New market, new attitude

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Oil production in Canada is increasingly being dominated by the trend away from conventional oil operations (which have been concentrated in the west of the country) and towards natural gas, oil sands development and the development of offshore sites in the east of the country.

Shell Canada Resources sold all its oil holdings in western Canada in 1999 and Petro-Canada has now followed suit and put all of its conventional operations up for sale. Suncor Energy also announced in March this year that it is seeking buyers for all of its conventional oil operations in western Canada in order to concentrate on oil sands and natural gas. ? Conventional oil no longer makes any sense for Suncor,? declared chief financial officer Michael O'Brien at the time.

The move towards oil sands production rather than conventional production has been driven by declining reserves. The majority of the country's conventional oil reserves lie in the Devonian Reef Fields, which were discovered in the late 1940s. Having been drilled consistently for nearly 60 years, new reserves in these fields are getting harder to find. Not only is the size of pools being discovered getting smaller, but the quality of crude being discovered is getting lower.

It is not, therefore, surprising that the large producers are turning their attention to oil sands ? which represents not only a far more plentiful supply of raw material (the site of Shell's new Muskeg River Mine contains twice the amount of bitumen as all the conventional oil reserves left in the entire state of Alberta) but rapidly improving methods of extraction. ?The long-term focus for large projects [in Canada] is natural gas, heavy oil and offshore,? confirms Chris Fong at RBC Dominion Securities' energy group. ?Conventional oil simply can't attract large syndicates any more.?

Oil sands already account for a far higher percentage of production in Canada than they do elsewhere. In 1998, of the country's 2.2 million barrel-a-day output, 570,000 barrels per day came from oil sands ? a full 25%. The percentage of global output that is accounted for by oil sands is 1%. The oil sands basin itself consists of bitumen (petroleum in solid or semi-solid form) mixed with unconsolidated sand. The bitumen is extracted mixed together with clay and water (most of which are removed at the point of extraction). The bitumen is extracted from open pit mines instead of having to be sourced from underground pools. It is then pumped to an upgrader where it is processed into synthetic crude oil. Alberta's oil sands deposits are believed to contain as much as 2.5 trillion barrels of bitumen ? 300 billion barrels-worth of which is deemed recoverable. The Athabasca oil sands are currently responsible for 25% of the country's oil production (around 500,000 barrels per day). Shell estimates that this will increase to 1 million barrels per day by 2010 ? or 50% of all Canadian production.

Exploitation of these oil sands has so far been the almost exclusive preserve of Suncor Energy and Syncrude Canada (a consortium of large oil companies). Syncrude produced 225,000 barrels per day from its oil sands reserves in 1999 and is now committed to a C$6 billion expansion these activities. Likewise, Suncor plans to plough an additional C$2 billion into its oil sands production, which generated 115,000 barrels per day last year. Known as the Millenium Project, Suncor wants to boost synthetic crude output to 450,000 barrels per day by 2008. Suncor is hoping to raise around C$100 million from the sale of its conventional oil activities, which will be put towards the cost of this expansion. Indeed, this year should see an explosion of activity in these oil sands reserves, as the large oil producers muscle in on a potential goldmine.

Alberta oil sands

The largest deal to date ? but one that is in the very early stage of gestation ? has been proposed by Canadian Natural Resources. The company announced in March this year that it is planning an enormous C$6.5 billion Alberta oil sands project to exploit oil sands deposits that it acquired from BP Amoco last year. The project will focus on the Mic Mac lease, which is situated north of Fort McMurray in the north east of the state. Canadian Natural chairman Allan Markin has said that he has yet to decide whether partners will be brought in to help fund the project, but the company will try to fund the development with cash flow from other projects. US-based Coke Oil is also planning a development is the area together with a consortium known as UTS. This development entails a tar sands mine with no upgrader ? the mine will extract blended bitumen of shipping quality. Mobil was planning a C$2.5 billion project as well, but pulled out in April 1999 citing depressed oil prices.

However, there is a big difference between proposed deals and signed deals. The only large project to be signed so far is Shell Canada's C$4.5 billion Athabasca Oil Sands project, which closed in December last year. This project will exploit a 6 billion-barrel bitumen deposit sited 30 miles north of Fort McMurray, the Muskeg River lease. The project cost is estimated at around C$4.5 billion, incorporating an open pit mine, an extraction plant, an upgrader located next to Shell's existing facility at Scotford (north of Fort Saskatchewan) and ancillary projects including a pipeline and two cogeneration facilities. Shell Canada has a 60% stake in the deal, with 20% stakes being taken apiece by Chevron Canada and newcomer Western Oil Sands.

Western Oil Sands itself was formed out of necessity when Australian mining conglomerate Broken Hill Proprietary (BHP) walked away from its 25% option in the project in 1999. BHP was more concerned with problems at home, but its jettisoning of the Athabasca deal left a team of 25 employees ? which had been studying the proposal for two years at a cost of C$180 million ? effectively redundant. However, reluctant to walk away from what they felt was a very attractive project, the 25 BHP personnel ? headed up by former president of BHP World Minerals Tom Winterer ? formed Western Oil Sands to step in and take 20% of the deal. Guy Turcotte, a leading Canadian oil industry figure and financier came on board as chairman and TD Securities was retained as financial adviser.

