**ANCHORAGE**

**Gas line economic?**

*By Kristen Nelson*

Econ One Research President Jeffrey Leitzinger told the Alaska Legislative Budget and Audit Committee June 14 that his firm’s analysis of the proposed North Slope gas pipeline project, and of the state’s preliminary fiscal interest finding on the proposed contract, show the project to be economic.

If there is an issue, Leitzinger said, it is that the North Slope producers proposing to build the line are exploration and production companies and want an E&P rate of return from a pipeline project, not a pipeline return, which is generally in the 11 percent to 12 percent range.

The state’s fiscal interest finding on the contract the administration has negotiated with project sponsors BP, ConocoPhillips and ExxonMobil, said a North-Slope-to-market natural gas pipeline project is competitively disadvantaged compared to other projects worldwide because of limited capital and high transportation costs.

Leitzinger said he disagreed, citing more than $120 billion of expected net flow in 2006 dollars to the producers from a line to Alberta, making the Alaska project one of the highest net-flow projects in the world and very attractive by any normal economic metric. The expected net present value is among the

**Group looking for oil and gas under west Anchorage**

*By Alan Bailey*

Two of the more intriguing lease purchases in the state of Alaska’s May Cook Inlet areawide lease sale consisted of a couple of tracts in the western part of the city of Anchorage. Bruce Webb, a member of the investment group that purchased one of the leases, talked to Petroleum News recently about the group’s intentions.

Anchorage lies on the northeast side of the prolific Cook Inlet basin and Webb said that Dan Donkel, a veteran Alaska lease holder and another member of the bidding group, has a map from

**Looking for Arctic partners**

*By Gary Park*

Changes are afoot in Canada’s northern regions, with two key operators inviting new partners to join them in exploring the Mackenzie Delta and Beaufort Sea.

Both Devon and a Chevron-BP joint venture say they are open to involving others to help push ahead with their programs.

In both cases, the response could determine when the next wells are drilled in a costly, challenging

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**BREAKING NEWS**

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5 **Thin project getting thinner:** Imperial stops government involvement in three months

8 **Going back to the future:** C$1 trillion in oil and gas could be extracted in western Canada by spending C$15 billion

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Econ One says it is, contends producers want more than pipeline return rate

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Devon, Chevron-BP JV hoping to continue Mackenzie-Beaufort exploration

Looking for Arctic partners
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# Alaska - Mackenzie Rig Report

**Alaska Rig Status**

### North Slope - Onshore

<table>
<thead>
<tr>
<th>Rig Owner/Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
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<tbody>
<tr>
<td>Doyon Drilling</td>
<td>Dreco 1250 UE</td>
<td>14 (SCR/CTD) Workovers H-30</td>
<td>BP</td>
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<td>Sky Top Brewater NE-12</td>
<td>15 (SCR/CTD) Kuparuk 11-127</td>
<td>ConocoPhillips</td>
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<td>Dreco 1000 UE</td>
<td>16 (SCR) Workover B-9</td>
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<td>ConocoPhillips</td>
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<td></td>
<td>TSM 7000</td>
<td>Arctic Fox #1 Stacked in Yard</td>
<td>Pioneer Natural Resources</td>
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### North Slope - Offshore

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<th>Rig Owner/Rig Type</th>
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<th>Operator or Status</th>
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<td>Oilwell 2000</td>
<td>33-E Moving</td>
<td>BP</td>
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### Cook Inlet Basin - Onshore

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<tbody>
<tr>
<td>Aurora Well Service</td>
<td>Franks 300 Srs. Explorer III</td>
<td>AWS 1 Nicolai Creek 1b workover</td>
<td>Aurora Gas</td>
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<tr>
<td></td>
<td>Kuupik</td>
<td>5 Plugging Swanson River SCL-42B-05 for abandonment</td>
<td>Unocal</td>
</tr>
</tbody>
</table>

### Mackenzie Rig Status

- **Canadian Beaufort Sea**
  - Seatankers (AKITA Equtak labor contract)
    - SDC CANMAR Island Rig #2
    - In cold shutdown at Faktor
      - Devon ARL Corp.

### Mackenzie Delta-Onshore

<table>
<thead>
<tr>
<th>Rig Owner/Rig Type</th>
<th>Rig No.</th>
<th>Rig Location/Activity</th>
<th>Operator or Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>AKITA Equtak</td>
<td>Dreco 1250 UE</td>
<td>62 (SCR/CTD) Stacked in Tuktoyaktuk, NT</td>
<td>Available</td>
</tr>
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</table>

### Yukon Territories Rig Status

**Northwest Territories**

<table>
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<th>Operator or Status</th>
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<tr>
<td>XTO Energy</td>
<td>National 1320</td>
<td>A Platform A C21A-23</td>
<td>XTO</td>
</tr>
<tr>
<td></td>
<td>National 110</td>
<td>C (TD) Idle</td>
<td>XTO</td>
</tr>
</tbody>
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![XTO Energy Logo]
Much ado about Arctic natural gas

Canadian Superior Energy enters fray as deadline on Petro-Canada bid for Canada Southern nears; others said to be interested

By GARY PARK
For Petroleum News

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ompetition for a bundle of Arctic natural gas assets has taken new twists and turns as Petro-Canada’s unsolicited offer for Canada Southern Petroleum winds down to its June 20 expiry date.

Offshore plays in Trinidad and Tobago and Nova Scotia have been dragged into the mix as Canadian Superior Energy, under remit of its Chief Executive Officer Greg Noval, has tried to seize the controls.

With Petro-Canada refusing to sweeten its bid, Canada Southern had suggested to its shareholders that better deals were in the offing, indicating as many as four “significant companies” might surface.

Chief Executive Officer John McDonald told Canada Southern shareholders at their June 8 annual meeting that other contenders have been invited to visit a data room, a process he said is "ongoing,” building optimism that a better deal will be tabled.

So far, only Canadian Superior, a junior E&P with a considerable history of legal and regulatory tangles and internal upheavals, has publicly declared its interest in the frontier assets.

It has floated a cash-and-shares offer it figures is worth upwards of C$130 million, estimating that it is 11 percent better than Petro-Canada’s all-cash offer.

In a statement, Noval built a case to Canada Southern shareholders around the virtues his own company has in the wings.

He said Canadian Superior is presenting Canada Southern investors with a “tremendous immediate opportunity” to benefit from his company’s land position in Trinidad and Tobago “where some of the most prolific natural gas wells in the world are located in proximity to Canadian Superior’s acreage” where two wells are scheduled for the final quarter of this year.

He noted that wells offsetting Canadian Superior’s Intrepid Block 5 (c) are producing 400 million cubic feet per day and BP has just started producing 800 million cubic feet per day in an area where the super-major has 15 of its largest 25 yielding wells in the world.

Noval said several majors, including Petro-Canada, Total, British Gas, Husky and Whitefish, a 1979 strike listed at 2.4 tcf.

Petro-Canada conceded obstacles — technological, financial, regulatory and political — stand in the path of developing such resources.

But the company is just as adamant that its shareholders that better deals were in the offing,

Nova Scotia a turbulent episode

Canadian Superior also tied its pitch to its 1.29 million acres offshore Nova Scotia, where it is the largest public holder of exploration land and its onshore oil and gas operations in Canada, including coalbed methane acreage in Alberta where it noted EnCana has been paying up to C$2 million per section for coalbed methane rights.

Nova Scotia has been one of Canada’s Superior’s most turbulent episodes after 50 percent partner El Paso refused to finance the testing of the Mainer I-85 exploration well — a C$10 million undertaking that generated a dozen press releases of a mostly upbeat nature during the drilling.

The fallout involved a spate of lawsuits in the U.S. and Canada, accusing the company of issuing “false and misleading” releases.

Canadian Superior ended a three-year working relationship in Fall 2004 by acquir- ing all of El Paso’s Nova Scotia holdings for an undisclosed amount, still confident that the play has the potential to turn the company from a bread-and-butter producer to a high-impact frontier operator.

Although Noval made no mention of Canadian Superior’s desire to add long- term Arctic prospects to its portfolio, company director Richard Watts said the appeal to his company is Canada Southern’s “great set of assets” in the Arctic Islands and Yukon.

He said Canadian Superior has been “watching” the properties for some time and saw Petro-Canada’s offer as the “cata- lyst” to make a second hostile run at Canada Southern.

The magnet is Canada Southern’s mixed bag of carried and working interests in seven of 16 significant discovery licenses in Canada’s Far North, two of which are rated among Canada’s top five gas discoveries.

The assets include Drake Point, a 1969 find that is estimated to contain 54 trillion cubic feet, Hecla’s 1972 discovery of 3.2 tcf and Whitefish, a 1979 strike listed at 2.4 tcf.

Petro-Canada, as the largest leaseholder in the region, said it wants to consolidate the scattered ownership and position itself as the strongest contender to develop the resources.

But the company is just as adamant that its offer for Canada Southern is fair and won’t be improved.

Petro-Canada concedes obstacles

From the outset, Petro-Canada has con- ceeded many obstacles — technological, fiscal and the outlook for commodity prices — stand in the path of developing such remote resources and insisted it has no see ARCTIC GAS page 7

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Mac gas line: Thin project getting thinner

Imperial Oil stops government negotiations to revise a budget being squeezed by hyper-inflation in construction sector

By GARY PARK
For Petroleum News

The Mackenzie Gas Project has collided with the looming realities of raging inflation to drop its nuclear pipeline and gas industry, forcing the proponents to call a time out in their discussions with the Canadian government on fiscal terms until they can complete a revised budget this fall.

“We don’t have a lot of confidence in the cost estimates right now,” Imperial Oil Senior Vice President Randy Broiles told reporters June 14.

