Petroleum news

page 3 Senate Finance tax bill would hold state revenues constant at $100 oil

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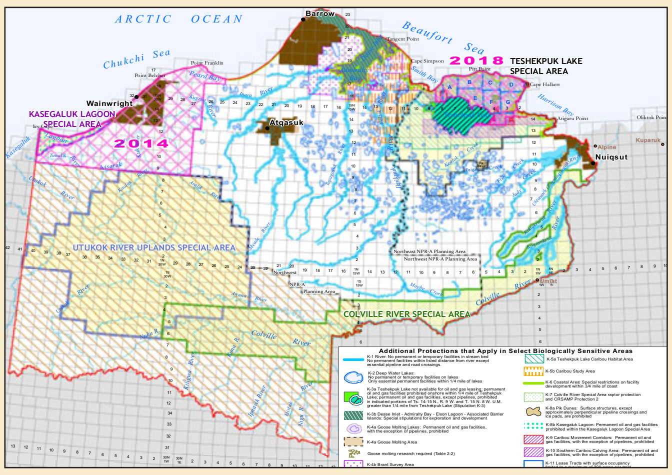
NPR-A draft plan out



Bureau of Land Management draft plan presents options with varying amounts of land withheld from development. See story page 10.

Mackenzie gas line partners suspend funding, close offices

In an April 5 first-quarter interim update ConocoPhillips said the company's board of directors approved the separation of Phillips 66 from ConocoPhillips — and that ConocoPhillips and its three partners in the C$16.2 billion Mackenzie Gas Project have suspended funding of the pipeline and gathering system due to a continued decline in natural gas prices and the lack of acceptable fiscal terms.

A spokesman for the lead partner in the group, Imperial, confirmed the information, telling Reuters that the Mackenzie Gas Project has closed offices in Norman Wells and Fort Simpson, Northwest Territories, and reduced the size of its office in Inuvik, N.W.T.

Here is what ConocoPhillips' interim update said about the

see **MAC LINE FUNDING** page 20

Apache plans 2 wells this year, onshore on either side of inlet

Apache Corp. plans to drill its first two wells in Alaska in the second half of the year.

As part of a regional, multiyear oil exploration campaign in Cook Inlet, the Houston-independent is permitting onshore wells on both the east and west side of the inlet.

Apache plans to start by drilling the Aspen well in July.

The well would be located about four miles west of Tyonek, amid a thicket of previously drilled wells. Those in the immediate vicinity include Aurora Gas' Aspen No. 1, Humble Oil's Tyonek Reserve No. 1 and Simasko's Simpco East Moquawkie No. 1.

see **APACHE WELLS** page 20

Preliminary injunction bans Greenpeace from Shell vessels

On March 28 Judge Sharon Gleason in the federal District Court in Alaska issued a preliminary injunction banning activist organization Greenpeace from occupying any of a list of 19 vessels that Shell plans to use for exploratory drilling in the Beaufort and Chukchi seas during this year's open water season. The list of vessels includes the drillship Noble Discover, the floating drilling platform the Kulluk, anchor handlers, icebreakers and oil spill response vessels, with the ban continuing until Oct. 31and applying while the vessels are in U.S. waters and ports.

Members of Greenpeace and "all others who are in active concert or participation with Greenpeace" are banned from breaking into or trespassing on the vessels; interfering with ves-

see **VESSEL INJUNCTION** page 17

EXPLORATION & PRODUCTION

'Bigger than us'

With proved 40M barrel discovery at Mustang, Brooks Range looks for capital

By KAY CASHMAN
Petroleum News

Brooks Range Petroleum Corp. has proved up a 40 million barrel discovery on Alaska's North Slope; that's 40 million barrels of recoverable oil, which can be expected to produce for 15 years, yielding 13,500 barrels of oil per day at its peak.

1 2 SERIES

The Mustang prospect, formerly known as North Tarn, in the new Southern Miluveach unit on the southwestern boundary of the Kuparuk River unit, held more recoverable oil than Brooks Range expected — in the Kuparuk sands, which had been the company's secondary target.

> *"We're looking for a partner that can come in and take a large portion of our working interest in return for funding."*
> **—Ken Thompson, AVCG lead managing member**

"The Kuparuk is good quality sands with excellent pressure and oil flow capability," Alaska Venture Capital Group LLC's lead managing member, Ken Thompson, told Petroleum News April 3.

Mustang, its recoverable reserves established with four penetrations, plus three other smaller developments and numerous exploration upside

see **BROOKS RANGE** page 19

GOVERNMENT

Point Thomson settled

State, oil companies agree to schedule for developing North Slope field

By WESLEY LOY
For Petroleum News

A seven-year fight for control of Alaska's rich but undeveloped Point Thomson field came to an end March 30 with the announcement of a legal settlement between the state and major oil companies.

The deal snuffs a high-stakes conflict that could have run years longer, and holds out the prospect of a modest level of production by early 2016 from the remote North Slope field.

Longer term, the deal offers hope that field operator ExxonMobil and its partners might invest billions of dollars to fully develop Point Thomson. And state officials said removal of the legal cloud over the field improves chances for an even greater prize — construction of a pipeline to market the Slope's vast but stranded natural gas reserves.

> *At the IPS stage, the settlement also calls for drilling another well on Point Thomson's west pad by the end of the 2016-17 winter season.*

Since ExxonMobil discovered the field in the 1970s, Point Thomson hasn't produced a single barrel of oil or molecule of gas, and the settlement makes no guarantee that it ever will.

But state officials, long frustrated over what they call the "warehousing" of Point Thomson resources,

see **THOMSON DEAL** page 17

GOVERNMENT

Canada to speed approvals

Government sets 2-year deadlines on major energy projects environmental reviews

By GARY PARK
For Petroleum News

The Canadian government of Prime Minister Stephen Harper has moved decisively on its dream to create a global energy superpower and open access to Asian markets by overhauling regulatory hearings and putting a crimp on environmental opposition.

Taking the unusual step of using its federal budget as the vehicle for change, the government imposed a cap of two years on regulatory reviews while stepping up its scrutiny of charities such as environmental organizations which are restricted to spending 10 percent of their budgets on political activities.

The immediate beneficiaries could be Enbridge's Northern Gateway proposal to export 525,000 barrels per day of oil sands crude from the British Columbia coast and Kinder Morgan's evolving plan to double capacity on its Trans Mountain pipeline to 600,000 bpd, all of the increased volumes aimed at Asia-Pacific markets.

> *The changes will affect all major natural resource projects, with the greatest impact on oil sands development and energy pipelines along with hard-rock mining.*

Ian Anderson, president of Kinder Morgan's Canadian unit, said the changes will "move the yardsticks significantly," while Enbridge spokesman Paul

see **PROJECT REVIEWS** page 18

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FINANCE & ECONOMY

Senate Finance tweaking production tax

Progressivity to be levied on gross production less royalty, not on net; goal to hold state's take constant at $100 barrel crude oil

By KRISTEN NELSON

Petroleum News

After weeks of work, Senate Finance put a committee substitute for Senate Bill 192, the bill to change Alaska's oil and gas production tax, on the table April 3. As Petroleum News went to press April 5, the committee was continuing to work on the bill, with industry testimony scheduled April 6.

Senate Finance co-Chair Bert Stedman, R-Sitka, said at a Senate Bipartisan Working Group press availability after the committee substitute came out that among the things still being worked was the issue of incentivizing incremental production from the legacy fields.


SEN. BERT STEDMAN

He said the bill could be out by April 7 or 8 — over the weekend and Senate President Gary Stevens said a Senate floor session would be based on when the bill moves out of the Finance Committee.

At the House Majority press availability April 2, House Speaker Mike Chenault, R-Nikiski, said he thought the Senate president had good intentions when he said the House would have the bill with a month left in the session, which ends April 15. Chenault said it's "very unlikely" the House will pass an oil tax bill before April 15 and said he wouldn't push to get a bill out just so the House could go home.

He said that once it gets the bill the House will take its time, making sure the bill would actually accomplish what it says it does. Chenault said "if that takes a week fine — if it takes six weeks that's OK, too."

Rep. Craig Johnson, R-Anchorage, House Rules chair, said that if the bill that comes from the Senate isn't fixable, the House would have the choice of just not acting on it.

He said the Senate has come up with some good ideas and if the bill spurs investment and puts oil in the pipeline he'd be willing to look at it, but he said it's been some five years since the Legislature passed the present production tax, ACES, Alaska's Clear and Equitable Share, and said he was concerned that if something substantial isn't passed there could be another five years of production decline before the Legislature takes another look.

"But I don't want to pass something bad; I'd rather not pass anything than pass something bad," Johnson said.

What's on the table?

The Senate Finance committee substitute for Senate Bill 192 is a structural change in the state's existing production tax. It removes progressivity from the net tax portion of the tax with the base rate, 25 percent, remaining the same and adds a progressive severance tax which would be levied on gross production (the amount of oil produced, less royalties, times the price). Progressivity would be levied solely on oil and the bill would use a progressivity structure similar to that under the current system.

In testimony April 4, Janak Mayer, a manager in the upstream and gas practice of PFC Energy and manager of PFC's consulting work for the Legislature, said the proposed progressive severance tax would start at $60 gross value at point of production, GVPP, and have progressivity of 0.27 percent beginning at the $60 GVPP threshold. At $120 GVPP a tax rate of 16.2 percent is reached and at that point progressivity would be reduced to 0.03 percent.

Progressivity would be capped at 20 percent.

Benefits of progressivity on gross

The benefits in assessing progressivity on the gross, rather than the net, are tied to what Mayer has described as difficulties in the existing fiscal structure.

The first involves natural gas, which under ACES is wrapped into the progressivity calculation along with crude oil on a Btu basis, despite the substantial price difference between crude oil and natural gas. If a major gas sale occurs, the lower value of natural gas would substantially dilute the value of oil under ACES as it stands.

The Legislature tried to address this issue in 2010 by decoupling oil and natural gas but Gov. Sean Parnell vetoed the bill, calling it a tax increase.

The Senate Resources version of SB 192 included a provision for decoupling under the existing ACES structure, but that would have required splitting costs between oil and gas production, which Mayer said would have created a high degree of administrative burden and also limited the state's ability to audit returns effectively.

By removing progressivity from the net tax assessed under ACES, progressivity can be applied only to crude oil, eliminating the need for separating costs.

A second problem with progressivity under ACES is that at high prices the high level of tax credits offered by the state can produce excessive levels of state support for some spending, with effective after-tax government support for exploration reaching above 100 percent at very high oil price levels. With progressivity on the gross, rather than the net, the effective after-tax government support for exploration would be flat at 65 percent, Mayer said.

The Senate Finance committee substitute for Senate Bill 192 is a structural change in the state's existing production tax.

The other difficulty with ACES is that options to incentivize new production are limited and complex.

Under a severance tax on the gross, he said, incentives can be provided to new production simply by eliminating or lowering the progressive severance tax.

Price of oil

When ACES was passed the price of oil was much lower and modeling for ACES was done with a base case of $60 a barrel, Mayer said in a March presentation to Senate Finance.

The impact of progressivity at prices seen recently of more than $100 a barrel was not analyzed in 2007 and there has been considerable discussion by industry that the share of revenue the state takes at higher prices makes the state's tax rate uncompetitive, a factor hurting investment.

While the bill is still in flux, a revenue comparison presented April 4 estimated for fiscal year 2013 showed that at $100 oil, ACES would bring in $3.228 billion, compared to $1.987 billion under House Bill 110, the governor's proposal which the House passed last year, and $3.177 billion under the Finance Committee substitute for SB 192.

'Work in progress'

Asked at the April 3 press availability whether the committee substitute being discussed in Senate Finance represented a caucus position, Stedman said that was a "work in progress" with 16 caucus members, and 16 different views. "We're working on that," he said. The 16-member majority caucus includes all 10 Democratic members of the Senate and six of the Senate's Republicans. All seven of the Finance Committee members are in the majority — two are Republicans and five are Democrats.

In committee discussions April 4, Finance co-Chair Lyman Hoffman, D-Bethel, expressed concern about how much money the proposal moved from the state to industry at high oil prices, and Sen. Johnny Ellis, D-Anchorage, the Senate Rules chair, asked for confirmation that the goal was to preserve the level of revenue to the state at $100 a barrel oil.

Stedman said level revenue at $100 a barrel was the goal, and said he would be working with PFC Energy later on adjustments to meet that goal.

Sen. Lesil McGuire, R-Anchorage, said she would like to see more done in the bill to incentivize new production. ●

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● EXPLORATION & PRODUCTION

ANS crude production down 3% in March

Drop in production led by 4.8% drop at Prudhoe Bay; Kuparuk River down 1.5%; Cook Inlet up 9% in February over January

By KRISTEN NELSON
Petroleum News

Alaska North Slope crude oil production was down 2.98 percent in March, averaging 591,066 barrels per day, a drop of 18,150 bpd from a February average of 620,607 bpd. The Cook Inlet basin, while averaging just 11,391 bpd in February, the latest month for which data is available, is up 9.1 percent over January.