Shell Canada was happy for the fledgling company to step in to BHP's shoes ? believing that the team's knowledge of the deal meant that they were the best people to take it forward. It also meant that a significant delay to the project while a new partner was sought and brought up to speed could be avoided.

Development cost for the Muskeg River lease are put at C$1.8 billion and for the Scotford upgrader at C$1.7 billion. A 450 km pipeline, known as the Corridor Pipeline, is to be constructed between the two by BC Gas (estimated cost C$690 million), and the mine power plant will be constructed by Atco Group at a cost of C$254 million. Shell Canada has earmarked C$2.5 billion for the project ? nearly two thirds of its overall C$4.1 billion five year spending plan. In 2000 this will entail C$720 million in the project itself and C$200 million to cover modifications to its existing facility at Scotford to enable it to process synthetic crude. The Athabasca deal is the largest investment in Shell Canada's history.

Western Oil Sands was extremely successful in sourcing funding for its portion of the deal ? speedily raising C$402.7 million in committed and contingent equity and C$535 million in senior secured debt between its formation in mid-1999 and closure of the deal at the end of December that year. The C$535 million limited recourse term loan runs for 6 years and was co-arranged by Toronto Dominion, Royal Bank of Canada and Bank of Nova Scotia. It was issued in three tranches with the same tenor: C$385 million, C$100 million and C$50 million. The loan was sold to syndicate of predominantly domestic and European banks including Bank of Montreal, ABN, CIBC, A Quebec-based mutual life company, HSBC, National Bank, Alberta Treasury Branches, Dresdner Bank, Hypovereinsbank, Canada West Bank, Royal Bank of Scotland and Bank of Tokyo (Montreal).

Lead counsel to the banks in the deal was Canadian law firm McCarthy Trenault. Their team was headed up by Michael McIntosh. ?The cost issues involved in deals of this magnitude mean that limited recourse financing is not for the fainthearted,? he says. Clearly, global players such as Shell and Chevron do not want to incur the incremental cost of limited recourse debt (between 10bp and 25bp) and are in a position not to have to. ?Western Oil Sands is simply not in the same league,? he notes.

While the C$535 million loan was a limited recourse deal, technically it can be seen as full recourse as Western Oil Sands is a single purpose company and does not have any other business. But the presence of Shell and Chevron in the deal effectively removed the risk associated with a new and untested name. ?If your cashflow is depending on credits such as Shell it means that the risk is pretty low,? McIntosh explains.

Lower risk oil sands

The successful completion of Western Oil Sands' financing is an indication of the appetite for oil sands deal from investors. McIntosh believes that oil sands projects are much more acceptable to lenders because of the lower risks involved. ?Oil sands deals are more suited to project finance than conventional deals as there is less reserve and development risk,? he says. The risks are lower as there is already a well-defined set of reserves to exploit ? negating the need for the traditional ?hunt and search? process associated with conventional oil production.

The risk is, therefore, more akin the manufacturing or production risk. ?There is a well-defined cash flow and derivatives are increasingly used to take out the volatility. These are some of the most fungible products in the world,? McIntosh enthuses. Chris Fong at RBC Dominion Securities agrees. ?The only real risk with oil sands projects is price risk,? he says. ?There is no reserve risk. If conventional technology is used then completion risk is also minimised.?

This will be music to the ears not only of the many producers looking to expand into the sector, but to the many ancillary projects associated with the Athabasca development itself.

Firstly, the Corridor Pipeline project, under which BC Gas will construct the pipeline that will run between the Muskeg mine and the Scotford upgrader. The cost of this project is expected to be around C$690 million and a mandate to arrange funding is expected to be announced shortly. A list of three banks is understood to have been shortlisted: CIBC, Toronto Dominion and Royal Bank of Canada. While a co-arranging group is likely, CIBC should be in a strong position as it is BC Gas's relationship bank.

There is no confirmation as to whether the Corridor Pipeline project will involve any limited recourse funding. The Athabasca development will, however, also entail construction of two 170MW power plants ? one at the mine site and one at the upgrader. The power plant at the mine site will be constructed by Calgary-based Atco Power at a cost of C$245 million. Royal Bank of Canada is understood to have a strong relationship with Atco Power. Observers expect that these two cogeneration projects will involve some element of limited recourse debt.

Atco Power is no stranger to non-recourse financing as it was involved in one of Canada's most ambitious oil project financings to date.

The deal was the C$257.4 million financing of the 416MW Joffre cogeneration plant at Nova Chemicals' petrochemical manufacturing site in Alberta. This is the largest cogeneration plant in Canada, and the deal is also noteworthy as it was the first Canadian power plant with a merchant component to be financed on a non-recourse basis in the country.