While deciding to get drawn into guessing numbers, he left little doubt that the current projection of C$7.5 billion will rise.

Because the construction industry has changed so much in the past two years “it’s impossible to know what the new number is,” Broiles said.

Referring to what he called “the frothiness...in global conditions,” he said the Mackenzie project along with more than C$100 billion worth of oil sands ventures now on the table are being hit with a full spectrum of rising costs for labor, steel and equipment.

While the Mackenzie partners try to get a fix on where those increases — which have climbed 30 percent to 50 percent in the past two years and are expected by some analysts to rise a further 30 percent — “we have paused discussions with the government right now, to let us do the homework we need to on the cost side,” Broiles said.

But he said that was not the same as the halt in operational work ordered by Imperial in April 2005 to resolve problems such as the regulatory timetable and negotiations with aboriginal regions on access and benefits agreements.

Imperial had previously indicated it hoped the current negotiations would produce a result by mid-2006.

“Last year, we were saying we need to see a way through the hurdles of the Mackenzie,” he said. “We’ve got that help, so it’s not that sort of thing all.”

However, he conveyed a strong message that Ottawa may be expected to hike its contributions to the project, currently estimated at C$3 billion.

Reiterating a frequent theme from Imperial executives, Broiles said the project has been economically “thin from the beginning and with more cost pressure, that’s bad news.”

“So we have to finish that work and then we’ll know what we need to talk through with the government,” he said.

The cost spiral started in late 2004, when estimates were hiked from C$5 billion to C$7 billion. More recently, another C$500 million has been added.

Barge across top of Alaska

As well as reviewing the budget, Imperial is exploring cost-saving options, including the possibility of barging major components, such as a gas processing plant, across the top of Alaska to Inuvik in the Northwest Territories, rather than moving them in pieces along the Mackenzie River Valley.

Broiles said that has the “potential to claw back big savings.”

He said another alternative is extending the pipeline construction season to three summers from two, which would push the start of production at 1.2 billion cubic feet per day beyond the current target of 2011.

One of the few to attempt a new cost forecast, Tristone Capital analyst Chris Theal said earlier this month the project could cost C$59 billion, although he said higher gas prices by the completion date would leave the return on investment largely unchanged.

He suggested to the Globe and Mail that Imperial’s decision to announce a break in the government negotiations might be mostly a bargaining ploy.

To attempt to negotiate better leverage from the government is a “great tact,” Theal said.

BP CEO sees long-term drop in oil prices

Oil prices could drop to about $40 a barrel in the medium term as new supplies are found, and might fall even further in the long term, the chief executive of BP PLC said, according to an interview published June 12.

BP CEO Lord Browne cautioned that “we cannot really predict how much oil is found” because large new oil fields are still being found and that regions such as West Africa have significant oil supplies, the report said.

Browne referred to sources such as Canada’s oil sands also can be tapped profitably, adding that production costs still amount only to a small proportion of the price.

“It is very likely that, in the medium term, prices will stand at about $40 on average,” Browne was quoted as saying. “In the very long run, even $25 to $30 are possible.”

Oil prices have soared recently, pushed up notably by tensions over Iran’s nuclear ambitions. Iran said June 11 it had accepted some parts of a Western offer aimed at getting a stop to its nuclear program, but others disagree.

Light sweet crude for July delivery was up 36 cents June 12 to $71.99 a barrel in electronic trading on the New York Mercantile Exchange.

WASHINGTON, D.C.
Bush nominates Pearce as Alaska natural gas pipeline coordinator

Former state Senate President Drue Pearce has been nominated by President George W. Bush to be federal coordinator of an Alaska natural gas pipeline project.

Congress ordered the creation of the job in 2004 as part of legislation designed to speed federal review of the proposed pipeline.

Pearce now is senior adviser to the secretary of the Interior for Alaska affairs. Pearce will work until one year after the completion of the natural gas pipeline project, according to a White House announcement.

The 2004 law calls for the coordinator to oversee the “expeditious discharge of all activities by federal agencies with respect to an Alaska natural gas transportation project” and ensure that they follow the direction of Congress.

Coordinator can veto agencies

The act states that the coordinator will be able to veto any agency’s attempt to attach a “term or condition,” short of those required by law, if the coordinator determines that it “would prevent or impair” the rapid construction or expansion of the line.

The law directs the federal coordinator and the State of Alaska to set up a joint surveillance and monitoring agreement like the one used for construction of the trans-Alaska pipeline in the mid-1970s. The agreement must be approved by the president and the governor of Alaska.

Pearce, a Republican, was elected to the Alaska House of Representatives in 1984 from Anchorage and to the Alaska Senate in 1988. She served as Senate president twice.

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The alaska act of 1980 is the primary legislation for the division of oil and gas. It was passed in 1980 to provide a framework for the management and development of the state’s oil and gas resources. The act created the Division of Oil and Gas within the Department of Natural Resources and established policies and procedures for the administration of oil and gas leases. The Division of Oil and Gas is responsible for regulating oil and gas activities in the state, including the allocation of leases, the issuance of permits, and the enforcement of regulations. The act also establishes the Alaska Oil and Gas Conservation Commission to provide technical advice and guidance to the division.

The act states that the Division of Oil and Gas shall, among other things, regulate the development and production of oil and gas resources, protect the public health, safety, and welfare, and provide for the equitable and efficient use and development of the state’s oil and gas resources. The act also authorizes the division to enter into agreements with the federal government to promote the development of oil and gas resources in the state. The act contains provisions for the allocation of revenues from oil and gas leases, including the establishment of a severance tax and the distribution of lease bonuses.

The act also contains provisions for the establishment of a state oil and gas pipeline, which is a major part of the state’s oil and gas development strategy. The act authorizes the division to designate a pipeline route and to enter into agreements with the federal government and other states to develop the pipeline. The act also contains provisions for the establishment of a natural gas processing plant, which is necessary to ensure a reliable and efficient supply of natural gas to the state. The act also contains provisions for the establishment of a state oil and gas refinery, which is necessary to ensure a reliable and efficient supply of refined petroleum products to the state.

The act also contains provisions for the establishment of a state oil and gas transportation system, which is necessary to ensure a reliable and efficient supply of oil and gas products to the state. The act also contains provisions for the establishment of a state oil and gas research program, which is necessary to ensure a reliable and efficient supply of oil and gas products to the state. The act also contains provisions for the establishment of a state oil and gas educational program, which is necessary to ensure a reliable and efficient supply of oil and gas products to the state. The act also contains provisions for the establishment of a state oil and gas emergency response program, which is necessary to ensure a reliable and efficient supply of oil and gas products to the state.
Former DNR officials: Contract a bad deal

Irwin, Rutherford say state is subsidizing the North Slope gas pipeline to the tune of $13.25 billion in contract governor negotiated

The proposed gas fiscal contract is a bad deal for the state, former Department of Natural Resource officials Tom Irwin and Marty Rutherford told Petroleum News following a Commonwealth North presentation on June 9 in Anchorage.

Rutherford, a former DNR deputy commissioner, said they believe the state should back away from the Stranded Gas Development Act under which the administration of Gov. Frank Murkowski negotiated the gas fiscal contract.

"It was a law that was passed when the price of gas was very low and its time has quit in protest," Irwin said. He said the economics on a bad deal is simple: "I am strongly and absolutely convinced this is an economic project" (without incentives). The DNR team working on the project reached the same conclusion, he said, as did Eon One, a firm hired by the Legislature to look at the project.

Read the contract, he urged the audience, and then approach it from a business perspective.

He said his conclusion is that the companies got a good deal, but not the state.

"The state gets no deal," Irwin said.

First, the producers get out of the contract in 60 days — the state has no way out of short of proving that the producers did not meet a diligence standard to move ahead with the project. Studying gas prices could meet that test, he said. "It’s a good deal for them. We have no deal."

The contract also removes the state’s sovereign authority, he said. "Would you, with your company, remove your authority in a contract?"

Irwin said he believes that giving up the state’s option to take royalty in kind or royalty in value is “an absolute mistake” and creates significant cost and risk issues for the state, putting the state “in a position of weakness in getting capacity in the lines” and in competition with the best marketers in the world to sell the gas. "We’re now told, he said, that another company will sell the gas for us. But we don’t pay for that now, and we get the highest price any of the sellers gets.

And if the state is going into this as a business, Irwin said, Alaskans need to see the real costs, “not the political feel-good” costs. He said that approximations it appears a higher gas price is used in discussing revenues — without costs deducted — and a lower price when discussing supports needed for the project. Business parties use a range of prices, he said.

The facts need to be out on the table, he said, so everyone can answer the question: “Would you sign this if it was your business?”

Rewrite of state’s position

Rutherford said there are more than incentives in the contract. "This contract is a total rewrite of our entire oil and gas relationship with the producers," turns the existing oil and gas leasing program on its head and “largely surrenders the power of all three arms of government, our sovereign powers, to the producers.

The Legislature loses its power to tax the producers for up to 45 years; the “executive branch loses its right to manage and regulate the producers’ oil and gas leases and the ability to ensure those leases are adequately and appropriately developed” for up to 45 years, and the “judicial branch loses the ability to oversee the contract enforcement for up to 45 years.”

Fifty-four years is a long time, “and that alone, in my mind, is an unacceptable risk. Nobody thought that when … the ELF (economic limit factor on the state’s production severance tax) was passed 15 years ago that we were implementing a flawed taxation structure on our oil and gas leases. And yet, within 15 years, that’s what we did,” he said.

The period of time the contract is locked in “is far too great a risk for us to accept,” he said.