The biggest drop in ANS production was at Prudhoe Bay, operated by BP Exploration (Alaska), which averaged 335,613 bpd in March, down 17,052 bpd or 4.8 percent, compared to 352,665 bpd in February. Prudhoe Bay production includes satellites at Aurora, Borealis, Midnight Sun, Orion and Polaris, as well as the separate Milne Point and Northstar fields. Milne Point and Northstar are both operated by BP.

ANS volumes are from the Alaska Department of Revenue's Tax Division, which reports oil production only by major production centers and provides daily production and monthly averages. Cook Inlet production, reported by the Alaska Oil and Gas Conservation Commission, or AOGCC, is available by pool and field, but only on a month delay basis.

Kuparuk also down

Production also declined at the ConocoPhillips Alaska-operated Kuparuk River field, averaging 132,792 bpd in March, down 1.53 percent from 134,851 bpd in February. Kuparuk includes satellites at Meltwater, Tabasco and Tarn, along with viscous West Sak production, and volumes from the separate Oooguruk and Nikaitchuq fields.

AOGCC data for Nikaitchuq, operated by Eni Petroleum US, shows the field averaged 8,032 bpd in February, up 9.8 percent from 7,315 bpd in January. AOGCC data for Oooguruk, operated by Pioneer Natural Resources Alaska, shows average production of 5,844 bpd in February, down 4.45 percent from an average of 6,116 bpd in January.

Other fields up slightly

Production from the BP-operated Lisburne field averaged 33,939 bpd in March, up 1.73 percent from a February average of 33,362 bpd. Lisburne includes Point McIntyre and Niakuk production.

The ConocoPhillips-operated Alpine field averaged 77,053 bpd in March, up 0.47 percent from a February average of 76,690 bpd. Alpine includes satellite production at Fiord, Nanuq and Qannik.

The BP-operated Endicott field averaged 11,669 bpd in March, up 0.18 percent from a February average of 11,648. Endicott production includes the Savant Alaska-operated Badami field. The most recent data for Badami, from AOGCC, shows 1,107 bpd in February, up 6.3 percent from 1,041 bpd in January.

Cook Inlet production up

AOGCC data for Cook Inlet show the basin's crude oil production averaged 11,391 bpd in February, up 9.1 percent from a January average of 10,441 bpd.

Cook Inlet producing fields include Beaver Creek, Granite Point, McArthur River, Middle Ground Shoal, Redoubt Shoal, Swanson River, Trading Bay and West McArthur River. Granite Point at 2,427 bpd, McArthur River at 4,541 bpd and Middle Ground Shoal at 2,412 bpd are the only Cook Inlet fields with production above 1,000 bpd.

ANS crude oil production peaked in 1988 at 2.1 million bpd; Cook Inlet crude oil production peaked in 1970 at more than 227,000 bpd. ●

Contact Kristen Nelson at knelson@petroleumnews.com

● FINANCE & ECONOMY

Birchcliff abandons sales process

By GARY PARK
For Petroleum News

The rollercoaster existence of natural gas-weighted Birchcliff Energy has seen the Canadian intermediate producer rise and fall on the same day as it announced the termination of a corporate sale process.

The company, which put itself up for sale in October and reported on March 14 that negotiations were "ongoing" while cautioning there was no assurance of "successful transaction," issued a release March 29 disclosing that it has not received an acceptable offer reflecting the value of the company.

Instead, Birchcliff effectively turned to business as usual, reporting it had entered into a bought deal equity financing and a private placement for combined aggregate gross proceeds of C$110 million.

It also set a capital budget for 2012 of C$292.2 million and estimated it will exit 2012 with production at 26,000 barrels of oil equivalent per day, up from current output of about 21,100 boe per day.

Company president and chief executive officer Jeff Tonken said in a prepared statement that Birchcliff's board of directors "turned down one verbal non-binding offer and one written non-binding offer" during the sales process.

He told the Calgary Herald the bidders were "international plays," not local gas companies, which he said "have no money left."

Price decline an issue

Based on the decline in natural gas prices and the decline in share values of its peers, Birchcliff decided "continued

see BIRCHCLIFF page 5

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● GOVERNMENT

Groups challenging Roads to Resources

Wilderness Society report argues that Alaska can't afford to build three major roads to remote oil, gas and mining operations

By ERIC LIDJI

For Petroleum News

The state does not have a financial plan in place to build three industrial Arctic road projects currently under consideration, according to a coalition of environmental groups.

"The projects do not have financial plans identifying how they will be paid for, nor has the state quantified expected resource-related revenue associated with them," Lois Epstein, engineer and Arctic program director from the Wilderness Society, wrote in "Easy to Start, Impossible to Finish II," a March 2012 report produced with help from both the Northern Alaska Environmental Center and the Alaska Conservation Alliance.

The accusation is not a revelation — the state believes the precise financial model for the projects should come later — but signals increased concern about the projects.

While the initial report in 2010 focused on a collection of proposed transportation projects from around the state, the second edition looks specifically at the proposed roads to Umiat, Nome and Ambler, all designed to improve access to Arctic resource plays.

The state shouldn't continue to spend millions studying those three projects until it first explains where it would get the money to build and operate them, according to the report, but should focus on smaller projects that improve the existing transportation system.

Combined, the three roads would cost between $1.7 billion to $2.4 billion to build and additional millions each year to maintain, according to the Alaska Department of Transportation and Public Facilities. By expanding road access to more of Alaska, the report speculates that these roads would also require "more troopers and wildlife enforcement personnel, more accident response and emergency evacuation and medical capabilities, and additional tourism services such as sanitation and litter facilities."

A major Parnell priority

While the desire to expand Alaska's road system into the wilderness is nothing new for policymakers, the "Roads to Resources" program dates back to the administration of Gov. Frank Murkowski and has become a major priority of Gov. Sean Parnell. The state has spent nearly $34 million since 2004 on the three Arctic projects, and the proposed fiscal year 2013 budget would dedicate another $24 million to studying those roads.

In his State of the State addresses, Parnell said the roads would increase oil production by improving access to remote resource plays and increase employment in rural Alaska.

Of the three projects, only one is specifically geared toward energy production. A road to Umiat, a staging area in the foothills of the Brooks Range, would improve the economics of two projects in the region: Anadarko Petroleum Corp.'s search for natural gas in the vast Gubik Complex and Linc Energy Inc.'s program at the Umiat oil field.

Those exploration programs aim to prove up discoveries that the U.S. Geological Survey and the U.S. Navy made in the late 1940s and early 1950s. They are generally believed to be large projects hampered primarily by their remoteness, but also by other factors, such as the geology around Umiat and the economics of bundling midsize fields at Gubik.

The roads to Nome and Ambler would improve the economics of mining projects in western Alaska, as well as connect rural population centers to the larger urban areas.

Is it corporate welfare?

The state acknowledges it does not have funding nailed down for building the roads, but believes it's worthwhile to fund preliminary permitting now in order to have something soon it can hand over to a public-private partnership for final design and construction.

The state argues that the economic development generated by these roads, particularly the increased royalties from additional oil and gas production out of the foothills, would justify their cost. With only a handful of exploration wells drilled in the area, though, it is too early to gauge the true resource potential of the region, according to Epstein.

That echoes the concerns some lawmakers expressed when Deputy Commissioner of Highways Pat Kemp testified before the Senate Finance Committee in February.

Sen. Johnny Ellis, D-Anchorage, said many of his constituents considered the Roads to Resources initiative to be "corporate welfare," and asked, "If this is benefitting a corporation and their shareholders, mostly, where is the private money to help fund these enormously expensive projects and the enormously expensive upkeep of these roads?"

Kemp said the state could actually save money by building the $200 million to $300 million road to Umiat, because under the current system of tax credits, the state pays around 40 percent of the cost of most snow and ice roads on the North Slope, millions of dollars each year. "In that view, we are in essence paying for the roads," Kemp said.

Without a more certainty of the economics of those plays, "it's possible that the state could be left with the bill for road construction as well as operations and maintenance if private sector resource development projects do not materialize," Epstein argued.

Federal funding a concern

If the projects don't materialize, Epstein believes Roads to Resources could actually harm federal funding for other transportation projects. While Alaska famously and infamously benefitted from extensive federal support in the past, Epstein pointed to a November 2009 letter where the U.S. Department of Transportation worried that "sufficient funds are not available from current recognizable sources to complete a number of large projects contemplated by the State's program" and urged "fiscal constraint."

The Parnell administration does not plan to use federal funds for the Roads to Resources projects, but did not respond to the concern about jeopardizing other federal funding.

Finally, Epstein noted the opposition to the projects from local communities worried about the impact of the road on their subsistence lifestyle. When accused of ignoring those concerns during the hearing, Kemp said: "There's quite a difference between the phrase 'they aren't listening' and the phrase 'they aren't doing what I want them to do,'" and said the permitting process was designed to collect and consider local concerns.

The U.S. Army Corps of Engineers received nearly 1,700 comments during the recently completed scoping process for the Umiat road, leading it to consider an alternative route that would utilize existing North Slope corridors and to delay permitting by a year. ●

Contact Eric Lidji at ericlidji@mac.com

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BIRCHCLIFF

negotiations would not result in a proposal that would reflect the long-term value" of its assets, he said.

The company received one vote of confidence from Seymour Schulich, a billionaire mining and resources executive who holds 26 percent of Birchcliff shares and who announced he will buy 5 million additional shares at C$7.65 each in a private placement for C$38 million.

He said the sale of the company "at the bottom of the commodity price cycle will not achieve an appropriate value for Birchcliff's shareholders."

The company also expects to raise gross C$71.9 million through a bought deal issue of 8 million shares, due to close April 19, plus an issue of 1.1 million flow-through shares at C$9.20 each. The proceeds from the flow-through shares must be spent on exploration and development and offer tax benefits to buyers. ●

Contact Gary Park through publisher@petroleumnews.com

● NATURAL GAS

TransCanada needs decision on changes

Has requested state to let it 'curtail' work on line to Alberta and focus on LNG project; another open season planned for this year

By BECKY BOHRER

Associated Press

The state could decide the week of April 2 whether to give TransCanada Corp. permission to shift its attention to a liquefied natural gas project, capable of overseas exports.

TransCanada has asked the commissioners of Natural Resources and Revenue to allow it to "curtail" its work on a line that would run from Alaska's North Slope into Alberta, Canada, to focus on a liquefied natural gas project, said Tony Palmer, the company's vice president for major projects development.

On March 30, the North Slope's major players announced that they were aligning with TransCanada to pursue an alternative liquefied natural gas project. Gov. Sean Parnell wanted the parties to get on the same page as a way to jumpstart seemingly stalled progress on a line.

Parnell said that if the market had truly shifted from the Lower 48, he wanted the companies to unite behind a project that would allow for liquefied natural gas exports to the Pacific Rim.

A lot of work transferable

Deputy Natural Resources Commissioner Joe Balash said a lot of the work that has been done on the Alberta option — notably on its northern stretch — would be transferable to a liquefied natural gas project.

TransCanada, which has an exclusive license with the state to pursue a line, had been focused mainly on the Alberta option but hadn't announced any agreements with producers for it. TransCanada in January filed environmental reports with federal regulators for the proposed line, and it faces an October deadline to apply to the Federal Energy Regulatory Commission for a certificate to build and operate the pipeline.

Under terms of the Alaska Gasline Inducement Act, under which TransCanada has been proceeding, the company can change its plans due to factors unforeseen at the time of licensing or due to regulatory actions, but that is subject to approval by the commissioners. Any changes cannot diminish the value of the project to the state or diminish the project's likelihood for success.

Balash said April 4 that a decision could come yet this week.

Among the issues that need to be addressed, he said, are the October filing deadline — TransCanada cannot deviate from it unless it's relieved of the obligation or the date is pushed, he said — as well as how TransCanada will satisfy its requirement to solicit the market every two years to gauge interest in a project.

Balash said there's a "tremendous amount" of field work and engineering that would be needed if TransCanada were to complete its application by fall.

Open season this year

TransCanada last solicited the market in 2010, holding what's called an open season for three months. TransCanada offered two options: a line through Alberta and a shorter line that would run from the North Slope to Valdez, Alaska, where gas would be liquefied at a facility that an unidentified entity would build and ship elsewhere.

Another solicitation is planned for this year, Palmer said. While details of the solicitation are being worked out, he said TransCanada's intent is to offer an Alberta option and a liquefied natural gas option. Later this year, TransCanada hopes to have an initial assessment of a project, like its destination and volume, Palmer said.

Balash said that if TransCanada were to shift gears, and work was to continue under the license, TransCanada would be limited to the $500 million in reimbursable costs from the state that it has been working with. ●

● FINANCE & ECONOMY

Encana seeking Asian partners

Gas-weighted US, Canadian properties have natural gas liquids, oil potential; Kitimat partners negotiating offtake agreements

By GARY PARK

For Petroleum News

Encana is speeding up its search for partners to developing languishing gas-weighted properties in the United States and Canada, giving high priority to the Kitimat LNG project in British Columbia.

