries commenced on August 18th. At the end of August, the operation was running at full production SCO capacity of 110,000 b/d. Not surprisingly, the loss of production at the Horizon Oil Sands operation has played havoc with the company's production picture. Production during the first six months of 2011 averaged 561,359 b/d of crude oil equivalent, down 10.9% from production of 629,982 b/d of crude oil equivalent averaged in the first half of 2010. All that production loss came from the crude oil and natural gas liquids (NGL) side of the operation. First half of 2011 crude oil and NGL production was 353,433 b/d, down 16.8% from 424,757 b/d in the first half of 2010. So the history of Canada's fourth oil sands mining operation, which produced its first bbl of 34 degree API light, sweet synthetic crude oil on February 28, 2009, hasn't been exactly as planned on February 10, 2005, when the company's Board of Directors gave thumbs up to proceed with Phase 1 of the development.

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Finally, after 110 days the tide turned for a pipeline company that had been swimming against a sea of bad news since a major oil spill. *Plains Midstream Canada* (100%) received conditional approval from the Alberta Energy Resources Conservation Board (ERCB) on August 16th to resume operation of its NPS 20 Rainbow Pipeline. The 772-kilometre *Rainbow Pipeline* in Alberta consists of two main segments: a 470-kilometre, 20-inch line running from Zama to the Nipisi terminal where it joins to a 302-kilometre, 24-inch line running into the Edmonton area. The spill occurred on April 28th on the northern portion, north of Nipisi pump station, near the community of Little Buffalo and was shut down the next day. Fourteen days after receiving its conditional approval from the ERCB, Plains Midstream Canada reopened the line with a design capacity of 220,000 b/d. The pipeline's maximum operating pressure will be limited (75%), at least in the early days of resumption. In 2010, the line's capacity averaged at the rate of 187,000 b/d. During the time that the northern section was shut down for repairs, the company was shipping about 100,000 b/d on its 24-inch southern system from the Nipisi station into Edmonton. However, this approval to reopen the line comes with conditions. The company was required to dig up and check 10 sites on the Zama-to-Nipisi leg and it will have to submit monthly progress reports and attend monthly meetings with ERCB staff. Plains Midstream Canada also has to undertake weekly aerial surveys of the pipeline system. Under directions from the ERCB in early June, Plains Midstream Canada engaged Det Norske Veritas to conduct a comprehensive engineering assessment of the pipeline. This report, submitted to the ERCB on July 27th, found that the pipeline crack was formed at the time of installation of the weld-on sleeve in 1980 by a mechanism known as delayed hydrogen cracking.

However, the highlight of the last four months has been the attention that Plains Midstream Canada gave to keeping the public advised as to the status of the clean up. Just about daily, in the early afternoons, came status reports by email as to the mobilization, construction, containment and clean-up operations and the over 200,000

work hours logged. So it was a relief to read Rainbow Pipeline Update #81 dated August 30th: the pipeline was at last shipping crude oil. It is hoped that the Canadian Energy Pipeline Association will use this public disclosure exercise as a test model for some of its membership who are only too glad to press release good news but hide in the closet when bad news should be released. Many companies who had to use alternative methods of transportation for their production were affected by this shut down of the Zama-to-Nipisi leg (which was flowing at the rate of 75,000 b/d on April 28th), but none more so than Imperial Oil Limited and its operation at Norman Wells in the Northwest Territories, which was caught in a double squeeze. The company's Norman Wells crude oil production flows into the Enbridge Inc.'s 12-inch, 869-kilometre Norman Wells line (Line 21), with a capacity of 39,400 b/d, to Zama where it moves into the Rainbow Pipeline. But Imperial Oil couldn't shut down the production from Canada's most northerly producing field because the Town of Norman Wells, with a population of 850 people needs the natural gas that comes with the crude oil, for heating and cooking. Also, the Norman Wells pipeline system went out of commission after it sprang a leak on May 9th, which was originally reported as four bbls but was later confirmed to have leaked up to 1,500 bbls. The system went back into use on May 20th at a greatly reduced operating pressure. On August 26th, the NEB placed some operating restrictions on the system. For the record, the largest pipeline spill in Alberta occurred on December 5, 1980, in the Valleyview area, approximately 110 kilometres east of Grande Prairie, Alberta, on the Peace Pipe Line Ltd. The total volume spilled was approximately 40,000 bbls.

S&P/TSX COMPOSITE INDICES

	<u>9/1/11</u>	<u>8/1/11</u>	<u>9/1/10</u>	<u>52-week</u> <u>high</u>	<u>low</u>
<i>S&P/TSX</i>	12,768.70	12,945.63	11,913.86	14,329.49	11,617.81
<i>ENERGY</i>	284.84	310.41	272.28	370.75	259.58
<i>UTILITIES</i>	225.76	220.44	201.80	232.40	197.92

CRUDE OIL PRICES

(Monthly Average - 40 degree API - Edmonton)

	<u>8/11</u>	<u>8 Mo/11</u>	<u>1/11</u>	<u>8 Mo/10</u>	<u>8/10</u>
(C) \$/bbl	\$88.81	\$92.45	\$83.93	\$77.63	\$76.39

Source: Imperial Oil