The cost of contract subsidies

Rutherford said the contract sets up a system that is “a total destruction of our normal, competitive environment” for oil and gas leasing, allowing the producers to lock up 500 leases on the North Slope for the term of the contract. “For 45 years, if they meet that weak diligence standard … this does not require building a pipeline or doesn’t require significant investment into a pipeline.”

The state also loses its ability “to ensure that leases are developed in a timely manner should they be economic,” he said, and creates a two-class system that discourages investment by companies who don’t have these advantages.

Rutherford said Eon One has found that with no upstream business and the producers owning 100 percent of the project under the current fiscal system, if natural gas sells for $4 per million BTUs, the producers have a 17.2 percent rate of return; at $5, it’s 20.4 percent. She said this compares to a 15 percent rate of return oil companies generally use as a benchmark.

Then there is a $13.25 billion cost to the state to sign the contract, “independent of its own investment in the pipeline,” Rutherford said, which said at a $4 gas price is a direct subsidy to the producers, independent of the state’s ownership position, worth “over half the value of the state gas.” At $3 a gigajoule, he said, the best case is that the state is writing a check in order to produce their gas.

Compare that to the status quo, she said: If the price of natural gas falls below the transportation cost — but the state is taking its gas in value, rather than in kind — “we don’t get a check, we pay zero, but we don’t actually receive revenue.”

The risk at low prices is one that would alarm any company, she said.

Upstream cost allowance: $5.45 billion

The $13.25 billion comes from several subsidies, the first of which is the upstream cost allowance.

The state made “a bad decision” in 1980, Rutherford said: it agreed to pay upstream costs it was not obligated to pay under its leases on royalty oil and gas at the Prudhoe Bay field. Later court decisions confirmed the state did not need to pay these costs, but in 1980 it agreed to pay them to accelerate a royalty in kind sale for Prudhoe Bay oil.

The contract expands that payment across the North Slope, she said, not just for royalty gas but for all of the state’s gas.

Rutherford described the contract as “a repeat on a much larger scale of what happened in 1980,” a mistake, she said, that has already cost the state $2 billion on oil alone.

The upstream cost allowance in the contract, less what the state agreed to pay at Prudhoe Bay in 1980, is a subsidy of $5.45 billion. It is the largest fiscal subsidy in the life of the contract, she said.

Upstream credits: $4 billion

The proposed production profits tax involves a subsidy of another $4 billion, she said, with credits against operating costs and capital costs in the field, even though the state doesn’t get a profits tax on gas, just a flat 7.25 percent of the tax taken in kind. Once you net out the royalty share it’s actually 6 percent.

Although the state gets no profits tax from gas, “we still pay all those development costs,” she said. "And because there is a credit, a "no upstream uplift", it’s a subsidy to the state in terms of its percent," that credit is worth about $4 billion.

Rutherford said the $4 billion is based on "very conservative capital costs on the upstream. It may be far greater than that ... in which case it could be "a much higher number."

She said gas that needs to be developed for the project includes Point Thompson and the National Petroleum Reserve-Alaska, as well as other fields, and will require significant capital investment in upstream gas.

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OFFICIALS

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development. The state would get less gas than it would under the present system, “where it makes zero investment,” but through its credits would pay for 40 percent of the development.

Midstream pipeline and gas treatment plant: $2 billion

The 100 pages recently added to the contract include a 35 percent credit for upstream pipelines leaving the unit boundaries and going to the gas conditioning plant, and a 35 percent credit for the gas conditioning plant, Rutherford said.

Those costs will include a big gas pipeline from Point Thomson and as many as a dozen other pipelines to move the additional 30 trillion cubic feet of gas needed, she said.

“We hope they get built,” Rutherford said. “But under this contract the state pays 35 percent in direct cash credit to the producers for the cost of those lines. Then on top of that we have agreed to pay 20 percent of that infrastructure as an owner.”

Rutherford said what it comes down to is the state pays 48 percent of the cost and gets 20 percent ownership in the midstream pipelines and the gas treatment plant, which has an estimated cost of $2.6 billion to $2.8 billion. By paying 48 percent of the costs and only having 20 percent of the ownership the state bears “far more proportional cost overrun risk than any of the producers,” she said.

The $2 billion midstream subsidy is independent of the state’s 20 percent investment as an owner, she said.

Processing subsidy: $440 million

The state will also pay a processing subsidy, Rutherford said.

continued from page 4

ARCTIC GAS

Plans in place to develop the Arctic

It is said studies of Arctic gas have generally been limited to the Drake and Hecla fields because others are “remote, small, subject to harsh conditions and are not thought to be viable on their own.”

Petro-Canada said there is “significant uncertainty” surrounding the technical and economic prospects of Arctic resources, adding it believes Canada Southern’s claims to hold 927 billion cubic feet of marketable gas are too high.

Canada Southern, 95 percent of whose shareholders are believed to be U.S. residents, is adamant that Petro-Canada’s bid doesn’t properly value the Arctic interests. McDonald told the annual meeting that an announcement of Arctic development plans from a major company is “very near,” without disclosing more details.

However, company Chairman Richard McGinity conceded that Canada Southern, with only six employees, is in no position to finance development of the fields.

He said valuing the assets is not easy when the future of the Arctic is so uncertain.

“It’s difficult for shareholders and it’s a challenge for their elected directors. It’s not simple,” he said.

In one of the few attempts to forecast a development schedule, the Canadian Energy Research Institute has concluded that Arctic gas could be produced economically in 2014, using liquefied natural gas or gas-to-liquids technology.

But even if that date were realistic, it “won’t have those options.

The state is a disadvantaged minority owner in a system where it doesn’t control the upstream.”

Under the present system if the state takes royalty-in-kind gas it takes ready to go into the pipeline. And that’s not how it comes out of the ground, she said. Prudhoe Bay is in a field with some H2S, hydrogen sulfide, and a lot of water and it “costs money to remove those products,” Rutherford said. As part of the state’s lease agreements, in exchange for taking only 12.5 percent royalty, the state does not pay to remove and dispose of those products.

The cost to remove them isn’t in the contract, it will have to be negotiated. There’s another cost: the liability of taking the gas includes the “physical liability to move it,” which means insurance and liability issues, she said.

Conservatively it will cost the state some $440 million over the life of the contract, for something the state now gets for free.

Selling the gas: $1.4 billion

Since the state will take its gas in kind, rather than in value, it will have to sell the gas. And it loses the “higher” of it when it took gas in value and the producers sold it — and delivered to the state a check reflecting the highest value of any of them got.

It was another compromise the state made for its 12.5 percent royalty, Rutherford said.

So what will it cost to sell the gas? She said she’s heard the producers talk about half a cent to market it. “That’s ridiculous: You can’t even cover your insurance liability for that and the DNR looked hard at those marketing costs,” Rutherford said.

“And we used outside experts,” she added.

The equivalent of having producer marketing and skill, and the value of the “higher” of provision came to about $1.4 billion, Rutherford said.

Other costs and risks

The subsidies add up to $13.25 billion, she said: $5.45 billion in upstream cost allowance, $4 billion in midstream pipeline and gas treatment subsidies; $2 billion from the 35 percent credit; $440 million for the processing; and $1.4 billion for marketing.

But there are other costs and risks the state wouldn’t bear if it took its gas in-kind.

Rutherford said the big one is the take-or-pay capacity the state will have in the gas pipeline over 25 years or so, whatever the pipeline sets for firm transportation commitment. If the state doesn’t have enough gas, it still pays the transportation fees, if it has too much gas, “it’s a distressed seller on the slope and has to find a buyer on the North Slope.” He characterized the protections in the contract as “weak” and said “they don’t really work.”

The exposure over the life of the contract is billions of dollars, Rutherford said. There are inefficiencies in any system, and the state will have some 900 million cubic feet a day of gas to deliver to the pipeline. “So even if you’re only 10 percent inefficient (in the slope pipelines and the gas processing facility) on this, there are $3 (billion) or $4 billion … of risk that we’re going to bear there.”

That’s because the state won’t be able to tell the producers to produce more or less gas.

Irwin said he’s heard many times that the state is getting into the gas pipeline so it can be like the producers. “We will never be like them: … We don’t own any wells, we don’t own any valves, so do not bury the story we will be like them.”

The producers, he said, have flexibility: they can expand the field if they don’t have enough gas; they can trade reserves; for a short time, they can allow one producer to over or under produce. The state, he said, doesn’t have those options.

“What happens is the state is a disadvantaged minority owner in a system where it doesn’t control the upstream.”

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A joint industry-government study estimates that an investment of up to C$1 billion a year for 15 years could apply new technology to retrieve 6 billion barrels of oil and 22.5 trillion cubic feet of non-associated natural gas that has been left in the ground by earlier generations of Western Canadian producers.

The C$1 trillion treasure trove (based on today’s commodity prices) doesn’t need rocket science to raise production of discovered reserves in the region to 36 percent from 27 percent. The study is the result of a 15-month Petroleum Technology Alliance Canada and EnergyINet, a joint partnership that is working to accelerate the development and deployment of advanced energy systems and technologies.

Technology alliance chief executive officer Michael Raymont told reporters the answer lies in applying technology that is already available. The report, Ramping Up Recovery: A Business Case for Increased Recovery of Conventional Oil and Gas, cost C$960,000, including contributions from the Alberta, British Columbia and Saskatchewan governments and many firms.

As the title conveys, the focus was on the mainland of Canada’s production for the past 60 years and paid no attention to the oil sands or coalbed methane. EnergyNet president Eric Lloyd said the potential bonanza can be exploited without any royalty or tax incentives, noting that it might be needed to reduce the risk of testing new recovery methods.