Speaking at an LNG conference in Singapore in late March, Chief Executive Officer Randy Eresman also said his company is looking for a single partner to develop leases in the Collingwood shale, Tuscaloosa marine shale, Mississippi Lime and Eaglebine (wells targeting both the Eagle Ford and Woodbine shales) in the U.S.

RANDY ERESMAN

All of those properties have natural gas liquids and oil potential and are in the early stages of exploration and development.

"One of the things we've been trying to do is to get more liquids, particularly oil, in our portfolio," Eresman told reporters. "But because of the high initial cost, we think we might be best to reduce our risk to accelerate the point of commercialization by bringing in another party."

He said the partners in Kitimat — operator Apache with 40 percent and Encana and EOG Resources with 30 percent each — are negotiating offtake agreements and are prepared to offer up to 20 percent stakes to one or two anchor buyers.

A new ownership deal would see the partners jointly contribute equity to the export terminal, a pipeline and the development of the Horn River basin in northeastern British Columbia.

see ENCANA page 7

● EXPLORATION & PRODUCTION

EAB rejects Kulluk air permit appeals

Appeals Board denies review of air quality permit for Shell's Beaufort Sea floating drilling platform and associated fleet

By ALAN BAILEY
Petroleum News

The Environmental Appeals Board, or EAB, has rejected appeals against the Environmental Protection Agency's air quality permit for Shell's use of its Kulluk floating drilling platform for exploratory drilling in the Alaska Beaufort Sea, starting this summer. The board denied review of the permit, dismissing all of the issues raised in claims that the EPA had improperly issued the permit.

The decision by the EAB, the panel of judges with final authority over decisions made by the Environmental Protection Agency, came in response to three appeals against the Kulluk permit. One appeal came from a group of nine environmental organizations, one came from the Inupiat Community of the Arctic Slope and a third came from a private individual.

In an order issued March 30 the EAB said that the petitioners against the air permit had failed to show that the agency erred in issuing the permit.

The rejection of the appeal represents a significant step forward for Shell in its multiyear effort to start its planned Alaska Arctic offshore drilling program.

"Achieving a usable air permit for the Kulluk means Shell has, for the first time, all of the air permits needed to work in the Alaska offshore," said Shell spokesman Curtis Smith in a March 30 press release. "That the Environmental Appeals Board already rejected challenges to air permits for Shell's second drill ship, the Noble Discoverer, further validates the work Shell and EPA have done to assemble strong, environmentally responsible emissions programs."

On the web

See previous Petroleum News coverage:

"Groups question Shell permit legality," in Dec. 11, 2011, issue at www.petroleumnews.com/pnads/144380463.shtml

"Shell's permits upheld; EAB rejects appeals of OCS permits," in Jan. 22, 2012, issue at www.petroleumnews.com/pnads/252570395.shtml

"More OCS appeals," in Feb. 26, 2012, issue at www.petroleumnews.com/pnads/322366939.shtml

In January the EAB rejected appeals against air quality permits for Shell's use of the drillship Noble Discoverer in the Chukchi Sea or Beaufort Sea.

Other appeals

In January the EAB rejected appeals against air quality permits for Shell's use of the drillship Noble Discoverer in the Chukchi Sea or Beaufort Sea. Those permits were subsequently appealed to the U.S. Court of Appeals for the 9th Circuit — the 9th Circuit court has yet to rule in that appeal. The same court is also reviewing appeals against the approvals by the Bureau of Ocean Energy Management of Shell's Chukchi Sea and Beaufort Sea exploration plans.

According to the EAB order denying review of the Kulluk air permit, the petitioners against the permit raised seven issues, including questions over the way in which EPA had placed limits on the total emissions from the Kulluk and its support fleet; the exemption of a 500-meter zone around the Kulluk from ambient air standards; and the use of overlapping public comment periods for two different permits, including the Kulluk permit.

The board dismissed one issue, a question over Shell's ambient air quality analysis, because the petitioners had failed to raise this issue during the public comment period for the permit. And the board rejected all of the other issues because, the board said, the petitioners had failed to meet "their burden of demonstrating that (permit) review is warranted on any of the grounds presented." ●

Contact Alan Bailey at abailey@petroleumnews.com

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ENCANA

As many as six buyers

Eresman said the talks currently involve as many as six buyers to secure long-term sales contracts to help finance the liquefaction and export facility at Kitimat on the northern British Columbia coast.

The objective is to have offtake contracts in place for a significant portion of the projects volumes — currently targeting two trains of 700 million cubic feet per day each — allowing a final investment decision later this year, with the first LNG exports scheduled for late 2015 or early 2016, he said.

The partners are agreed that they will not make final investment decision until they have at least 80 percent of the LNG volumes under long-term arrangements, he said.

Of the U.S. shale prospects, Eresman said he would like to see a partnership comparable to Devon Energy's recent deal to give China's Sinopec a one-third interest in five developing fields for US$2.2 billion.

He indicated a process could be launched within the next month.

Encana's stake in northern Alberta's Duvernay shale, an early-stage gas liquids play, could also be part of the offering, Eresman said.

FirstEnergy Capital analyst Michael Dunn estimated Encana could extract about US$2 billion for its offering, adding to its recent C$2.9 billion deal to transfer 40 percent of its Cutbank Ridge gas field in British Columbia to Japan's Mitsubishi. ●

Contact Gary Park through publisher@petroleumnews.com

alaskaresource EDUCATION

Burggraf Resource Education Raffle & Silent Auction to benefit Alaska Resource Education
GRAND PRIZE- Two Alaska Airlines Roundtrip Tickets Won by: Duane Heyman
Drawing was at the conclusion of the Alaska Miners Association Convention Banquet on March 22, 2012

Scale Models: Hitachi and Volvo and Caterpillar Replicas
Donated By: Construction Machinery Industrial, CMI
Won By: Carrie Peterson, Jeff Shwarz, Dewey Hoffman, Kim Graham, Anne Baldridge

Two Travel Cases & Udelhoven Logo Gear
Donated By: Udelhoven Company
Won By: Dave Mael, Steve Borell, John Cole, Zoom

Fire Pit
Donated By: SteelFab
Won By: Randy Powelson

Polar Fleece Jacket
Donated By: Mikunda Cottrell
Won By: Unknown

Small Birch Basket by Mercy Cleveland
Donated By: NANA Regional Corporation
Won By: Ken Hughes

Logo Gear
Donated By: Pebble Partnership
Won By: Taff

Baseball Cap Collection
Donated By: Anonymous
Won By: Matt Petersen

Alaska Mountains Majesty 20X30 framed photograph
Donated By: Libbie Martin
Won By: Jane Kennedy

Two Lift Vouchers
Donated By: Hilltop Ski Area
Won By: Mike Cammach

Wine Glass Charms
Donated By: Anonymous
Won By: Delbert Parr

Two Caterpillar Jackets
Donated By: NC Machinery
Won By: Jimmy Evak

Knit Hat & Zipper Sweater
Donated By: Lynden
Won By: Jenn Adleman

Men's Hood Sweatshirt and Long Sleeved Shirt and Ladies Fleece Jacket
Donated By: Sunshine Custom Promotions
Won By: Mike Bell

Three Rivers Tour for Two: Mahay's Jet Boat Adventures
Donated By: Mahay's Jet Boat Adventures
Won By: Kit Lamborn

$50 Gift Certificate
Donated By: Bear and Moose Tooth
Won By: John Miscovich

$50 Gift Certificate
Donated By: Intuitions Day Spa
Won By: Lorna Shaw

Logo Gear
Donated By: Kinross Fort Knox
Won By: Chuck Hawley, Carrie Peterson

Two Commemorative Coins
Donated By: Kinross Fort Knox
Won By: Chris Kennedy

Logo Gear
Donated By: Rain for Rent
Won By: Dave Mael, John Shively

Polished Glacial Float Copper from Upper Peninsula, MI
Donated By: Alaska Prospectors
Won By: Tim Musgrove

AK Resource Mineral Kit
Donated By: AK Resource Education
Won By: Randy Powelson

Zach's Restaurant at Sophie Station Suites & Admission for two to Fountainhead Antique Auto Museum
Donated By: Sophie Station Suites
Won By: Lorna Shaw

Fleece Jacket, Vest and Two Beanies
Donated By: AMA
Won By: Clark Milne

AMA Logo Gear
Donated By: AMA
Won By: Paul Glavinovich, Lorna Shaw

Large Birch Basket by Mercy Cleveland
Donated By: NANA Regional Corporation
Won By: Fred Parady

Four NANA Logo Gift Baskets
Donated By: NANA Regional Corporation
Won By: Zoom, Dennis Steffy

$40 Gift Certificate
Donated By: Bradley House
Won By: Marleanna Hall

Lia Sophia Necklace
Donated By: Anonymous
Won By: Ken Hughes

Logo Gear
Donated By: Usibelli Coal Mine
Won By: Joel Stratman, John Cole, Dave Graham

Chainsaw
Donated By: Koncor Forest Products
Won By: Chris Kennedy

.33 Gold Nugget Diamond Pendant
Donated By: Oxford Metals
Won By: James Komadina

Banana Split Party for Four and Deserts for Year Punch Card
Donated By: Tastee Freez
Won By: Liz D'Amour

$100 Gift Certificate
Donated By: Allure Day Spa & Hair Design
Won By: Sharon Cox

Chena Hot Springs Overnight for Two with Pool Passes
Donated By: Chena Hot Springs
Won By: Karl Hanneman

Backpack, Sweatshirt and Beanie
Donated By: Red Dog
Won By: Meg Day

Men's Iditarod Vest and Hat
Women's Iditarod Vest and Hat
Donated By: Donlin Gold
Won By: Matt Petersen

Two Commemorative Coins
Donated By: Sumitomo Metal Mining Pogo LLC
Won By: Lois Ebel, Rick Rogers

Logo Gear
Donated By: Coeur Alaska, Kensington Gold Mine
Won By: Jim Duffield

$50 Gift Certificate
Donated By: Suite 100
Won By: Jenn Adelman

Two diamond willow vases
Donated By: Rain for Rent
Won By: Melissa Holt, Lorna Shaw

Sweatshirt, Long Sleeved T-shirt, Short Sleeved T-shirt
Donated By: Northern Air Cargo
Won By: Dave Graham

Jacket and Logo Gear
Donated By: International Tower Hill Mines Inc
Won By: Glen Faulkner

Photo of Beautiful "Sitka By The Sea
Donated By: Samson Tug and Barge
Won By: Patty Gentry

Fleece Blanket
Donated By: Nana Development Corporation
Won By: Sharon Cox

One Night Stay
Donated By: Westmark Hotel – Fairbanks
Won By: Arne Bakke

Rain for Rent Logo Gear
Donated By: Rain for Rent
Won By: Jim Duffield

Toy CAT Models & Cap
Donated By: MAPTS
Won By: Graham Neale

Calcite from Staunton, VA
Donated By: Mary Loose DeViney
Won By: Jenn Adelman

Alaska Railroad Poster
Donated By: Alaska Railroad
Won By: Drue Pearce

Kindle Touch
Donated By: Austin Powder Company
Won By: Graham Neale

170 Piece Tool Set
Donated By: Alaska Rubber
Won By: John Cole

Logo Gear
Donated By: Nalco Company
Won By: Kim Graham

Jackets and Hats
Donated By: NC Machinery
Won By: Arne Bakke

Waterproof Bag and Logo Gear
Donated By: Totem Trailer Express, Inc.
Won By: Paul Carrelo

Sample of Bituminous Coal from the Wishbone Hill Mine
Donated By: Usibelli Coal Mine
Won By: Arden Miller

Behind the Scenes Tour for Two
Donated By: Alaska SeaLife Center
Won By: Tom Covington

Carlile Truck and Shirt
Donated By: Carlile
Won By: Carrie Peterson

Minor Miner T-shirt and Coeur Travel Mug
Donated By: Coeur Alaska, Kensington Gold Mine and ARE
Won By: Jane Kennedy

Books by Jim Madonna
Donated By: Alaska Prospectors
Won By: Tim Musgrove

Copper/Silver Specimen from Upper Peninsula, MI
Donated By: Alaska Prospectors
Won By: Kevin Adler

Two Backpacks
Donated By: Connors Drilling LLC
Won By: Jane Kennedy, Kevin Lackey

Out Cry Item Winners

Tour for Two to Pebble Project
Donated By: Pebble Partnership
Won By: Don Krank

Ride in a CAT Haul Truck/Tour for Two to Usibelli
Donated By: Usibelli Coal Mine
Won By: Dave Graham

Tour For Two to Livengood Gold Project
Donated By: Tower Hill Mines
Won By: Clark Milne

Black Powder Cannon
Donated By: Howee's Machine Shop
Won By: John Miscovich

Burggraf Resource Education Tribute Sculpture
Donated By: Roger Burggraf
Won By: Construction Machinery Industrial, LLC