The project, financing for which was signed off in early January this year, was sponsored by Atco Power and Nova Chemicals together with Epcor (Edmonton Power's parent). Nova will purchase 128MW of the plant's output, with the remaining 288MW being sold directly into the Power Poll of Alberta. Financing for the project was co-arranged by RBC Dominion Securities, WestLB and John Hancock Mutual Life.

The merchant portion of the deal accounts for a full 45% to 50% of the funding and was issued in two tranches: A C$100 million institutional tranche with a tenor of 20 years. The amortization schedule on this tranche is end-weighted, giving it an average life of around 16 years. The bank tranche was C$168 million in size and runs for 12 years with a 6.5 year average life. It was sold down to a lead managing group consisting of Abbey National, Alberta Treasury Branches, AIB Corp, Bayerische Landesbank, EDC Canada and NorddeutscheLandesbank. The balance of the funding was raised through a full-recourse 21-year term loan.

Unfamiliar merchant risk

The concept of merchant risk is a relatively new one for domestic lenders in Canada, and it was, therefore, quite a hard sell. ?The merchant aspect was quite a struggle,? admits Chris Fong at RBC Dominion Securities. ?We basically had to go down to the US to sell it.? Kevin Adams in RBC Dominion Securities' debt syndicate team agrees. ?There was an unfamiliarity with the product which was a problem,? he says. ?US banks and foreign banks were much more receptive to the whole idea.? Adams believes that there is still a long way to go in Canada before this type of risk becomes widely acceptable. ?Maybe now that Joffre has been done it might move the process forward, but it is still very new,? he says. Brian Vaasjo, Epcor's executive vice-president and chief financial officer, has been much more upbeat, stating that ?...this funding is a very positive sign for power project developers as it sets a good financing precedent for future merchant power projects.? It will be interesting to see whether a second such deal would be significantly easier to sell. ?The main problem that lenders have with the structure is simply that they aren't driving the bus,? muses Adams at RBC Dominion Securities.

In addition to oil sands, many people see natural gas as a strong growth area in Canada going forward. The country's northern territories have huge reserves and could be a rich source of deals. ?Gas prices (at C$3) are starting to approach a level where financings might be possible,? states Chris Fong, explaining that Canada's strong currency means that the price is even better at closer to C$4. ?Gas is the way forward,? agrees Greg Hickaway at Scotia Capital. Hickaway warns, however, that a large number of gas producers are publicly traded companies and may be less likely to raise funds through project deals.

But limited recourse deals have been done, such as the C$2.1 billion Alliance Pipeline transaction, which closed in 1999. This deal was the result of a consortium of local oil and gas companies deciding to set up an alternative to the TransCanada Pipeline. TransCanada announced in December last year that it plans to sell a large chunk of its oil assets to focus on core natural gas business. It plans to exit all of its midstream Canadian business and sell off its international Express crude oil pipeline system. It hopes to raise nearly C$3 billion to repay debt.

The Alliance Pipeline is the largest construction project in north America and is set for completion in October this year. The pipe runs from western Canada to the Aux Sable liquid processing facility near Chicago. Limited recourse financing for this deal was put together by co-leads Bank of Nova Scotia, Bank of Montreal, NatWest and Chase Manhattan.

Canada's offshore reserves have been and continue to be a good solid source of dealflow for project financiers. Two large deals ? Hibernia and Maritime and North eastern Pipeline has recently been closed, and Project Finance's north American oil and gas Deal of the Year for 1999 was awarded to a Canadian offshore transaction ? the Terra Nova Development. The project involves the exploitation of oil reserves in the Terra Nova oilfield off Newfoundland. The overall project cost was C$299 million and it was sponsored by Petro-Canada, Mobil Canada, Husky Oil, Norsk Hydro Canada, Murphy Oil, Mosbacher and Chevron Canada Resources. The Deal of the Year award went to Husky Oil's portion of the fundraising. This was a C$250 million fixed-rate asset-backed bond issued under rule 144a. It was thus faced with not only no proven reserves of oil but also considerable completion risk and no guarantee from Husky Oil. The bonds ? which have a maturity of 11.5 years and an average life of 6.6 years ? are full recourse to the assets of the Husky Terra Nova Partnership and non-recourse to Husky Oil. The deal was put together by CSFB in New York. It could pave the way for other offshore projects to explore the possibility of raising 144a funds as well.

The success of large deals such as these is good news for the smaller players as well. And, as with all structured markets, it is often the smaller players that have not only the necessity but the will to examine more innovative fundraising methods.

Traditionally conservative Canada is still some way behind its US and European counterparts in some sectors, but it is catching up fast. ?There has been a greater familiarity in Canada with limited recourse and off-balance sheet products over the last three years,? explains Michael McIntosh at McCarthy Trenault. ?There is a growing appetite for these types of deals.? McIntosh has seen particular growth in synthetic lease structures ? which were largely untouched by domestic entities five years ago. ?These deals are now coming through with reasonable regularity,? he explains, adding that they range in size from as small as C$25 million to as large as C$650 million to C$800 million. ?The larger deals typically involve a US affiliate, but over the last 12 months 75% of the synthetic leasing business I have seen involves domestic Canadian companies,? he claims.