He said technology has the potential to “significantly increase our energy production to meet the world’s growing demand for energy.”

Raymont said the research has generated important information “that can help us better target our activities and research and development technology so that we can all share significant benefits from energy sources we have been unable to recover.”

Lloyd said the key lies in more engineering than basic discovery, with a reliance on the use of advances in mapping geological reservoirs, the handling and management of “produce water” from wells (currently about 12 barrels of brackish water for every barrel of oil produced), drilling methods and the injection of carbon dioxide into reservoirs.

He said a steering committee will be established to press for action of squeezing more from wells that date to the beginnings of the Western Canadian industry in the 1950s. The proprietary information is available only to companies who participate in the two-year research effort.

The agency said the growth in world petroleum consumption has slowed because of higher prices, but projected consumption growth remains strong at 1.7 million barrels per day in 2006 and 1.9 million barrels per day in 2007. The agency said the growth in world petroleum consumption has slowed because of higher prices, but projected consumption growth remains strong at 1.7 million barrels per day in 2006 and 1.9 million barrels per day in 2007.

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**INTERNATIONAL**

EIA expects $68 WTI spot price ’06-07

The U.S. Department of Energy’s Energy Information Administration expects the West Texas Intermediate crude oil spot price to average $68 in both 2006 and 2007, the agency said in its June short-term energy outlook issued June 6.

It projects lower natural gas prices the rest of this year compared to 2005, with a 2006 Henry Hub spot price average of $7.74 per thousand cubic feet, down $1.12 from the 2005 average. “For 2007, the Henry Hub average price will likely move back up to average $8.81 per mcf, assuming sustained oil prices, normal weather and continued economic expansion in the United States,” EIA said.

U.S. natural gas consumption is projected to fall some 0.9 percent below 2005 levels this year and then increase by 3.8 percent in 2007.

There was a 2.7 percent drop in domestic natural gas production in 2005, largely due to hurricane-induced disruptions in the Gulf of Mexico; production is expected to increase 0.7 percent in 2006 and 1.2 percent in 2007. Total liquefied natural gas net imports are expected to increase from 631 billion cubic feet in 2005 to 710 bcf in 2006 and 930 bcf in 2007.

As of May 26, working natural gas storage was estimated at 2.243 trillion cubic feet, 477 bcf above a year ago and 706 bcf above the five-year average.

Consumption growth has slowed

The agency said the growth in world petroleum consumption has slowed because of higher prices, but projected consumption growth remains strong at 1.7 million barrels per day in 2006 and 1.9 million barrels per day in 2007. Most of that growth will be met by non-Organization of Petroleum Exporting Countries’ production and shortfall will be met by an increase in OPEC production or drawdown of inventories.

“Because of only limited surplus capacity throughout the forecast period, continued economic expansion in the United States,” EIA said, “will require that consumption growth remains strong at 1.7 million barrels per day in 2006 and 1.9 million barrels per day in 2007.

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**W E S T E R N C A N A D A**

BP: Election may slow gas pipeline project

By MATT VOZ

The Associated Press

BP executive with BP Exploration (Alaska) Inc. says that a new governor is elected this fall without legislative approval of a natural gas contract, those contract negotiations may have to start over, reported Radio Kenai.

John White, senior project manager of BP’s Alaska Gas group, told the Soldotna Chamber of Commerce on June 13 that could mean a three-year delay of the North Slope gas pipeline.

Gov. Frank Murkowski’s contract proposal with BP, ExxonMobil and ConocoPhillips is out for public review. The contract would set long-range tax and royalty terms between the state and three oil companies who propose building the gas pipeline. BP spokesman Daren Beaudo said White’s comments were not an endorsement of Murkowski and that BP does not endorse any candidate.

Beaudo said an agreement was reached after three years of working with the Murkowski administration and the company would like to proceed under that deal. White was in Soldotna to drum up support for the contract, which must be approved by the Legislature to take effect but which does not guarantee construction of a pipeline.

Murkowski, the Republican incumbent, faces challenges within his own party from former Wasilla Mayor Sarah Palin and Fairbanks businessman John Binkley.

Palin supports a competing pipeline proposal to build a line from the North Slope to Valdez, where the gas would be liquefied and shipped to the West Coast. Binkley says Murkowski’s contract proposal with the oil companies is flawed but fixable and that he would get rid of the 30-year freeze on the companies’ oil taxes that Murkowski proposes to include.

The main Democratic challengers, former Gov. Tony Knowles and Rep. Eric Croft, also have strongly criticized Murkowski’s contract proposal with the companies.

The Legislature did not pass two key bills this special session that would set up a ratification vote of the contract. One would have changed the state’s production tax system to one based on the net profits of oil companies’ Alaska operations. The provisions of that bill were to be inserted into the contract. The Legislature also adjourned without amending the state’s Stranded Gas Development Act to give Murkowski the authority to negotiate oil taxes as part of a gas pipeline contract and to lock in those terms for multiple years.

The primary elections are Aug. 22. The general election is Nov. 7.

**A L A S K A**

BP’s Alaska bonanza can be exploited without any royalty or tax incentives to the oil sands or coalbed methane. Canada’s production for the past 60 years and paid no attention to the oil sands or coalbed methane.

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Willie's way on the highway

Ethanol sparks interest across North America, boosted by environmental concerns and Bush's drive to lower Middle East oil imports

By GARY PARK
Petroleum News

If you want to stay on the road you might consider hitching your wagon to Willie Nelson's promotion of biofuels. The country crooner is putting his money where his mouth is by manufacturing and selling “BioWillie,” his own brand of alternative fuel.

For Nelson it's a chance to convert U.S.-grown vegetable oil seeds into a clean-burning replacement for diesel fuel, both giving a future to family farmers and lending a helping hand to the environment.

A U.S. Department of Energy study concluded that the production and use of biodiesel slashed carbon dioxide emissions from the use of petroleum diesel by 78.5 percent.

Natural Resources Canada has calculated that a liter of 10 percent ethanol blend can lower greenhouse gas emissions by up to 5 percent compared to a liter of gasoline.

It's a trend that has already made solid gains in the U.S. and that Canada is starting to embrace.

Ottawa in May launched a summer of negotiations with provincial governments that it hopes will see renewable fuel levels in Canadian gasoline rise from 0.5 percent to 5 percent by 2010. Environment Minister Rona Ambrose said there is a “successful will to move forward,” while agreeing that the target is ambitious.

For her and the government of Prime Minister Stephen Harper it is a key element in their determination to develop a made-in-Canada climate change strategy, further undermining their commitment to the Kyoto Protocol.

The Canadian Renewable Fuels Association said that in addition to incentives the challenge will be to introduce common standards across Canada.

More ethanol needed

The obvious challenge is to hike production of ethanol — currently about 100 million liters a year from five major plants and targeted at 650 million liters by 2010 based on projects now in the works.

Even that increase will fall far short of the 1.4 billion liters the industry estimates will be needed to achieve the 5 percent goal.

In comparison, the U.S. production capacity last year was 15 billion liters from 101 plants (with another 32 under construction) prompted by Energy Policy Act requirements for U.S. ethanol production to reach 28 billion liters by 2012.

It's a all pick-me-up for U.S. corn farmers, who have relied for years on annual federal subsidies of $3.6 billion to offset losses, and have pointed to a liter of 10 percent ethanol blend of ethanol in all fuel sold in the province; Manitoba has a law requiring that at least 40 percent of vehicle fuel be blended with 10 percent ethanol; and Ontario and Quebec are working on two plants totaling 530 million liters of capacity last year, allowing them to defer corporate income taxes.

That has changed dramatically now that President George W. Bush has ordered a huge hike in ethanol use in his drive to reduce Middle East oil imports by 75 percent over the next 20 years, lifting corn futures to $2.55 per bushel from barely $2 over the winter.

If all of the targets are achieved, the U.S. is expected to burn 15 billion gallons a year of ethanol by 2015.

Leading the way in Canadian production are Husky Energy, which expects to have two new facilities (one each in Saskatchewan and Manitoba) turning out a combined 260 million liters by late 2007, and Commercial Alchohols, which is working on two plants totaling 530 million liters in Ontario and Quebec over an indefinite number of years, adding to its current output of 145 million liters.

But Commercial Alcohols Vice President Bliss Baker said setting a target is not enough.

He said the ethanol sector wants the Canadian government to offer incentives along the lines of those provided to oil sands operators to reduce the capital costs of expanding the processing capacity for biofuels.

The oil sands incentives allow companies to write off all of their upfront costs in a year, allowing them to defer corporate taxes.

The Canadian Renewable Fuels Association said that in addition to incentives the challenge will be to introduce common standards across Canada.

Currently, Saskatchewan requires a blend of ethanol in all fuel sold in the province; Manitoba has a law requiring that 85 percent of gasoline sold in its jurisdiction be blended with 10 percent ethanol; and Ontario offers tax breaks to producers of blended fuels and has pledged to have all gasoline contain 5 percent ethanol by 2007.

Ethanol producers hit the stock market

Ethanol is fast becoming one of the hottest prospects among investors in the United States.

The leading producer, Archer Daniels Midland, is already a publicly traded company, World Energy Energy hit the market earlier this year, allowing its firm to initiate coverage of the market. Since several major U.S. refiners have started phasing out the gasoline additive MTBE, methyl tertiary-butyl ether, the thirst for ethanol is rising faster than U.S. corn-ethanol producers can respond.

In parts of the United States ethanol is fetching as much or more wholesale as the retail price, which pushed fuel alcohol for blend-stock to $2.65 per gallon earlier this spring.