17" Handmade Native Eagle/Raven Drum/Beater
Donated By: Powtec
Won By: Wade Gies

Separett Model 9210, 12V, Waterless Toilet
Donated By: Lifewater Engineering Company
Won By: Graham Neale

Tour for Two to Fort Knox Mine
Donated By: Kinross Fort Knox
Won By: Rick Solie

.484 Troy Oz Nolan Creek Gold Nugget
Donated By: Roger Burggraf
Won By: David Hedderly-Smith

Tour for Two to Pogo Mine
Donated By: Sumitomo Metal Mining Pogo LLC
Won By: Mike Satre

Tour for Two to Niblack Project
Donated By: Niblack
Won By: Karl Hanneman

● EXPLORATION & PRODUCTION

Task force assesses shale oil needs

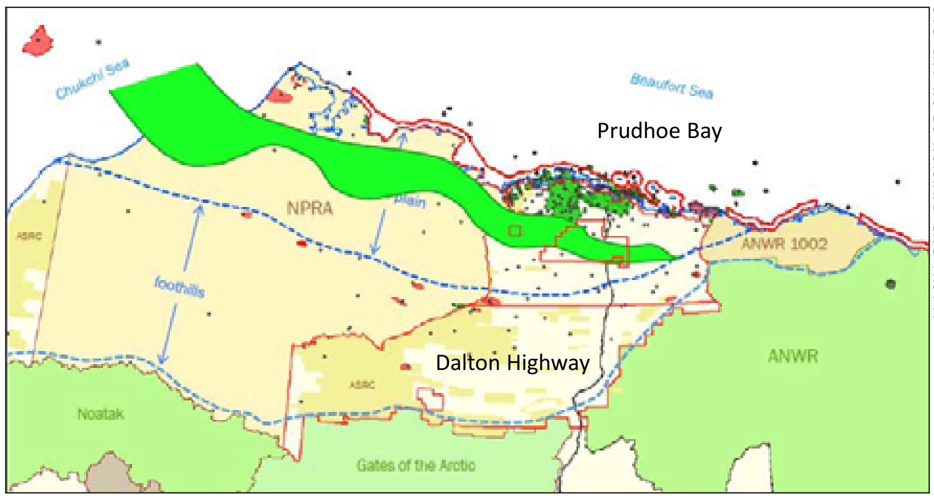
State agencies assess possible development scenarios and permitting needs if Alaska shale oil exploration proves successful

By ALAN BAILEY
Petroleum News

With Great Bear Petroleum moving toward drilling its first Alaska shale oil test well, investigating the possibility of producing oil direct from the prolific North Slope source rocks, the State of Alaska is taking an active interest in smoothing the route towards shale oil development, should shale oil production prove viable in the state.

400-mile fairway

The state views the region of highest Alaska shale oil potential as lying along a 400-mile-long fairway, running east from the Chukchi Sea coast into and across the area where Great Bear has its leases, to the south of the producing oil fields in the central North Slope, Greg Hobbs, a petroleum engineer with Alaska's Division of Oil and Gas, told Petroleum News March 30. That fairway is similar in size to the region occupied by the successful Eagle Ford shale oil and gas play in Texas, Hobbs said.



ALASKA DNR, DIVISION OF OIL AND GAS

Alaska's Division of Oil and Gas sees the best opportunities for shale oil development in northern Alaska in a 400-mile fairway extending east from the Chukchi Sea coast and running south of the Prudhoe Bay oil fields.

But, although the U.S. Geological Survey has estimated the possibility of anywhere up to 2 billion barrels of shale oil resources in northern Alaska, USGS has also said that until someone actually demonstrates that oil will flow from a North Slope source rock there remains the possibility of zero Alaska shale oil production.

On the other hand, with some of the most promising shale oil possibilities occurring in state land, with known high-quality oil originating from North Slope sources, and with the possibility of exploiting three different source rock intervals at single locations, the North Slope would seem to have a few things going for it when it comes to unconventional oil.

So what happens if shale oil development takes off?

Rapid development?

Experience in Texas has shown that shale oil can move into production mode as soon as three years from the drilling of the first successful proof-of-concept well, and the state wants to make sure that it is in a position to efficiently handle shale oil development in Alaska if the need arises, Hobbs said.

A task force consisting of eight to 10 people from state agencies has been meeting to evaluate what might be involved in North Slope shale oil development, Hobbs said. Currently the Alaska Department of Natural Resources, the Alaska Department of Fish & Game and the Alaska Department of Environmental Conservation have representatives on the task force, while the task force has also maintained contacts with the Alaska Department of Transportation & Public Facilities, and with the Alaska Oil and Gas Conservation Commission, Hobbs said.

The development of shale oil resources in Alaska would be of great benefit to the state in terms of its contribution to state revenues, especially given the current decline in Alaska oil production. So the state is anxious to see development move ahead but is also figuring out how to achieve the necessary environmental conservation and protection.

And, from an environmental and permitting perspective, the state sees four main issues that could prove challenging for Alaska shale oil development: the potential impacts on surface subsistence resources; the existence of wetlands in the areas of potential development; possible air quality issues; and the potential need for supplies of fresh water, Hobbs said.

The task force has held a meeting with representatives from the North Slope Borough and several federal agencies, to initiate a dialogue with these organizations over what might be involved in Alaska shale oil development. People at this meeting endorsed the state's views of the challenges facing development and also urged a need to recognize the potential impact of the infrastructure required to support the development activities, Hobbs said.

Intense drilling

Commercial success in a shale oil play hinges on development and production costs; oil productivity; and the price of oil, Hobbs said. And a key to the productivity part of this three-variable equation is the ability to drill many wells.

"The production of an oil shale play is maintained by the drilling," Hobbs said.

Essentially, although a shale oil well may initially produce oil at a high rate, perhaps at 1,000 barrels per day or more, pro-

see **SHALE OIL NEEDS** *page 15*

GOVERNMENT

BLM publishes draft NPR-A plan & EIS

Presents options with varying amounts of land withholding from development; will decide on preferred plan after public comments

A changing NPR-A planning scenario

According to the Bureau of Land Management's new draft integrated activity plan and environmental impact statement for the National Petroleum Reserve-Alaska, or NPR-A, BLM has recognized that in the time since the agency developed the existing plans for the northwestern and northeastern parts of the reserve several significant changes impacting planning assumptions have occurred.

For example, changing oil prices have caused the agency to use as planning assumptions an oil price of $180 per barrel and a natural gas price of $9.33 per thousand cubic feet, the draft document says.

Since earlier NPR-A plans were issued, the U.S. Geological Survey has substantially cut its estimate of undiscovered oil resources in NPR-A. And there has been an increasing interest in the potential for oil and gas development in the Chukchi Sea, with the resulting possible need for oil and gas pipelines from the Chukchi Sea coast across NPR-A to the central North Slope.

From an environmental perspective, the U.S. Fish and Wildlife Service has listed as threatened the polar bear, an animal that can be found in coastal areas of NPR-A. The National Marine Fisheries Service has proposed the listing of bearded and ringed seals, and has found that the listing of the Pacific walrus is warranted, the draft document says.

Compared with earlier NPR-A plans, BLM has updated and broadened its analysis of the potential cumulative impacts of development activities on the North Slope and has taken into account several new studies relating to the potential impacts of activities on surface resources, public health and climate change, the draft document says.

—ALAN BAILEY

By **ALAN BAILEY**
Petroleum News

As the next step in preparing a new plan for the management of the National Petroleum Reserve-Alaska, the nearly 23 million acre region of remote Arctic land in the extreme northwest of the state, the Bureau of Land Management has published a draft integrated activity plan and environmental impact statement for public review.

The public review period will last until June 1.

"The remarkable resources in the NPR-A call for a sound plan, which fully considers the input of local communities and Alaska Natives, and enables the nation to harness these domestic energy supplies with the right safeguards in place," said Bud Cribley, BLM-Alaska state director, on March 29 when announcing publication of the draft plan. "We need the public's input to ensure the best management plan is put in place for this area."

Entire NPR-A

This new plan encompasses the whole of the reserve — there have previously been separate plans for northeast NPR-A and northwest NPR-A, with no plan ever having been completed for the more southerly part of the region.

In February 2011 Cribley told Petroleum News that BLM was developing a unified plan for the entire reserve, to look at the region as a whole rather than piecemealing individual planning decisions for individual areas. And the executive summary for the draft plan now confirms that view.

"The BLM is developing the plan for the entire NPR-A to address the nation's need for production of more oil and gas through additional leasing in the NPR-A, and to protect surface values consistent with the exploration and development of oil and gas," the executive summary says. "This plan will address the entire NPR-A, and thus provide greater management consistency throughout the Petroleum Reserve than existing separate plans."

Differing priorities

In juggling the differing and sometimes contending priorities of hydrocarbon resource development and wildlife resource conservation, the draft BLM document presents four alternative plans, with the agency deferring a decision on which plan to adopt until after reviewing public comments on its plan options.

Much of the controversy in the NPR-A development versus conservation debate has focused on the extreme northeastern part of the reserve, close to the Beaufort Sea coast, where the oil and gas potential is thought to be especially high near the crest of a major geologic structure called the Barrow Arch, but where the large Teshekpuk Lake supports several Arctic wildlife species.

"Of particular interest is the potential impact of development near Teshekpuk Lake, which is considered to have high oil and gas value, but is also of great importance for waterfowl, caribou (for calving and relief from insects) and subsidence," the plan's executive summary says. "The lands near Teshekpuk Lake are currently deferred from leasing until 2018, and all alternatives will honor the leasing deferrals until their expiration."

With that caveat, the four alternatives in the plan all allow some level of oil and gas leasing while including varying amounts of land access restriction and other measures for environmental conservation.

No action alternative

The first alternative, characterized as the "no action" alternative, envisages business as usual, with decisions made in the current plans for northwest and northeast NPR-A being carried forward into the future. That would make available 13 million acres of land for future oil and gas lease sales. However, any lease sales for 1.57 million acres in the far northwest corner of the reserve, inland from the Chukchi Sea coast, would be deferred until at least January 2014, and leasing in 425,000 acres north and east of Teshekpuk Lake would be deferred until at least July 2018. No oil and gas leasing would take place in the southern part of the reserve.

And lands with high surface resource values, such as caribou calving areas, would be protected through stipulations such as development timing restrictions and the required setbacks of permanent oil and gas facilities from some lakes and other geographic features.

High protection

The second alternative emphasizes the protection of surface resources while making nearly 11 million acres of the reserve available for oil and gas leasing. While some land currently deferred from leasing would become available under this alternative after the current deferral dates, some of that deferred land would remain out of bounds. Two million acres would be added to the current protected area around Teshekpuk Lake. About 11.8 million acres of NPR-A in various areas viewed as having particular environmental sensitivity would be unavailable for oil and gas leasing, thus protecting the wilderness characteristics of the land, the draft document says.

And the second alternative involves recommending to the U.S. Congress that all or portions of 12 rivers should be included in the National Wild and Scenic Rivers System.

see **NPR-A PLAN** *page 11*

continued from page 10

NPR-A PLAN

Moderate protection

The third alternative would make 17.9 million acres of NPR-A land available for oil and gas leasing, while making selected coastal areas and 4.4 million acres in the far south of the reserve unavailable. Land currently deferred from leasing would become available after the current deferral dates. Within this alternative, BLM envisages developing a plan for obtaining gravel for the construction of roads and pads. However, although leasing would be allowed on much land near Teshekpuk Lake, the construction of production pads would not be allowed on this land.

"This may require directional/horizontal drilling for substantial distances to reach oil and gas resources," the draft BLM document says.

Alternative three also envisages a request to Congress to designate three rivers, including part of the Colville River, as "scenic" under the National Wild and Scenic Rivers System.

Protection measures only

The fourth alternative would make all NPR-A land, other than currently deferred land, available for future oil and gas leasing. Land with high surface resource value would be protected through stipulations, with some of these stipulations being less restrictive that in other plan alternatives. As in alternative three, this alternative includes the potential development of a plan for obtaining gravel. And the plan involves no new special protected area, or expansion to existing protected areas.

Alternatives two to four also consider the possibility of a future need for an infrastructure corridor across NPR-A, to enable the construction of facilities for the transportation of oil and gas from the Chukchi Sea, should oil and gas development in the Chukchi Sea take place. However, any plans for the development of Chukchi Sea related facilities would require reviews under the National Environmental Policy Act, the draft document says.

Eliminated options

BLM has eliminated from consideration any plan alternatives involving wilderness designations within NPR-A; the designation of wild lands; hard-rock or coal mining; the reduction or elimination of special environmental protection areas; the making of wild and scenic river designations for streams in northern portions of NPR-A, where NPR-A activity plans currently apply; the establishment of a national wildlife refuge in any part of NPR-A; and the prohibition of infrastructure development in support of Chukchi Sea oil and gas leases.