Brazil is forecast to produce 16 billion liters of sugarcane-based ethanol in 2006, up 600 million liters from last year, but its own domestic consumption will cut into exports.

Some traders have estimated that Brazilian demand, where ethanol makes up 40 percent of vehicle fuel, could slash exports to 1 billion liters this year from 2.4 billion in 2005 — a prospect that boosted ethanol pump prices by 14 percent in March alone.

Against that backdrop, the spot price of New York Harbor ethanol climbed to $4 a gallon in early June from $3.30 a year earlier.

Hawkeye, in its IPO filing, said it believes the U.S. ethanol industry has insufficient capacity to meet current and anticipated demand, projecting the market for oxygenates, including ethanol, will surpass 6 billion gallons within a few years.

Commercial Alcohols, Canada’s largest ethanol maker, is not preparing an IPO yet, despite growing interest from investment banks over the past two years, but Vice President Bliss Baker said all options are on the table.

He rejected any thought that the company might be missing out on a hot market, contending that the interest in alternative fuels is not about to fade.

Similarly, other Canadian ethanol companies, Pound-Maker Agventures of Saskatchewan and Permolex of Alberta, are neither ruling out, nor openly pursuing an IPO.

The Canadian Renewable Fuels Association said that in addition to incentives the challenge will be to introduce common standards across Canada.

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Gas overhang a threat, says NEB

Canada’s National Energy Board sees storage space running out by late summer, pushing prices down, triggering possible shut-ins

By GARY PARK
For Petroleum News

Canadian natural gas producers may be forced to scale back production by late summer if North American storage space reaches capacity for the first time, driving down commodity prices, said the National Energy Board.

In its inaugural summer outlook, the federal regulator said refilling storage facilities is one month ahead of schedule and, unless that pace changes, the “overhang” could drive prices to US$5 per million British thermal units — the lowest point since September 2004 and 16 percent below current futures prices.

Even worse is a growing sense of gloom among some Canadian analysts that junior producers carrying high levels of debt could be pushed over the brink if their capital spending outpaces their cash flow after a year of watching record levels of activity drive up the costs of drilling and other services by 50 percent.

Rattled by last winter’s dive in commodity prices, the North American natural gas sector is worried by a series of sign posts that are pointing in the wrong direction. But not everyone is reaching for the panic buttons.

The summer is forecast to be cooler than last year, lowering the demand for gas-fired electricity to run air conditioning systems, while gas storage systems may hit capacity the fall, laying the groundwork for a price slump around mid-September.

Ken Yeasting, a director of Cambridge Energy Research Associates, told a Calgary conference earlier in June that because there is insufficient storage space to absorb all of the gas available for injection there is likely to be a “sharp and swift drop in spot gas prices” unless summer temperatures sour or hurricanes cause significant supply disruptions.

CERA is predicting that early fall prices could drop from recent levels of just under US$6 per million British thermal units to $5, forcing some high-cost producers to sell at a loss for a period.

But Yeasting said that if prices drop towards $5, gas-fired power generation could displace coal-fired generation, creating additional gas demand and thus support prices and “rebalance the market.”

He said coal-fired plants likely to pay the price are older, inefficient eastern U.S. facilities that burn high-cost Appalachian coal without emission control equipment.

The survey found that 52 percent of Canadian respondents expect to spend more on gas than oil, more than 20 percent expect to trim their budgets.

Offsetting those trends, rig counts remain ahead of last year’s pace, with 60 percent of the activity targeting gas, and well completions are 20 percent higher than 2005.

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It appears there is limited upside potential to Canadian spending plans this year (unless there is a strengthening of natural gas prices), Cigré Group said.

"The price likely to yield 10 percent budget increases, on average, is now C$10.07 (per thousand cubic feet), up slightly from C$9.98 in December and above the current 12-month futures strip of C8.28."

The search found that 52 percent of Canadian respondents expect to spend more on gas than oil, with 27 percent expecting to trim their budgets.

The Alberta Energy and Utilities Board issued 1,084 coal-fired methane permits over the first six months, down just 12 wells from the same period last year, but May’s count was 143 compared with 232 in May 2005, putting a dent in hopes of 4,000 coal-fired methane wells this year and 6,000 in 2007.

Companies already cutting E&P spending

The clouds over the Canadian gas sector have darkened further, driving down commodity prices, said the National Energy Board.

Aside from whatever jitters the prospects for the rest of this year are causing in the industry, the Alberta government is likely to be on edge, having based its 2006-07 budget on average gas prices of $6.78 per million British thermal units.

Calgary-based FirstEnergy Capital is not surprised by see SUMP page 12

Ingredients in place for price slump

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Calgary-based FirstEnergy Capital is not surprised by see SUMP page 12
Can pipeline regulations be simplified?

Regulatory Commission of Alaska convenes special hearing to gather views from interested parties and determine way forward

By ALAN BAILEY
Petroleum News

Government regulation of oil and gas pipeline tariffs and operating rules is intended to create a level playing field for all users of a pipeline transportation infrastructure and to ensure fair tariff levels.

But is pipeline regulation in Alaska excessive? Some pipeline operators have complained about the excessive cost and time of the regulatory process, saying that the regulatory burden inhibits oil and gas development.

And should a small pipeline that only carries products for the pipeline owner even be regulated? Or what about a pipeline where would-be shippers have all reached an acceptable commercial agreement for the pipeline use?

In December 2005 the Regulatory Commission of Alaska opened docket R-05-011 to investigate the possibility of reducing the regulatory burden, perhaps by establishing two or more classes of pipeline with different levels of regulation.

The commission sought comments on possible regulation changes. And an RCA public hearing on June 13 provided an opportunity for interested parties to review and discuss the various comments that the commission has received. At the hearing, counsels representing BP Pipelines Transportation (Alaska) Inc., Union Oil Co. of California (a Chevron subsidiary), Marathon Oil Co. and Tesoro Alaska Co. talked to the RCA commissioners.

Current issues

Counsels for Union Oil and Marathon expressed frustration with the time and cost involved in the regulatory process for the construction of the Kenai Kachemak gas line that the two companies own on the west side of the Kenai Peninsula. The KKPL regulatory process continued for three years, despite the fact that the pipeline has only carried gas for Union Oil and Marathon, said David Robinson, counsel for Marathon. The regulations require massive amounts of information, he said.

“At one point in the KKPL (regulatory) proceedings, as much as 25 percent of Union’s management time was focused with dealing with pipeline issues,” said Bradford Keithley, counsel for Union Oil.

Louis Veerman, counsel for BP, listed three BP pipelines on the North Slope solely used by affiliates of the pipeline operator and one of which simply transports gas to an oil field for enhanced oil recovery operations. Economic regulation of these pipelines serves no useful purpose and, unless a third party company requests access, regulation could be eliminated, Veerman said.

“That would reduce the cost of operating these pipelines, which serve an important function but which also need to run in a cost effective way,” he said.

Two factors

Keithley said that overregulation results from two main factors:

1. RCA generally interprets Alaska statutes to mean that any pipeline on state land outside a unit boundary is a regulated transportation line rather than a gathering line associated with oil or gas production (the statutes exclude gathering lines from regulation but do not provide a clear definition of a gathering line).

2. RCA applies the same comprehensive regulations to all regulated pipelines, regardless of the pipeline use.

And Keithley compared the situation in Alaska with that in Texas and Oklahoma, where he said that many pipelines are classified as gathering lines and are regulated at a relatively low level. In these states, regulators respond to comments on possible regulation changes. And in Texas and Oklahoma, he said, the regulatory process is significantly shorter than in Alaska.

see REGULATIONS page 12
NORTH SLOPE

Kaktovik’s Native village corporation, unlike village, will work with Shell

Kaktovik’s Native village corporation has distanced itself from a village government resolution denouncing Shell Oil for pursuing oil exploration in whaling grounds offshore northern Alaska.

The Kaktovik Inupiat Corp. said in a June 5 statement that “the best way to deal with Shell Oil Co. is to work out issues in a civil and cordial manner.”

In May, the village City Council passed a resolution calling Shell “a hostile and dangerous force” and authorizing the mayor to take legal or other actions necessary to “defend the community.”

Mayoral Lon Somalla said Shell had failed to address village concerns about how it would keep seismic testing scheduled for this summer from disturbing migratory bowhead whales and how the company would operate safely in unpredictable sea ice.

Last year Shell leased nearly a half million acres in federal waters of the Beaufort Sea, some near Kaktovik, an Inupiat village of nearly 300 people on the Beaufort coast.

Shell’s seismic tests this summer will call for airguns from a ship to send sound pulses through the sea floor. The pulses bounce back up to the ship for an image of rock formations potentially bearing oil and gas.

Shell needs permits from the U.S. Minerals Management Service, which regulates offshore oil operations, and the National Marine Fisheries Service, which manages sea mammals such as the bowhead whale.

The Kaktovik Inupiat Corp. owns land near the Arctic National Wildlife Refuge coastal plain and has supported opening that area to oil development. Its shareholders include Kaktovik residents and whaling captains.

However, the corporation “opposes all activity at our whaling grounds,” it said in the statement, and it has concerns about how well oil spills can be prevented or cleaned.

But it noted that Shell has negotiated with North Slope whalers over its Beaufort activity and has signed an agreement to shut down until Kaktovik, Nusuit and Barrow whalers meet their quotas.

“The reality is the federal government has already sold oil leases and activity will take place,” the corporation said. KIC is “willing to work with Shell Oil Co. so that we may have a say on what goes on during whaling and other subsistence that we engage in.”

—BILL WHITE

Archangel Daily News

continued from page 10

SLUMP

this trend, forecasting winter prices will remain strong regardless of how full storage reservoirs become.

In a new analysis, the firm said factors underlying winter prices include the continued high import oil prices, concerns about the prospect of hurricanes in the Gulf of Mexico (which drove gas futures to US$7.33 on July 31 last December) the chances of a “normal” winter and the diversion of LNG cargoes from the U.S. if high prices take hold in overseas gas markets.

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—BILL WHITE

Archangel Daily News

continued from page 11

REGULATIONS

plaints from third party shippers, using rate complaints or rules of thumb to determine equitable rate levels, he said.

Robinson said that in Louisiana the public services commission only regulates public utilities pipelines for 30 days after the office of conservation (the state agency that regulates oil and gas production) regulates other lines. Just two people in the office of conservation regulate 100 intrastate pipelines, he said.

Tesoro’s views

Tesoro takes a different view of pipeline regulation from some of the other companies represented at the RCA hearing.

“Our position is that the regulatory regime that’s been in place has worked well for 40 years and it’s created certain— for producers, explorers and owners, everybody involved,” David Wensel, the company’s counsel told commissioners.

As well as using products delivered to its Nikiski refinery through various pipelines, Tesoro operates a regulated pipeline that carries petroleum products from Nikiski to Anchorage.

Businesses need access to pipelines with fixed tariffs and it is necessary to balance the cost of the regulatory burden against the benefits that regulation brings, Wensel said.

Wensel emphasized the importance of being able to assess future pipeline tariffs and regulatory requirements when planning new projects. And achieving a level of certainty in these assessments depends on “litigation quality numbers,” rather than the summary or approximate data that might result from simplified regulation, he said.

Wensel said that much of the time and cost associated with pipeline regulation in Alaska results from litigation. RCAs could exert some control over the amount of litigation generated, he said.

However, Keithley said that much of the regulatory burden derives from the numerous meetings and negotiations involved in developing acceptable tariffs. Wensel also said that Tesoro finds it difficult to comment on simplified regulations in the absence of specific proposals for regulation changes.

“Today we’re here in a vacuum,” Wensel said. “We don’t have a specific proposal to kick around.”

Wensel also questioned ideas of trying to apply simplified regulations to small pipelines — it is difficult to define what is meant by a small pipeline and a small pipeline could prove just as important as a large pipeline to someone wanting to develop a new oil or gas pool, he said.

Simplified regulations

However, Keithley suggested that simplified regulations could apply to a user-owned pipeline where there is no request for third-party transportation or to a pipeline where RCA has determined that the tariff is minor to the point of not significantly impacting exploration and production economics. He floated the figure of 25 cents per thousand cubic feet as the “de minimis” tariff that a carrier might apply to a gas line.

Keithley also recommended obtaining ideas for less burdensome regulation from other states.

Robinson thought that in the case of a user-owned pipeline, a regulation requiring just one or two sentence tariff statement might suffice.

“In many of these cases there’s just never a need for third party (pipeline) use,” he said.

And Keithley emphasized the value of only requiring full pipeline economic regulation at the time when a third party shipper requires service. In this situation the commission could apply an industry-standard rate as an interim tariff, while the pipeline operator applies for the regulated tariff, he said.

After some discussion the company counsels at the meeting volunteered to develop some proposed new regulations for consideration by RCA. And the RCA commissioners agreed with this strategy.

However, Commissioner Dave Harbour pointed out that, as a rule making process, the proceedings are completely open to all members of the public.

“When any of the public can submit to us a suggestion at any time about what rule should be,” Harbour said.

Harbour also cautioned about the dangers of assuming that a pipeline will never be needed by a third party shippers.

“You have to assume that at some time a third party will materialize . . . then you need the numbers that will give you a basis for going forward,” he said, referring to data such as the cost base for tariff determination.

Harbour also said that some specific details, such as de minimus tariffs, require clear definition. He added that there is a probable need to ensure that state regulations mesh seamlessly with the equivalent federal pipeline regulations.

Commissioner Mark Johnson said that any regulation should not proceed with the caveat that the carriers can sign onto any proposed regulation, or for me it becomes meaningless, he said.

Plan of action

At the end of the hearing Commissioner Chair Kate Giard proposed a plan in which Union Oil, Marathon and BP would arrange a presentation to the commission on pipeline regulations in states other than Alaska and on federal pipeline regulations. The interested parties would then convene workshops, facilitated by RCA, to develop proposed regulations, for submission to RCA by the end of December.

RCA would then have a further year to complete the public processes, a regulation range. In any case, the carriers can sign onto any proposed regulation, or for me it becomes meaningless, he said.

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JUNE 18, 2006

www.pnnews.org
Agency: BP can operate pipelines with alternate safety tests

By DAN JOLING
Associated Press Writer

Federal regulators have denied a request by BP Exploration (Alaska) Inc. to postpone testing of North Slope low-pressure transit pipelines with internal devices that clean lines or detect physical problems.

The company, however, can continue operating the lines as it uses alternate testing methods to detect problems.

The Pipeline and Hazardous Materials Safety Administration, part of the U.S. Department of Transportation, on March 15 ordered BP to test within three months three low-pressure oil pipelines with a “smart pig,” which runs inside the pipe and detects anomalies and weak spots.

The order called for BP to run scraper pigs through pipes to push out sediment and solids. The company also was to correct problems and report its progress.

The agency ordered the testing two weeks after BP discovered the largest oil spill in North Slope history, a leak of an estimated 201,000 gallons onto the tundra from a 34-inch pipeline in Prudhoe Bay’s western operating area.

“The agency’s corrective action order called for maintenance pigging by June 12 and inspection with the smart pig by June 14.

These deadlines will not be met but BP will be allowed to continue operating the transit lines to move oil to the trans-Alaska pipeline.

BP pleased with decision

“We’re pleased that the Department of Transportation has authorized the continued operation of the BP transit lines and have made a preliminary determination that the testing alternatives we have proposed will meet the agency’s intent,” said company spokesman Daren Beaudo.

BP said factors outside its control made the deadlines impossible to meet and it petitioned for an extension.

One factor, Beaudo said, was a grand jury subpoena requiring BP to remove a pipe and it petitioned for an extension.

Also, BP has yet to work out a plan with Alyeska Pipeline Service Co., operator of the trans-Alaska pipeline, for the capture and disposal of the cubic yards of solids generated by pigging the line from the Prudhoe Bay eastern operating area, Beaudo said.

BP will continue to work to reach full compliance with the corrective order, Beaudo said. It has met regularly with agency officials in Anchorage, Denver and Washington, D.C., he said, keeping them apprised of alternative monitoring.

Inhibitor now being directly injected

One reason for the leak, Beaudo said, is that corrosion inhibitor may not have reached the affected pipeline. Corrosion inhibitor is now being injected directly, he said.

The company has begun 30 alternate testing methods, including radiography, ultrasonic testing and collection of data from 2,200 locations along the 22 miles of pipeline under review. The company is conducting monthly measurements of corrosion inhibitors and has installed devices that allow monitoring of lines beneath gravel roads and gravel caribou crossings.

“We have a really good idea of the condition of the lines,” Beaudo said.

The agency said the testing alternatives and BP’s enhanced monitoring appear to meet the agency’s intent. However, the requirement for the internal testing will remain and it may add requirements following a review of the company’s data.

“Our objective is to ensure their pipelines are completely safe,” said Tom Barrett, agency administrator.

In a letter to BP, associate administrator Stacey Gerard said the pipeline safety office was not ready to complete its evaluation and that it “reserves the prerogative to seek civil penalties for violations of these requirements.”

Lisburne pigging began June 10

Pigging of a line from the Lisburne oil field began June 10.

The earliest two sections of the eastern area transit pipe could be inspected and cleaned is mid-July and mid-October, Beaudo said.

The earliest the western area could be started is the second quarter of 2007, Beaudo said. Another complicating factor is that the pig launcher is upstream of the 34-inch line that’s now shut in.

“We’re going to have to put in a new pig launcher,” he said.

BP is part owner of the Prudhoe Bay oil field, the nation’s largest, but operates it for all owners.

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INTERNATIONAL

Browne: BP to spend $50 billion on exploration, production next five years

According to a June 14 report in Forbes, BP Chief Executive Lord Browne told reporters that BP plans to invest US$50 billion on oil and gas exploration and production over the next five years.

The money will be spent to bring online natural gas from Alaska, Indonesia, Egypt, the Caspian and East Siberia, while more oil will be extracted from Angola, Russia and the Gulf of Mexico, Browne said at a news conference marking the launch of BP’s Statistical Review of World Energy. The $50 billion represents a $3 billion increase over what BP has spent on E&P worldwide in the last five years, the magazine reported.

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● NORTHERN SLOPE

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PETROLEUM NEWS
Disadvantaged compared to what?
The state’s fiscal interest finding compared transportation costs of more than $2 per million British thermal units for the Alaska project to $1.20 per million Btu for liquefied natural gas. Leitzinger said Econ One’s estimated tariff of $2.17 per million Btu is lower than the $2.25 the state used.

More significantly, the state’s transportation cost for LNG includes only tanker transportation, he said, and does not include per-million-Btu costs of 75 cents for liquefaction, 40 cents for regasification and 10 cents for transportation from the regasification facility to market.

This kicks the total LNG transportation cost up to more like $2.50 per million Btu, he said, somewhat higher than either $2.17 or $2.25, which are leveraged nominal dollar figures for the life of the project. Since the ANS gas pipeline project wouldn’t start moving gas for some 10 years and then continues for several decades, a comparison with today’s LNG transportation rates in inappropriate, he said. In today’s dollars the pipeline tariff is about $1.20.

Leitzinger said he sees no comparison with LNG transportation costs that places the Alaska project at a disadvantage.