But, whichever alternative BLM ultimately chooses, the agency will continue to convey some federal land within NPR-A to Native Alaskans and Alaska Native corporations, under the terms of the Alaska Native Claims Settlement Act and the Native Allotment Act, the draft document says. BLM will also continue to conduct environmental studies in the reserve. The agency will continue to deal with the remediation of old, legacy wells in NPR-A, as well as work with responsible parties "to encourage the cleanup of contaminated and solid waste sites," the document says. And, potentially working with local residents and various government agencies, BLM will flesh out some details of NPR-A management, including the specification of arrangements for protecting special areas and the formation of cooperative agreements for environmental management. ●

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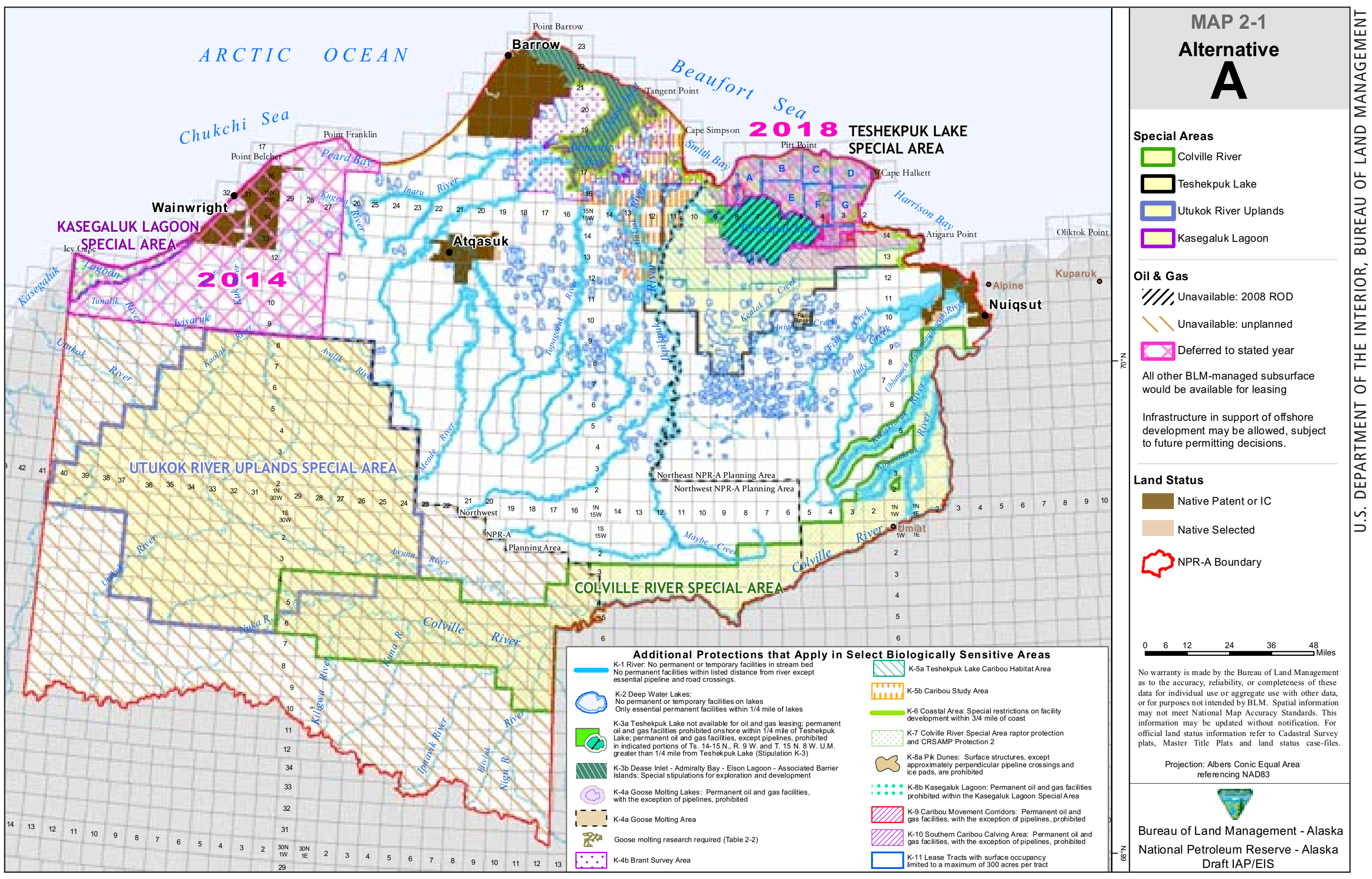

Scenario A, the "no action" option, in the Bureau of Land Management's draft integrated activity plan and environmental impact statement for the National Petroleum Reserve-Alaska would maintain the status quo, with the deferral of some areas from oil and gas leasing, no leasing in the southern part of the reserve and about 13 million acres available for future lease sales.

● NATURAL GAS

Gas line: 1982-2001: The Yukon Pacific era

Liquefied natural gas project would have shipped Alaska North Slope natural gas to Far East from liquefaction plant near Valdez

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

A new project pushed by a new company, Yukon Pacific Corp., revived interest in an Alaska gas pipeline in 1983.

Yukon Pacific was born amid doubts among some Alaskans that the Alaskan Northwest project through Canada would ever break ground — and over their dismay that the El Paso LNG project to California got jettisoned in favor of Alaskan Northwest in 1977.

BILL WHITE

The first seeds of Yukon Pacific were planted in 1982 as Alaskan Northwest Natural Gas Transportation Co. announced the latest postponement of its pipeline project. Lame-duck Gov. Jay Hammond appointed an eight-person task force to figure out now how best to turn Prudhoe Bay gas reserves into money. North Slope oil had been flowing for five years, and Alaskans wanted to see the natural gas move, too. The co-chairmen were two ex-governors who had been fans of the El Paso LNG project: Republican Wally Hickel and Democrat Bill Egan.

In January 1983, they delivered their new road map for bringing Alaska gas to market. Not surprisingly, it called for an LNG project — a pipeline to the Gulf of Alaska coast, with exports this time to Japan, South Korea and Taiwan, and possibly the U.S. West Coast, but not exclusively the West Coast as El Paso proposed. "It is unlikely that Alaska gas will be economically competitive in a free, uncontrolled U.S. market over the long term," the report predicted.

Yukon Pacific at a glance

PROJECT: Pipeline from Prudhoe Bay south to liquefied natural gas plant at Valdez, Alaska. LNG shipped by tanker to Asia.

SPONSORS: CSX Corp. became majority owner. Other investors included Wally Hickel and Supra Corp.

CAPACITY: 2.3 billion cubic feet a day

LENGTH: 797-mile Alaska pipeline

COST ESTIMATE (1996): $18 billion

SOURCE: U.S. Department of Energy; Yukon Pacific

This export-to-Asia concept dominated Alaska gas pipeline plans over the next 15 to 20 years.

With the task force's work done, Hickel quickly formed Yukon Pacific to push the project ahead. "The window is open now to the Japanese market, but it may not be open for long," Hickel said at the time, a refrain repeated over the ensuing years by LNG champions.

(Hickel held Yukon Pacific stock until 1991, shortly after he became governor again. He faced an accusation — the first ever against a governor under the state's 1987 Executive Branch Ethics Act — saying he improperly promoted the LNG project as governor while he owned Yukon Pacific stock. He divested the stock and the accusation was dropped. Hickel remained a brash LNG-project cheerleader until his death in 2010, even offering spirited endorsements of Alaska gubernatorial candidates in 2006 and 2010 who embraced his LNG project while denouncing all other gas pipeline ideas.)

The hope of those who launched Yukon Pacific in the early 1980s reflected the passion some Alaskans have with the LNG idea, a love affair that began with El Paso and continues today.

During the Yukon Pacific era, their optimism pushed aside the idea's Himalayan-sized market challenges and clung to a hope that a successful LNG project could offer Alaska a powerful and lasting economic kick.

World's largest LNG plant

As conceived, the new Yukon Pacific LNG project was similar in size to El Paso's.

The pipeline would span roughly 800 miles, cost $14.3 billion (1982 dollars) not counting tankers, and it would carry up to 2.83 billion cubic feet a day of natural gas. It would be constructed in phases and, when fully built out, export 1.9 bcf a day (14.5 million tons a year) after consuming some gas during the liquefaction. It would be the world's largest LNG plant.

But besides targeting Asia, the original Yukon Pacific project diverged from the earlier El Paso plan in important ways:

The pipeline would go from Prudhoe Bay to Nikiski on the Kenai Peninsula southwest of Anchorage, not to Gravina Point near Cordova. Nikiski already was home to a 14-year-old LNG export plant, the only one in the United States, but the new plant would be about 10 times larger. Within a few years, the proposal's terminus shifted eastward to Valdez, so the gas pipeline would run parallel to the trans-Alaska oil pipeline from Prudhoe Bay to tidewater.

JUDY PATRICK

WALTER HICKEL

The pipeline could carry the full stream of Prudhoe Bay gas, not just methane but also such gas liquids as propane and butane as well as some unusual ingredients — carbon dioxide and other contaminants usually removed from pipeline gas.

The gas liquids would give the pipeline something extra to sell, making it more financially viable. Although extracting gas liquids from the methane at tidewater would be expensive, the liquids could be exported, proponents said, fetching higher market prices than methane gets.

Piping contaminants from Prudhoe Bay is dicier. They're seldom found beyond trace amounts in pipeline gas. Carbon dioxide and hydrogen sulfide, both of which are present in Prudhoe gas, are called acid gases because they form acids or acidic solutions and can corrode a steel pipeline when water is present. Prudhoe gas is quite acidic — 12 to 13 percent of the gas is carbon dioxide.

The Alaskan Northwest pipeline project would have removed the contaminants at Prudhoe Bay, before gas enters the pipeline. So would the TransCanada/ExxonMobil gas pipeline proposal currently being worked; once removed at Prudhoe, the carbon dioxide would be injected back into the Prudhoe reservoir to help produce more oil.

But Yukon Pacific proposed to pipe the contaminants and extract them at Nikiski, where the plant would be cheaper to build. Of course, that would leave unresolved the chore of carbon dioxide disposal. Yukon Pacific had some ideas about that: Sell it to petrochemical plants as feedstock, spike it with other hydrocarbons to produce low-grade fuel, shoot it into nearby Cook Inlet oil fields to scrub out more crude, or vent the gas into the atmosphere "in tall stacks."

Paperwork in order

The Yukon Pacific project percolated along through the 1980s and early 1990s.

The project design was refined somewhat. Besides moving the pipeline terminus to Valdez, Yukon Pacific decided to remove carbon dioxide and other contaminants at Prudhoe Bay after all. The company also scaled back the pipeline volume to 2.3 bcf a day — allowing export of 1.8 bcf a day on average after using some of the gas in compressors to liquefy it.

In 1986 a deep pocket became part owner with Hickel: Texas Gas Transmission Inc. a subsidiary of Lower 48 railroad and shipping giant CSX Corp. Texas Gas was quite familiar with Alaska gas pipeline efforts; it once was part of the Alaskan Northwest consortium that pushed the 1970s-era pipeline project. The company dropped out of Alaskan

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PIPELINE WARS

Northwest in 1981 and CSX bought it in 1983.

Besides Hickel and CSX, another Yukon Pacific partner was Supra Corp., a venture of Robert O. Anderson, who headed Arco during the Prudhoe Bay discovery.

But Yukon Pacific really became CSX's show. The same year that CSX bought into Yukon Pacific, it also acquired Sealand, a major ocean-going cargo carrier serving Alaska that presumably would haul materials for the LNG project. By 1988, CSX was majority owner of Yukon Pacific. (CSX divested of Texas Gas in 1989 and of Sealand in 1999.)

In 1988, Yukon Pacific obtained a right of way across federal land for most of its pipeline route. That same year, President Ronald Reagan issued a needed finding that exporting North Slope gas would not hurt Lower 48 consumers. The U.S. natural gas shortages of the 1970s were gone — price and pipeline deregulation triggered drilling that found trillions of cubic feet of new gas reserves.

In 1989, the U.S. Department of Energy authorized Yukon Pacific to export of up to 14 million metric tons of LNG per year (about 1.8 bcf a day) to Japan, South Korea and Taiwan.

Both this export authorization and the presidential finding contained language that cautioned the government wasn't favoring the Yukon Pacific project over a pipeline through Canada. Officials in Canada and executives with Alaskan Northwest had expressed worry that the Yukon Pacific project might kill the Canada line. "The DOE is not dictating that a specific project should be undertaken for developing North Slope natural gas. The approval neither commits any natural gas supplies to Yukon Pacific nor creates any regulatory impediments to other North Slope natural gas projects, including ANGTS (Alaska Natural Gas Transportation System, the Alaskan Northwest-sponsored pipeline through Canada authorized in 1977). Rather, the approval is intended to spur competition to develop North Slope natural gas efficiently, with the marketplace determining the course of development," the DOE order said.

Year-by-year Yukon Pacific obtained the paperwork needed for its LNG project.

But paperwork got the company only so far. It never had gas for its pipeline to carry.

Elephant in a dog house

Yukon Pacific executives often railed at how North Slope producers were stymieing the LNG project by not selling their gas.

Alaska gas pipeline 1982-2001

1982 – Proposed Alaskan Northwest project along Alaska Highway into Canada postponed. Two former Alaska governors, Wally Hickel and Bill Egan, head state task force to find a pipeline solution.

1983 – Task force recommends 800-mile pipeline to Alaska's Pacific Coast, with LNG exports to West Coast or Asia. Hickel forms Yukon Pacific Corp. to develop this project.

1986 – Lower 48 transportation giant CSX invests in Yukon Pacific.

1988 – CSX becomes majority owner of Yukon Pacific.

1988-1989 – Yukon Pacific obtains right of way across federal land and federal export authorization. Target market is Asia.

Early 1990s – Yukon Pacific says it has tentative deals with LNG buyers in South Korea and Taiwan but never achieves final contracts.

1990s – LNG prices remain low, averaging $3.52 per million Btu during decade in Japan, too low to make project profitable.

2001 – As three major North Slope producers look into their own pipeline project to Lower 48, Yukon Pacific slashes staff.

Between 2008 and 2011, Yukon Pacific loses bid to extend conditional right of way across state land, fails to get federal authorization extended for its Valdez LNG plant, and gives up federal-land right of way.

The whole story is more faceted. Natural gas does rise up wells with crude oil. But the producers injected the gas back underground to scour more oil from Prudhoe and nearby fields. This not only was prudent because the gas could be saved for later while coaxing much more valuable oil to the surface. But the practice was mandated by state regulators charged with making sure Alaskans got the highest value for their resources.

Beyond that, Yukon Pacific's project was handicapped by two fatal flaws: It would produce too much LNG and the gas would be too expensive.

Yukon Pacific's project would have exported 14 million metric tons a year of LNG. That was too much for the small but growing LNG market to absorb easily. In 1990, demand from the nine countries worldwide that imported LNG totaled about 50 million metric tons, according to the International Gas Union. Yukon Pacific would have boosted global LNG supplies by 28 percent. Demand wasn't growing that fast, and other LNG makers were keeping pace by expanding their less-expensive production. Yukon Pacific was trying to stuff an elephant into a doghouse.

Price was another barrier. The Yukon Pacific project called for piping gas 800 miles, superchilling it into a liquid and shipping it to Asia. The Japan price for LNG topped $5 per thousand cubic feet the year Hickel conceived Yukon Pacific. Hickel's group figured it could hold its costs to $5.67 to $7.16 per thousand cubic feet of gas. It forecasted LNG would be priced at $7.89 in 1988 in Asia, with 3 percent annual price inflation after that. If Yukon Pacific could ward off big cost overruns on its project, everyone would make money.

But the Asian LNG price was linked to oil, not inflation. And oil prices were falling. In 1988, the average price in Japan was $3.34, according to the 2011 BP Statistical Review of World Energy. The price didn't get much higher for a long time. From 1987 through 1999, the LNG price in Japan averaged $3.47. Other LNG projects in Asia could hit that price and make money. With LNG sold under decades-long contracts, the price risk for buyers was too great and Yukon Pacific's project couldn't complete.

Yukon Pacific dream fades

Still, determined optimism defined the public façade of Yukon Pacific executives.

"We agree with the view that the world is awash in natural gas," one said in 1986. "But we disagree with the view that waiting (for gas prices to strengthen) is the way to go. That won't make anything happen."

In 1987, a Yukon Pacific executive hopefully cited new forecasts that annual LNG demand in Japan, South Korea and Taiwan together would swell by 7.5 million to 8.5 million metric tons by the mid-1990s. But even if Yukon Pacific captured 100 percent of that growth, it would have fallen far short of the 14 million tons it needed to sell.

In 1989, an executive said his company was "dealing very seriously" with a South Korea buyer that could buy 3 million tons a year. In 1990 he said he had a letter of intent — a document that precedes a contract — from a Korean buyer for 2 million tons a year with an indication the company might want an additional 2 million.

In 1992, a Yukon Pacific executive said a Taiwan purchaser had signed a "memorandum of intent" for a confidential amount of gas, adding to a tentative commitment from a South Korea buyer for 2 million to 5 million metric tons a year. But the company never could put together a solid deal.

Asian gas buyers and government officials encouraged Yukon Pacific to build the project. A more diverse set of LNG sellers could help give them the reliability of supply they desired while bringing price competition to the market. But encouraging Yukon Pacific was not the same as becoming a customer.

A 1991 article in the Anchorage Daily News outlined the problem: Yukon Pacific would need to sell 8 million tons a year to Japan — about one-seventh of that nation's expected need. "The standard contract is on a 'take or pay' basis, which means once they contract for the gas, they pay for it whether or not they need it. Business leaders here (in Japan) believe their gas market will grow rapidly over the next several years, but they're not willing to bet billions of yen on it just in case they're wrong." The reporter interviewed Tokyo Electric Power Co.'s fuel department chief, who said Japanese companies can buy more gas when they need it from Indonesia, Malaysia or elsewhere, places that can boost their LNG production quickly and cheaply. The Yukon Pacific project was burdened by the cost of building an 800-mile pipeline.

Still Yukon executives persevered. In 1996, they released a study that concluded their LNG export project, now estimated to cost $18.4 billion, could turn a profit, pour billions in taxes and royalties into the state treasury and result in hundreds of new long-term jobs.

Not so fast, came the chilly response from North Slope producers. Look at the assumptions, they said: The project works only if it can lock in buyers for 30 years willing to pay 12 percent more than 1996 market prices, with the price escalating 3 percent a year after that. A senior Atlantic Richfield executive termed the assumptions "aggressively optimistic."

"It doesn't help the project progress if we're painting an unrealistic picture," he said.

By then, Atlantic Richfield and BP, the two companies that then operated the Prudhoe Bay field, were starting to blow life into their own long-dormant hopes for a North Slope gas pipeline.

Those companies were gazing into a future where Prudhoe Bay crude production will have fallen so much that it made sense to start piping some natural gas off the North Slope instead of reinjecting it to produce more oil.

Maybe the market will be ready for a gas pipeline by 2005 or 2010, they said. Possibly it would be an LNG project, they said.

Big oil was sucking the wind out of

see **PIPELINE WARS** *page 14*

● NATURAL GAS

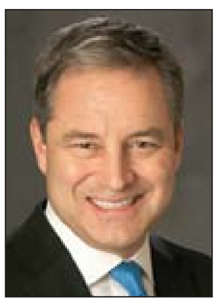
Gas players aligning, need fiscal terms

Exxon, Conoco, BP, TransCanada tell governor they will look at LNG project; say 'right business climate' needed to unlock the resource

By KRISTEN NELSON

Petroleum News

In October, Alaska Gov. Sean Parnell called for alignment of the North Slope producers around a gas pipeline project to tidewater. In a March 30 press conference, when the Point Thomson settlement was announced, Parnell said there were two milestones toward a gas line — the litigation settlement over a field containing some 25 percent of known natural gas on the North Slope and alignment of the producers around a gas pipeline project to tidewater (see story on settlement on page 1 of this issue).



GOV. SEAN PARNELL

The settlement makes it clear that the state's top priority for Point Thomson is use of the gas.

"The settlement incentivizes efforts to commercialize the North Slope's vast gas resources by: helping to position Point Thomson for gas development; facilitating the alignment of interests between the major North Slope producers and the state; and installing critical infrastructure for gas sales," the Alaska Department of Natural Resources said in a fact sheet on the settlement.

Next generation of resource development

In a March 30 letter to Parnell, the CEOs of ExxonMobil, ConocoPhillips and BP said the companies are making progress on "the next generation of North Slope resource development."

That resource is natural gas, they said, which has been used to date to enhance North Slope oil production: "However, under the right business climate, the full commercial potential of this world-class resource can be unlocked."

In a March 30 letter to Parnell, the CEOs of ExxonMobil, ConocoPhillips and BP said the companies are making progress on "the next generation of North Slope resource development."

ExxonMobil and TransCanada have been working on a project to take North Slope gas to markets in the Lower 48 under the framework of the Alaska Gasline Inducement Act, or AGIA, but there has been general agreement that alignment between all of the North Slope producers, a pipeline company and the state will be necessary to commercialize North Slope natural gas.

Because of a huge supply of natural gas available currently in the Lower 48 and higher market prices in the Far East, Parnell has called for alignment around a liquefied natural gas project at tidewater in Southcentral Alaska.

The agreement is just the first step, Parnell said at a March 30 press conference.

LNG alternative

In their March 30 letter, CEOs of the major North Slope producers laid out some of the work they see ahead to achieve alignment under an AGIA framework.

They said commercialization of the 35 trillion cubic feet of discovered natural gas on Alaska's North Slope "will not be easy."

With a rapidly evolving market, a large-scale LNG export from Southcentral Alaska "will be assessed as an alternative to gas line exports through Alberta," the letter says.

The companies said they are "working together on the gas commercialization project concept selection, which would include an associated timeline and an assessment of major project components including in-state pipeline routes and capacities, global LNG trends, and LNG tidewater site locations, among others."

A March 30 press release by the companies included TransCanada, which is working on the Alaska Pipeline Project (as the state's AGIA licensee) in partnership with ExxonMobil.

Challenges

"There are many challenges and issues that must be resolved, and we cannot do it alone. Unprecedented commitments of capital for gas development will require competitive and stable fiscal terms with the State of Alaska first be established," the companies said in their letter to Parnell.

They noted that stable fiscal arrangements have opened other opportunities around the world, "and will play a pivotal role in making Alaska competitive in the global market and unlocking the economic potential of North Slope resources."

Parnell said in the March 30 press conference that the companies intend to complete concept selection work this fall and said the state will be monitoring that progress.

The benchmarks laid out by Parnell in his January 2012 state-of-the-state address included settlement of the Point Thomson litigation and formal alignment of the producers under an AGIA framework, including work on a large-diameter LNG line to tidewater by the second quarter of 2012; completion of discussions with the Alaska Gasline Development Corp. on the potential to consolidate projects by the third quarter of 2012; and hardening of numbers for an Alaska LNG project, including identifying a pipeline project and a work schedule by the third quarter.

He said that if those benchmarks are met that the 2013 Legislature would take up gas tax legislation designed to move the project forward. Parnell has said in the past that he won't negotiate separately with the players on a fiscal system for gas, but only with a project. ●

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PIPELINE WARS

Yukon Pacific's sails. With its momentum fading the company slashed its staff in 2001 and slowly started packing up.

In 2008, Yukon lost its conditional right of way that would let the pipeline cross state land. In 2010, the Federal Energy Regulatory Commission denied Yukon Pacific's request for more time to build an LNG plant. In October 2011, the company gave up its federal right-of-way grant.

Despite Yukon Pacific's demise, LNG fever held strong through the years among certain Alaska leaders.

In 1998, state legislators in Juneau passed the Stranded Gas Act designed to provide state incentives to boost prospects of an LNG project. But only an LNG export project; no one else need apply.

The law didn't help; no one asked to negotiate fiscal terms with the state. The LNG dream went on life-support.

But the Alaska gas pipeline project was entering a new phase. The new burst of life came courtesy of the North Slope producers and their resurrected ideas for a pipeline, and a new concern that the nation was running short of natural gas. ●

Next: 2000 to today — interest in Alaska's gas revives

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/The-Yukon-Pacific-era-1982-2001.

● ENVIRONMENT & SAFETY

GAO questions Shell's contingency plans

Says that use of an oil spill containment system in Arctic waters would involve risks resulting from sea ice and low temperatures

By ALAN BAILEY
Petroleum News

The Government Accountability Office, or GAO, the watchdog agency that investigates federal government spending, has published a report examining progress in government oversight of offshore drilling safety following the 2010 Deepwater Horizon disaster in the Gulf of Mexico. The GAO report says that progress has been made in following up on lessons learned from the 2010 oil spill. However, the report also says that the Department of the Interior needs to set a timeframe for the inclusion of new oil spill containment systems into unannounced spill drills, and questions the practicalities of using a containment system in the event of a well blowout during Shell's planned Alaska Arctic offshore drilling operations.

New system

Shell is building a containment and capping system that the company says could be placed over an out-of-control well in the event of a blowout preventer failure, enabling oil from the well to be collected in a surface vessel and allowing the oil flow to be stopped while the well is brought under control. The technology is based on the system that was eventually used to contain the flow of oil from the Macondo well in the Gulf disaster.

"Subsea drilling operations in Alaska will face operating conditions that greatly differ from those in the Gulf of Mexico and may pose unique risks," the GAO report says. "For example, the Beaufort and Chukchi seas are inside the Arctic Circle, with cold and icy conditions for much of the year and with few daylight hours during the winter."

Shell proposes to drill between July 15 and Oct. 31 — if a blowout were to occur late in the drilling season, ice conditions in November and December could make well containment challenging, the report says. And, although Shell plans to recess its wellheads and blowout preventers into the seafloor, this arrangement does not eliminate the possibility of sea ice obstructing or damaging the containment and capping equipment, the report says.