The net present value per barrel of oil equivalent reflects net value for energy including the cost of transportation, he said, and achieves a target level at prices above $4 in Alberta. At $5.50, the number the state used, there is plenty of revenues left over after transportation to support costs, Leitzinger said.

Transportation, investment implications
What are the investment implications of the transportation costs? Eighty percent of the money for the project will come from lenders as limited recourse loans backed by federal government loan guarantees that will reduce the loan costs and will be secured by shipping commitments, Leitzinger said. Tariff rates are set on debt to allow recovery of the loan costs, he said, and if the regulators do their job the rate allowed on equity will be sufficient to attract capital to the project. Leitzinger said the willingness of independent companies to build the project subject to regulated returns indicates those rates are not too low.

He said the fiscal interest finding discussion indicates the state believes the producers are not willing to supply gas to a project they don’t build and that it would take years to wrestle the gas away from them.

Because the sponsors are exploration and production companies they want an E&P return for the project, he said, not a pipeline return, and part of what is driving the state’s analysis is how to get more than a regulated return for the project.

The sponsors have combined equity capital of $676 billion, 95.9 percent of their capital structure, he said, with only 4.1 percent debt. Leitzinger said on the debt to build the pipeline would only increase the companies’ collective debt by 2 percent. Leitzinger said he didn’t think the difference between 4 percent and 6 percent debt would have any significant impact on the cost of capital to the companies on their ability to raise capital.

At a $6 per million Btu expected price and a transportation cost of around $2, Leitzinger said there is little shipping risk over the life of the project, noting that a $2 gas price in Alberta seemed to him a remote possibility.

IRR poor investment metric
Leitzinger said the state’s fiscal finding calling internal rate of return the project’s “Achilles’ Heel,” but said IRR pipes the relationship between present cash out and later cash in and is a poor investment metric especially with different risk profiles for the oil and gas projects, different time frames and different costs.

The fiscal finding treats the $2.1 billion project cost as a cash outflow at the beginning, he said: but it’s not a cash outflow from the sponsors and not a correct use of IRR.

In the comparison with projects around the world from PFC in the fiscal finding there are some projects which include full capital costs, he said, and unless you put all the right costs in other projects you won’t get valid comparisons.

The Alaska project is also compared to both oil and gas projects, and transportation economics are fundamentally different between oil and gas projects, he said. With different expected returns, different uses for the oil or gas, different returns and different reasons to pursue the projects.

Leitzinger said he doesn’t believe it, but even it if were true that it makes sense to put all transportation costs into IRR and compare projects, you would have to recognize that the regulated gas pipeline business has a lower risk profile than energy marketing and energy development. The Alaska project is heavily weighted with pipeline costs so an across-the-board comparison of oil and gas projects is not fair, he said. Comparing apples to oranges, he said.

Leitzinger said that as an economic matter it fails to compare the Alaska North Slope gas project is challenged today based on market prices and costs. It is economically viable on its own terms today’s taking he said, and with the needs of companies to replace reserves it holds out the prospect for adding one of the largest known reserves bases and has one of the highest net present values.

Leitzinger also said he sees no reason to say the Alaska project stands behind other projects because other projects on the comparison list are sanctioned and moving ahead.

As for risk, the net present value of 10 percent is more than enough to offset and compensate for risk, he said.

How risky is the Alaska project?
Tony Finizza, an Econ One consultant, compared the Alaska project with other investment projects and said the project is not disadvantaged under present fiscal terms.

He also assessed the cost overrun risk and risk of not finding reserves. He said the consultant Pedro van Meurs in May testimony Van Meurs had concluded that because of the combination of cost overrun risk and price risk there is a 20 percent to 30 percent chance that the project will not be built, even with a fiscal contract in which the state gave substantial financial incentives to the builders of the line.

Finizza said Econ One believes the probability of having an uneconomical project is “far smaller” than 20-30 percent. If you examine two low-chance events the chance of both happening at the same time is significantly smaller than either happening by itself, he said.

The Econ One analysis assumed the risks are correlated because high capital costs are more likely when prices are high because there is increased industry activity and competition for materials.

Finizza said the risk of an uneconomic project under various price and cost overrun distributions ranges from less than 1 percent under a U.S. Department of Energy, Energy Information Administration scenario to about 5 percent under the fiscal interest finding scenario.

COOK INLET BASIN
Alaska Crude prepares to re-enter Moose Point No. 1
Alaska Crude Corp. is about to re-enter the Moose Point No. 1 well, in privately owned land near the northern end of the North Kenai Road on Alaska’s Kenai Peninsula.

“The drilling will probably start next month,” Bruce Webb, vice president, regulatory affairs, for Alaska Crude Corp, told Petroleum News. “Right now we’re digging a trench around the pad to keep the pad drained.”

The company has two drilling rigs, either one of which can do the drilling.

“Everything is out there except the choke manifolds and the blowout preventer,” Webb said, adding that the company expects to obtain those two remaining items in the next couple of weeks. All of the required permits are in place, Webb said.

Amorox Inc drilled the Moose Point No. 1 well in 1978 to a depth of 10,058 feet. The well had a gas show but Amorox was exploring for oil, Webb said.

Alaska Crude hopes to find commercial quantities of natural gas and has been negotiating with Amorox as a possible purchaser for the gas, he said.

The well is fairly near the ConocoPhillips gas line from the North Cook Inlet field to Nikiski and penetrates a known structure that Webb described as a faulted nose off the Snow River field.

Alaska Crude is a small independent oil company headed by Jim White, a long-time oil and gas investor in Alaska leases.

—ALAN BAILEY
ConocoPhillips pulls bid for LNG port
Governor opposes project offshore Alabama because of open loop vaporization; company uncertain it would look at closed loop

Governor Bob Riley said June 9 that the Houston-based company was withdrawing its application in a letter to the federal Maritime Administration.

Riley had set a deadline of June 11 to veto or permit the application for an LNG terminal south of Dauphin Island using what is known as an “open loop” vaporization system. Riley had indicated he opposed that kind of system and would veto the application in an announcement at Mobile on June 9.

“We’ve been having conversations with them for the last few weeks,” Riley said. “I was prepared to veto that. They made the decision they wanted to withdraw the application.” Riley has said he would not allow “any activity that I believe may adversely impact our marine resources if I have the power to stop it.”

Environmental and conservation groups urged Riley to veto the project, as Louisiana Gov. Kathleen Blanco did in May on a McMoRan Exploration Co. application. Riley had publicly supported Blanco’s veto.

Critics concerned about harm to marine life
Critics of the “open loop” vaporization system say it could harm marine life, particularly fish eggs and larvae, as it uses massive amounts of warm waters to reheat the LNG and turn it back into a gas.

The proposed Compass Port terminal off Dauphin Island would be capable of importing the equivalent of 1 billion cubic feet of liquefied natural gas and vaporizing it each day. Federal officials say the system would cool 136 million to 177 million gallons per day of seawater.

Environmentalists have fewer objections to a closed loop system for LNG terminals, in which some of the LNG is used as fuel to reheat the rest.

While ConocoPhillips had no immediate comment, Riley said he believes the company is “going to look at some different technologies now.”

“I think they are going to go back and look at a closed loop system that is a lot more environmentally sensitive. I think it’s going to give them an opportunity to reassess their whole LNG structure,” the governor said. A ConocoPhillips spokesman said the process of gaining regulatory approval for the project is lengthy and expensive and the company would have to review whether it wants to start over with a closed loop system for the Compass Port terminal, which was projected to create 600 jobs.

“I’m not saying what we’re going to do. We have to think about it.” ConocoPhillips spokesman Steve Lawless said June 9.

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### Companies involved in Alaska and northern Canada’s oil and gas industry

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*All of the companies listed above advertise on a regular basis with Petroleum News.*

### Northern Air Cargo

Northern Air Cargo celebrates 50 years of providing services to rural Alaska. With the recent change in ownership and recapitulation of the airline, NAC is positioned to continue to grow and improve the overall quality of services it provides customers. NAC has just purchased three 737-200 aircraft that will be put into service in the first quarter of 2007. Before joining NAC, David Karp served four years as executive director of the Alaska Tourism Marketing Council and most recently seven years as chief operating officer at Hawaiian Vacations. He joined the NAC team this February. Dave and wife Debbie have four children. Aside from family activities, Dave supports numerous Anchorage civic organizations.

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PARTNERS

lenging environment.

Currently, the Chevron-BP JV is mak-
ing preparations to drill two wells this
winter, while Devon has obtained a license amendment to stall its next well
until the 2007-08 winter.

The joint venture is open to farning
out stakes in four exploration licenses
covering 1 million acres of the Delta-
Beaufort including stake in the winter
wells, Sharon Murphy, Chevron vice
president of policy, government and pub-
lic affairs, told Petroleum News.

For now, Chevron and BP have decid-
ed that the four exploration licenses were
unlikely to match the scale or size needed
to compete with other opportunities avail-
able to the two companies, she said.

But Murphy said the licenses could
open the door for a new player to “estab-
lish a presence in a proven hydrocarbon
region at a reasonable cost” or allow
established explorers to expand their
holdings.

She said the decision to look for a part-
er is not a sign of diminishing interest by
Chevron, which holds firm to its belief
that the Delta-Beaufort will eventually
emerge as a major producing area.

Devon remains open to third parties

The same message came from Devon
Canada Vice President Michel Scott, who
said the company has been unable to
come to terms in the past with potential
third parties, but the door remains open.

Now that Devon has managed to
extend by one year its commitment to
drill a second well in the Beaufort “there
is more time for something that makes
sense” to develop, he told Petroleum
News.