The report acknowledges Shell's plan to station its containment and capping system offshore during its Arctic drilling operations but questions the practicalities of transporting additional personnel into the region to handle a well blowout, should the need arise. Harbors, airstrips and hotels are sparse and are located relatively far from drilling sites, the report says. Moreover, there are few additional resources available for responding to a subsea blowout in the event that Shell's capabilities prove insufficient, the report says.

Interior response

In statements made in response to the GAO report, the Department of the Interior said that new agencies within Interior that have replaced the former Minerals Management Service have instituted tough new regulatory and permitting standards.

"For the recent oil spill response plan approvals in the Arctic, the operator proposed a well control containment capability that consists of a combination of a subsea capping stack, and surface separation equipment that will be located on a newly-built containment vessel, all of which will be inspected by BSEE (the Bureau of Safety and Environmental Enforcement) prior to the beginning of any proposed operations," Interior said. "BSEE conducted exhaustive reviews of the plans and continues to hold the operators accountable with additional exercises, reviews and inspections to ensure that all personnel and equipment are positioned and ready, if needed. In addition, recent unannounced spill drills have included engagement of the well containment consortia." ●

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SHALE OIL NEEDS

duction tends to decline rapidly, typically stabilizing at a more long-term rate of perhaps 100 to 200 barrels per day. In the Bakken play in North Dakota, for example, total production from the play is currently running at about 488,000 barrels per day from 6,000 wells, indicating an average daily well production of just 80 barrels, Hobbs said.

The need for a continuous drilling program to sustain production on Alaska's North Slope may require the packaging of permits, enabling multiple drilling operations to be permitted in batches, rather than individually, without losing the regulatory authority and oversight from the various agencies involved.

"Given the fact that it is very much an assembly line type development, could a group of (drilling) pads be permitted together? Could an air quality permit cover a series of operations?" Hobbs questioned, commenting that this is one of the permitting issues that the task force is examining.

However, Hobbs does not think that the type of single-well drilling pad used in the Bakken, for example, would be practical in the tundra of northern Alaska, given the intense amount of drilling required.

"In my opinion it would be cost-prohibitive to try to do a development in Alaska like they're doing in the Lower 48," Hobbs said. "They're not contending with wetlands there."

Alaska model

Instead, Hobbs has proposed a multi-well pad scheme for possible North Slope shale oil development. This model is entirely hypothetical and may not represent what a developer would actually do, Hobbs emphasized. However, the model can provide some insights into what might be involved, and how the permitting of a development might be carried out, he said.

Hobbs envisages a series of 840-foot by 420-foot gravel pads, perhaps connected by a gravel road, extending east-west through a shale oil development area from the existing North Slope Haul road. Each pad would accommodate 12 wellheads, with each well running at a steep angle down to the oil source before splitting into two horizontal, lateral well bores. The result would be 24 lateral wells penetrating subsurface source rock in an area centered under the pad and extending four miles in an east-west direction and three miles in a north-south direction.

To access the entire extent of subsurface source rock across a leased area, the pads would be four miles apart in an east-west direction, with similar east-west lines of pads developed at three-mile intervals, north and south.

One pad per year

Hobbs' concept involves a single rig drilling all of the wells for a single pad during a single year. While that drilling is in progress, the next pad and its associated gravel road would be constructed, ready for drilling in the following year. Thus, year-by-year, the development would move out across the area of the shale oil play, along a development corridor.

The wells would probably go to depths of around 10,000 feet, with 10,000-foot horizontal laterals, similar to deviated and horizontal wells already drilled on the North Slope, Hobbs said.

"I don't see a whole lot of difference in well design," he said.

And, although shale oil production depends on the hydraulic fracturing of the oil source rock, companies operating in Alaska already have extensive experience in using "fracking" techniques — about 25 percent of the oil wells that have been drilled in Alaska have used hydraulic fracturing to improve productivity, Hobbs said.

With this type of development, it would potentially be possible to use relatively lightweight, truckable production facilities, with a high capacity facility moved to serve pads that have come newly online and which have the high initial production rates characteristic of shale oil development. The more mature pads could perhaps be hooked up to smaller, lower capacity systems, Hobbs said. ●

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Oil Patch Bits

Solstice Advertising welcomes new talent to team

Solstice Advertising said April 2 that it has added two new team members to its award-winning marketing and advertising staff.

Web Technician Paul Davidson has spent 15 years working in the communications industry and has a strong background in creative technology. He previously managed the creative production workflow for Leo Burnett/Capps Digital in Illinois and has developed digital collaboration systems for global agency networks. Davidson has a wide range of skills that allow him to generate innovative ideas during every step of the creative process. He holds a bachelor's degree in English from the University of Colorado.

PAUL DAVIDSON

JACKIE BARTZ

New Solstice copywriter Jackie Bartz brings her creative writing and storytelling skills from the local broadcast arena. As a reporter for KTUU, Alaska's most watched news station, she traveled all over the state covering a range of topics and issues important to Alaskans. Her experience in news makes her no stranger to deadlines, and crafting creative, compelling copy at the drop of a dime. Bartz holds a bachelor's degree in broadcast journalism from the University of Montana.

Solstice is pleased to have Davidson and Bartz as new additions to its professional and skilled communications team, bringing shine to each and every client.

Air Liquide acquires renewable natural gas plant

As reported on the Market Watch website, Air Liquide Advanced Technologies U.S. LLC, Air Liquide, said March 8 that it has purchased the renewable natural gas assets of Georecover-Live Oak, LLC, a subsidiary of Jacoby Energy Development Inc., a Georgia-based company which recovers and processes landfill exhaust gas into renewable natural gas, sometimes referred to as biomethane.

Included in the sale was the company's landfill gas processing facility in Conley, Ga., near Atlanta. The Conley facility, which uses Air Liquide's proprietary MEDAL membrane technology, processes all of the landfill gas from the adjacent Live Oak landfill, generating up to 1,500 MWh of renewable natural gas daily to be transported via pipeline. This natural gas can be used as a feedstock for renewable hydrogen, renewable compressed or liquefied natural gas or to generate renewable electricity.

The acquisition demonstrates the Air Liquide Group's global strategy of bringing sustainable,

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Companies involved in Alaska and northern Canada's oil and gas industry

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

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THOMSON DEAL

believe the terms of the settlement will finally deliver production.

It's clear from the dense, 85-page settlement agreement that both sides — the state and the oil companies — made huge concessions.

The deal also spawned a reshuffling of Point Thomson ownership with Chevron assigning its sizeable interest to ExxonMobil. The other major owners are BP and ConocoPhillips.

In a press conference in Anchorage to announce the deal, Alaska Gov. Sean Parnell said settling the Point Thomson matter was one of his priorities.

"Point Thomson is the largest undeveloped oil and gas field in Alaska, holding 25 percent of the North Slope's known gas," Parnell said. "Many administrations have struggled over the lack of production from this field, where the initial leases were granted 40 years ago. When the state decided to take those leases back, it triggered a significant but important legal battle with the producers that has already spanned three different administrations."

In a joint letter to Parnell, the chief executives of ExxonMobil, BP and ConocoPhillips said that with the settlement now finalized, "our companies are moving forward, as participating co-venturers, with the initial development phase at Point Thomson."

'Earning' acreage

The Point Thomson unit is 60 miles east of Prudhoe Bay, along the Beaufort Sea coast. The unit encompasses 38 state leases on 93,291 acres.

The Point Thomson conflict started in 2005, when the administration of then-Gov. Frank Murkowski began taking steps to terminate the unit and invalidate the leases.

The oil companies were fighting these actions administratively and in court.

As part of the settlement, the state is fully reinstating the unit as well as the leases.

Now the Point Thomson leaseholders are "on the clock," state Natural Resources Commissioner Dan Sullivan said in an interview with Petroleum News.

The companies must start performing, and soon, to "earn" the leases, Sullivan said, or risk losing potentially all of the acreage at Point Thomson "without appeal."

The deal lays out a complex schedule for starting, and then increasing, production from Point Thomson.

The first step, dubbed the "initial production system," or IPS, involves putting two wells, known as PTU-15 and PTU-16, on production by the end of the 2015-16 winter season. These wells on Point Thomson's central work pad will be part of a "gas cycling" operation whereby condensate, a liquid hydrocarbon, is collected with the residual dry gas injected back underground for storage. Initial production is to be 10,000 barrels per day.

The IPS also entails construction of a 22-mile pipeline to carry the condensate west to the existing Badami field. Ultimately it will flow into the trans-Alaska oil pipeline.

If the IPS sounds familiar, it's because ExxonMobil made an "unconditional commitment" back in 2008 to produce 10,000 barrels a day of condensate. Even as the state and ExxonMobil fought over Point Thomson, the company went ahead and drilled the two wells.

In a court filing in January 2010, the state's lawyers suggested 10,000 barrels was "a minimal trickle of production." Indeed, it's a small volume when measured against total North Slope production of around 600,000 barrels per day.

Sullivan, formerly Alaska's attorney general, said he and other state negotiators did consider "going for something bigger."

They concluded the fastest path to first production was to go with the 10,000-barrel project ExxonMobil already had in the works. Federal and state permitting is well along for the project, and starting over with a different or bigger project would squander time and effort, Sullivan said.

He added that the common carrier pipeline will have a capacity of 70,000 barrels per day, thus serving as a vital asset for developing highly prospective oil and gas acreage on the eastern North Slope.

Expanded development

At the IPS stage, the settlement also calls for drilling another well on Point Thomson's west pad by the end of the 2016-17 winter season. And the companies must permit two additional wells for the east pad.

Once the IPS is on production, the companies must then turn their attention to three alternatives for full-field development.

The state's fondest alternative is a "major gas sale," a project to develop Point Thomson's estimated 8 trillion cubic feet of gas. However, this would require a multibillion-dollar North Slope gas pipeline, a project the industry to date has regarded as too expensive and risky.

If the companies fail to sanction, or green light, a major gas sale project by June 2016, they must begin engineering and permitting to expand Point Thomson production under the second or third alternatives.

The second alternative requires the companies to produce a minimum of 30,000 barrels of liquids per day, or face losing some unit acreage.

The third alternative is more creative, involving a "complex reservoir integration" between Prudhoe Bay and Point Thomson, says a state-prepared settlement overview. This would involve transporting dry gas from Point Thomson to the Prudhoe Bay field for injection underground, boosting crude recovery from the nation's largest oil field.

One other element of the settlement concerns Point Thomson's Brookian oil accumulation. The companies must commit to production by 2018 or they lose the Brookian acreage.

Overall, if ExxonMobil and its partners balk on IPS production and fail to sanction a major gas sale by 2019, then the unit terminates and all acreage automatically returns to the state "without appeal."

That includes leases with wells the state certified years ago as "capable of producing in paying quantities."

'Sledgehammer'

The settlement is profound in a number of ways. As already mentioned, the state made a major concession in reinstating the disputed unit and leases.

The companies, in turn, made a huge concession with a provision in the deal vacating a Jan. 11, 2010, ruling in Superior Court that reversed, on procedural grounds, the state's termination of the Point Thomson unit.

It was that decision that forced the state, clearly wounded, to make an unusual interlocutory appeal to the Alaska Supreme Court. On Feb. 8, the justices heard oral argument on the case at Anchorage's West High School.

The Supreme Court hasn't ruled on the case — and won't. At the joint request of the state and the oil companies, the court dismissed the appeal on March 29, the day before the settlement was announced.

The tedious language of the settlement agreement suggests that Point Thomson could again become the subject of court and administrative wrangling, or arbitration.

But Sullivan says the document packs "sledgehammer" provisions for the companies to produce or else lose acreage. The language the companies have agreed to would kill any court challenge they might bring, he said.

One reason ExxonMobil has cited for lack of Point Thomson development is the field's extraordinary reservoir pressure, among other technical issues.

State officials sought to verify that at the outset of settlement talks with ExxonMobil.

"We went down to Houston for about a week and got access to their data room," said Jonathan Katchen, a Department of Natural Resources official who worked on the settlement. Later, he said, ExxonMobil brought up "a truckload of documents" to its Anchorage offices for review.

Katchen, working in the state Department of Law at the time, said it was clear to him and DNR staffers that Point Thomson does, in fact, present real challenges.

Thus, state documents note that the IPS will "help determine the feasibility of" expanding liquids production from Point Thomson.

Chevron's retreat

One company that held a major stake in Point Thomson, and was involved in the court fight to preserve the unit and leases, is now bowing out.

Chevron spokesman Russell Johnson told Petroleum News in an April 3 email that his company has agreed to assign its interest in Point Thomson to ExxonMobil. Terms of the agreement are confidential, he said.

"Chevron has elected to exit Point Thomson," Johnson's email said. "Going forward, Chevron will not be a part of that development. In evaluating the opportunity, we determined that Point Thomson is unable to compete for capital with other global opportunities in Chevron's portfolio. Chevron continues to invest in Alaska through its minority interests in the Prudhoe Bay, Kuparuk and Endicott fields, as well as the TransAlaska Pipeline."

At the end of 2011, Chevron closed a deal to sell its oil and gas assets in Alaska's Cook Inlet basin to Hilcorp Energy Co.