In the meantime, Devon, after failing to
make the hoped-for multi-trillion-
cubic-foot discovery this year with its
Paktoa C-60 well in the Beaufort has, for
a nominal refundable fee, persuaded the
Department of Indian and Northern
Affairs to move the commitment to drill a
second well to a winter to next.

In any event, Devon had not locked up
the steel drilling caisson (SDC) deployed by EnCana in 2003 at the Alaska Beaufort
McCovey prospect and used for Paktoa,
leaving it with no choice but to postpone
its upcoming winter plans, Scott said.

That is emphatically not a sign that
Devon has any thoughts of pulling back
its upcoming winter plans, Scott said.

Although the C$60 million Paktoa
drilling was initially thought to be a
intermediate well, it was not planned to
reach the structure.

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secon
right on the heels of a mission to
Calgary to sell the Canadian
petroleum industry on Colombia's
efforts to separate itself from its
nationalist-bent neighbors, the
South American country was
clobbered June 13 by panic selling
on its stock market.

Major Canadian companies with
operations in Colombia are Nexen,
Enbridge and Talisman Energy, while
Petroleum Bank and Resources is
holding an initial public offering of its
Colombian subsidiary which produces
3,000 bpd and has close to 2.5 million
acres under lease.

Petroleum Bank President John Wright told
reporters that Colombia is a "fantastic"
place to do business.

GARY PARK

Beverly Hills firm
protests PN's coverage
of Arctic claim

THE MAY 21 OIL PATCH INSIDER
carried a brief by Allen Baker titled
"Unoilgas claims Arctic Ocean common
area," a reprint of which you will find on
page 19 of this issue.

www.unoilgas.com is the home page for
a Beverly Hills, Calif. company
called United Oil and Gas Consortium
Management Corp., which sent
Petroleum News a press release in mid-
May saying it "has claimed Exclusive
Rights to the 3,000 square mile seabed
within the international waters of the
Arctic Ocean Common area for oil and
gas resource exploration."

We chose to report this news as part
of Oil Patch Insider, which allows our
writers to insert some opinion.

In this case, writer Allen Baker insert-
ed both skepticism and humor.

United Oil and Gas Consortium's
Peter Sterling (unoilgas@yahoo.com)
disagreed with what we wrote.

Following are the points he made in
his letter, and responses from the two
Alaska geologists Baker received infor-
mation from regarding unoilgas' Arctic
claim, as well as a comment from Baker.

The geologists are Bernard Coakley,
co-chair of the Department of Geology
and Geophysics at the University of
Alaska Fairbanks, and Alan Bailey, staff
writer for Petroleum News.

PETER STERLING: Someone had to
do it. The Law of the Sea allows for
mining operations in international
waters.

BERNARD COAKLEY: No one has
to do it. Allowing for mining operations
is considerably different than claiming
of much of the central Arctic for the pur-
pose.

PETER STERLING: The two "geolo-
gists" your journalist Allen Baker con-
sulted obviously don't know what's hap-
pening in the Arctic.

BERNARD COAKLEY: These guys
(unoilgas) know just enough to confuse
the issue.

PETROLEUM NEWS: Coakley has
spent much of the past 12 years
researching the geology of the various
ridges, plateaus and sub-basins that lie
beneath the Arctic Ocean. He led the
geophysics program of SCICEX, a series
of unclassified cruises to the Arctic on
U.S. submarines, and late last summer
was co-chief in a research cruise across
the Arctic Ocean by the U.S. Coast
Guard icebreaker Healy.

That cruise, which crossed all of the
major ocean basins and ridges, collected
about 2,200 kilometers of multi-channel
reflection data that reveal the stratigraph-
ic record of the ocean. The seismic sur-
veys used two 250-cubic-inch airguns, a
200- to 300-meter streamer and nearly
100 sonobuoy deployments.

...staff writer Alan Bailey has a doc-
torate in geology. One of his main feats
for Petroleum News is the Arctic.

PETER STERLING: Drilling can and
has been done in the shifting Arctic ice.
The summer 2004 Arctic Ocean Lomonosov
drilling project successfully drilled to about
400 meters below the sea floor on the Lomonosov Ridge.

PETER STERLING: Little chance of
finding oil in the Arctic? Again your
"geologist" sources must have been hid-
ing under a rock for the last 40 years.

Within the U.S. controlled Arctic Ocean
EEZ, the Minerals Management Service
(MMS) has recently identified a total of
39 plays, including 24 Brookian plays,
in the Beaufort and Chukchi sea plan-
ning areas. What makes this region par-
ticularly intriguing is the size of some of
the structures — more than 12 of the
identified structures exceed 150,000
acres in extent, thus exceeding the size
of either the Prudhoe Bay or Kupark River
Fields. There are 24 identified prospects
more than 100,000 acres in size and
95 more than 40,000 acres, the
approximate size of the Alpine field.

The Arctic Ocean Burger field was
then drilled in 1989-1990. Burger could represent the largest offshore discovery on the Alaska OCS with perhaps 7 Tcf gas and 724 Mmb condensate. “Plans to shoot seismic offshore Alaska’s Arctic are already picking up speed,” Shell, ConocoPhillips and Houston-based GX Technology Corp. all plan to shoot seismic this summer in the Chukchi Sea, ahead of the MMS Chukchi lease sale planned for 2007.”

ALLEN BAKER: Looks like he’s done a little reading on Alaska, but I’m skeptical when someone uses acreage as some measure for the size of an oil accumulation. One has nothing to do with the other.

BERNARD COAKLEY: His “claim” covers areas that have never been explored and cannot be while there is substantial ice. All of the areas he cites are on land and the continental shelves — well within areas contained in the present EEZs of Russia and the United States.

ALAN BAILEY: Peter Sterling is correct about areas such as Beaufortian Sea and the Chukchi Sea. But these are NOT international waters — they are part of the economic exclusion zone of the United States. I think that almost all of the areas of continental shelf where oil and gas potential is high fall within some country’s economic exclusion zone. There may be some areas of dispute, but adjoining countries will certainly claim these if they turn out to be extensions of the continental shelf. Canada, for example, has ambitions to claim at least some of the Lomonosov Ridge.

BERNARD COAKLEY: So does Denmark.

PETER STERLING: Meanwhile on the Russian side of the Arctic Ocean. The Giant Shitokman gas and oil field is about to get some company. The Arctic has been claimed. How else to interpret a press release we got this month from the United Oil and Gas Consortium Management Corp.? After all, it’s titled: “Father Christmas is about to open a new company.”

No, no, look at your calendar. It’s not the first of April. But right here (for those who believe in Santa) is the news that United Oil and Gas “has claimed Exclusive Rights to the 3,000 square mile seabed within the international waters of the Arctic Ocean Common area for oil and gas resource exploration.”

Never mind little details like the International Law of the Sea. Our fearless United Oil and Gas (Unoilgas for short) has “duly claimed priority over the area (by) International proclamation on May 9th 2006.” Those International proclamations apparently work kinda like your basic magic wand. Never mind other little details like the fact that two geologists we ran this past say there’s little chance of finding commercial oil even if you could drill in the shifting ice.

“There is one shelf area, the ‘keyhole’ north of Siberia, that could be prospective, that would be covered under their ‘claim,’ but this is a remote, difficult area,” one geologist told us. “Some of the deep basin could be prospective, but it is a very speculative possibility. At best, it could be an outstanding legacy for their great-grandchildren.” But hey, if it works out, those grandchildren will undoubtedly believe in Santa Claus.

In case you think we’re pulling your leg, you can find more about this exciting venture at www.unoilgas.com. They even want industry partners for their Study Group. Tell them the Easter Bunny sent you.

Editor’s note: Email addresses for the individuals quoted above are as follows: Bernard Coakley (Bernard.Coakley@gi.alaska.edu), Peter Sterling (anoolgas@yahoo.com), Allen Baker (abaker@mind.net), Alan Bailey (abai ley@PetroleumNews.com).
The Alaska Gas Pipeline
DELIBERATING JOBS, REVENUE AND BUSINESS OPPORTUNITIES TO ALASKA.

It's finally time for Alaskans to have the chance to say yes to the gas pipeline.

The agreement with the producers provides thousands of jobs for Alaskans and hundreds of opportunities for Alaska businesses.

It will generate billions of dollars in new state revenues — and billions more for the permanent fund.

It ensures Alaskans have access to North Slope gas and that the pipeline be expandable so future commercial discoveries can make it to market.

Thousands of new jobs, opportunities for Alaska businesses and billions in new state revenue.

While there's still work to be done, this is what we've been waiting for.

Alaska gas - It's time!

To find out how to get trained for a pipeline job, stop by any Alaska Job Center or go to www.alaskagasnow.com

Just the Facts

ROUTE
The Alaska Gas Pipeline starts at Prudhoe Bay and roughly parallels the Trans-Alaska oil pipeline and then the Alaska Highway.

COST
$20 billion plus (2001 dollars), which ranks it as one of the largest private projects in North America.

THE PIPELINE
Large diameter, high-pressure, mostly buried chilled pipeline.

Thousands of jobs will be needed to build the Alaska Gas Pipeline.

The pipeline will help to stabilize Alaska's economy and create economic opportunities for all communities.

Gas for Alaska

This agreement provides the opportunity to access the pipeline at the Prudhoe Bay Field for the state of Alaska to meet the gas needs of interior, rural and south-central Alaska residents.

Speak up if you want a gas pipeline.

Tell the governor and your legislators that Alaska needs a gas pipeline now. Attend a community forum, comment on-line at www.alaskagasnow.com or call 1-888-512-5427 and leave a recorded message.