Assignment of Chevron's 11.6 percent working interest in Point Thomson will bump up ExxonMobil's share to 68.3 percent. BP owns 27.2 percent and ConocoPhillips 3.2 percent, with 20 others combining for 1.2 percent.●

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VESSEL INJUNCTION

sel operations; preventing access to or egress from the vessels; or threatening or endangering people using the vessels, the court order says.

Judge Gleason also banned Greenpeace activists from entering safety zones ranging from 500 to 1,000 meters around the vessels when the vessels are in transit.

In February Shell asked the District Court to issue a restraining order against Greenpeace, which has already protested against the company's Arctic drilling plans by occupying the Noble Discoverer in New Zealand and by occupying two icebreakers in Finland that had been contracted for Shell's operations. Gleason responded by issuing a temporary restraining order, banning Greenpeace from trespassing on Shell's drilling vessels. The injunction issued March 28 supersedes that restraining order.

Case continues

However, the court case against Greenpeace is still continuing, with Judge Gleason still to rule on some motions that Greenpeace has raised. Consequently, the court may at some point issue a supplemental or revised injunction, the court order says.

Among the claims still to be ruled on is a question of District Court jurisdiction over activities in the U.S. Exclusive Economic Zone, or EEZ, where Shell will be drilling, as distinct from U.S. territorial waters and harbors. Gleason says that the court will rule on this question before Shell's vessels start to operate in the EEZ. Similarly the court will rule in due course on a question of court jurisdiction over activities at aviation facilities in the northern Alaska town of Barrow, where Shell will presumably base the aviation operations in support of its drilling fleet.

Gleason has also deferred a ruling on a claim by Greenpeace that Shell has failed to state a viable cause for action against the environmental organization.

However, the court has found that it is likely that Greenpeace will take action against Shell's Arctic operations; that those actions would likely cause "irreparable harm" to Shell; that the "balance of the equities" favors Shell; and that an injunction against Greenpeace is in the public interest. On those grounds, Gleason issued the preliminary injunction against Greenpeace while the remaining issues in the court case are dealt with.

—ALAN BAILEY

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OIL PATCH BITS

clean energy solutions to customers worldwide. The target markets include manufacturers and retailers that have committed to utilizing an increasing percentage of their raw materials from renewable sources, as well as municipalities and state governments.

Jacoby Energy Development Inc. is a wholly owned subsidiary of the Jacoby Development Group based in Atlanta, Ga.

Native owned ASRC has declared its spring dividend

As reported by AP Newsfinder March 17, Arctic Slope Regional Corp. said its 11,000 shareholders will receive dividends at $10.38 per share. With the average shareholder owning 100 shares, each will get approximately $1,038. The dividend will be issued April 13.

ASRC President and CEO Rex Rock Sr. said the corporation is pleased to announce a healthy spring dividend despite a challenging business climate.

The total distribution will be about $12 million.

The spring dividend brings the total dividend dollars distributed by the corporation to nearly $543 million.

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PROJECT REVIEWS

Stanway said it is in Canada's best interest to have "a thorough but efficient regulatory regime to assess all large industrial projects" that will create jobs and prosperity.

"If we can get to those decisions more efficiently, it's got to be helpful," said David Collyer, president of the Canadian Association of Petroleum Producers. "It also gives people more clarity, more predictability, more certainty about how the system is going to work."

Asian trade ties sought

Harper has just returned from his second trip in recent months to Asia, seeking to cement trade ties with that region by attracting investment in resource development and export facilities, motivated by U.S. delays in approving Trans Canada's Keystone XL pipeline from Alberta to Texas refineries.

Finance Minister Jim Flaherty, in releasing his 2012-13 budget, said legislation will soon be introduced to achieve the government's goal of "one project, one review."

The changes will affect all major natural resource projects, with the greatest impact on oil sands development and energy pipelines along with hard-rock mining.

"We will implement responsible resource development and smart regulation for economic projects … maintaining the highest standards of environmental protection," Flaherty said.

Threat of regulatory burdens

The budget document noted that regulatory burdens threaten the viability of C$500 billion in announced new investment over the next 10 years by creating "an increasingly complicated web of rules and bureaucratic reviews that have grown over time, adding costs and delays that can deter investors."

"Everyone wants environmental protection, but let's get it done on a timely basis," Flaherty said, arguing Canada could "blow it" unless it puts an end to environmental reviews that have been dragged out over as much as eight years.

He and Natural Resources Minister Joe Oliver have prepared Canadians for a regulatory overhaul in recent months by pointing out delays in regulatory processes that have already lasted eight years for the C$16.2 billion Mackenzie Gas Project and six years for the joint Suncor Energy-Total Joslyn oil sands mine, costing C$6 billion and targeting eventual output of 100,000 bpd.

Oliver has campaigned across Canada against what he described as a "needlessly complex, duplicative regulatory system."

He has estimated the oil sands could generate C$3.3 trillion in economic benefits to Canada over the next 25 years, largely based on forecasts such as the Canadian Energy Research Institute's updated estimate that oil sands production could grow to 5.4 million bpd from 1.6 million bpd by about 2045.

The job-creation spin-off from the oil sands is also a government priority. In a new report, the Petroleum Human Resources Council of Canada forecast that in-situ oil sands operations alone will increase their payrolls to 35,000 by 2021 from 20,000 last year, plus 6,000 to replace those who retire.

Environmental protection

Oliver said the upcoming changes do not mean Ottawa will favor development of natural resources over environmental protection.

"We will ensure that no project goes ahead if it isn't safe for Canadians and safe for the environment," he said.

Government frustration boiled over earlier this year after environmentalists and First Nations made up the bulk of 4,500 groups and individuals who registered to speak at a joint National Energy Board-Canadian Environmental Assessment Agency hearing into Enbridge's proposed Northern Gateway project, underpinning Harper's ambition to open markets for Canadian crude in Asia and threatening to extend the regulatory process to three and a-half years.

The opposition to Northern Gateway is expected to be repeated as Kinder Morgan proceeds with its own scheme to double capacity on the Trans Mountain pipeline to 600,000 bpd, also targeting Asia-Pacific markets.

Across the border funding

What infuriated the government was evidence that U.S. activists were helping finance Canadian charities and whipping up opposition to oil sands development, pipelines to tanker ports on the British Columbia coast and fast-emerging proposals to start LNG exports to Asia.

"Concerns have been raised that some charities may not be respecting the rules regarding political activities," the budget document said.

"There have also been calls for greater public transparency related to the political activities of charities, including the extent to which they may be funded by foreign sources."

For openers, the government said it will be more rigorous in policing the 10 percent limit on political spending by charities.

Limit on reviews

The legislation will impose an overall two year limit on environmental reviews, capping hearings by the National Energy Board at 18 months and standard environmental assessments at one year.

Project oversight will be consolidated into fewer government departments and agencies and C$14 million will be spent over two years to integrated consultations with aboriginal peoples into project reviews.

Analysts at J.P. Morgan said the new rules could "optimistically mean the (Northern Gateway) pipeline being operational by early 2016 or before. Add in the Trans Mountain pipeline and the implication is that Canada could be shipping considerable volumes of oil into the Pacific basin within four years."

They also said accelerating project approvals would free up the supply chain where bottlenecks and limited market access mean that Canadian crude producers are receiving around 25 percent less for their crude than if it were being sold on the international market.

Fisheries Act changes

Canada's Fisheries Minister Keith Ashfield said that the Fisheries Act will also be changed to remove some obstacles facing Northern Gateway, whose planned pipeline route crosses about 1,000 fish-spawning rivers and streams.

"There is ample evidence that the policies we have in place now are infringing on the everyday way of life of Canadians," he said in the House of Commons.

Simon Dyer, policy director at the Pembina Institute, an Alberta-based environmental thank tank, said in statement the longest regulatory delays stem from companies changing their plans or failure by the government to meet its own regulatory obligations.

He said Oliver has been "trying to paint the picture of a problem that doesn't exist."

Shawn Denstedt, an attorney with the firm of Osler, Hoskin & Harcourt, said the regulatory changes are needed to end "perpetual assessments … that don't protect the environment, help the economy or help the social fabric of Canada." ●

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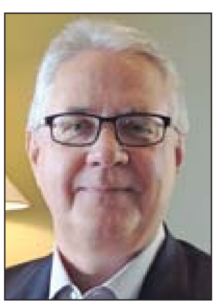
BROOKS RANGE

anomalies on 230,000 acres of leases, is "bigger than us … bigger than both of us," Thompson said, referring to the two companies that control the acreage in the unit — operator Brooks Range Petroleum's parent AVCG and Nabors Industries' Ramshorn Investments.

"We've had much more success than our owners can afford … more than we imagined. … Simply put Mustang along with our other development opportunities and exploration upside across the North Slope is much bigger than we are, so we are looking for a large partner, or partners, to share capital needs," he said.



Ken Thompson, interrupted while viewing Mustang seismic mapping, reservoir simulation grid and projected oil production curve.

AVCG and its partners have spent "about 200 million dollars on exploration in the last 10 years, $40-60 million of that in the last couple of years, and we will now increase spending substantially to develop Mustang, confirm our other development areas and continue to explore," he said.

It's going to take "a few hundred million dollars to develop Mustang," he said; a project that operator Brooks Range would like to see in production in early 2014 from seven horizontal producer wells and eight horizontal injectors, utilizing a standalone modular facility and a pipeline connecting to the Alpine pipeline which crosses near the wells.

"This year we went back in and deepened a well we started last year and got a confirming flow test. Then the second well, Mustang 1, came in with thicker sand and we didn't need to drill another well, as planned. We decided to save our capital for development," Thompson said.

Mustang just part of the story

The other fields AVCG and Ramshorn have in their joint, Brooks Range-operated, North Slope portfolio include "another 100 million barrels in reserves and resources in three other development areas that we have pieced together in the last several years," Thompson said, as well as "numerous strat traps that are in the 10-50 million barrel range which add up to a valuable 'string of pearls'."

The anchor field will be Mustang, which could be larger than 40 million barrels of recoverable oil, as Thompson said there may be a Kuparuk formation extension to the northwest that would add additional reserves and field life, in an area the company calls Appaloosa, where Brooks Range will drill extension exploratory wells in the future.

Plus, there is the Brookian: "When we drilled North Tarn No. 1, we did encounter Brookian sands with oil shows but they were lower permeability than anticipated. Later in field development, we plan to test their commerciality with a long horizontal well and frac jobs ... or recomplete depleted Kuparuk producers into the Brookian sands with horizontals," he said.

Three other development areas, 100 million barrels

The other three development areas that Thompson said hold about 100 million barrels in recoverable reserves and resources "need some delineation drilling before construction of production facilities. …"

"Four years ago Brooks Range had good results from an Ivishak oil flow test at Beechey Point," the unit north of the Prudhoe Bay field, in the Gwydyr Bay region. And we know of other accumulations in what we call the East Bank development area of our Beechey Point unit.

"We also found Kuparuk sands right next to ConocoPhillips' Nanuq field in our Tofkat well, and we mapped seismic anomalies in the Brookian and Jurassic sands," Thompson said.

"Then we acquired leases just east and adjacent to the Badami unit, between it and Point Thomson, called our Telemark development. An oil well drilled in 1970 by one of the majors tested 750 barrels of oil a day in the Flaxman sandstones," he said.

The nine-lease Telemark prospect, which Brooks Range is in the process of unitizing, wasn't commercial at $18 oil, Thompson said, but today, with horizontal wells and higher oil prices, it's a different story.

Up to 1 billion barrels, may be 30-40% producible

As for the smaller traps, as former president of ARCO Alaska, which pioneered 3-D seismic west of the Kuparuk River field, Thompson saw a lot of the 10-50 million barrel traps on seismic a decade or more ago, what he calls a "string of pearls." And more recently with Brooks Range.

"Our joint venture, just in the last two years, has finally been able to analyze all the proprietary 3-D we have run. When we map our stratigraphic anomalies we see up to 1 billion barrels of oil recoverable … so with geologic chance factors, maybe 30-40 percent of that is producible. …

"Bottom line, we have a great portfolio of map-able exploration projects for the next three years, and beyond," Thompson said.

Using Tudor, Pickering, Holt & Co.

Which is why Thompson, the man in charge of raising money for operator Brooks Range, brought in a Houston-based integrated energy investment and advisory firm to help assist in evaluating strategic options for AVCG and Nabors joint portfolio of Alaska North Slope leases.

"We have hired Tudor, Pickering, Holt & Co., the firm that pieced together the Armstrong/Repsol deal, to work on behalf of AVCG and Nabors," Thompson said, with AVCG taking the lead and Nabors-owned Ramshorn also joining the process. Ramshorn and AVCG recently bought out TG World Energy, the third partner in the Brooks Range-operated leases.

"We're looking for a partner that can come in and take a large portion of our working interest in return for funding. We want to move ahead this fall with the Mustang development. And next winter move on delineation of the other three development areas and continue a good level of exploration particularly on our western anomalies," Thompson said.

They are open to an acquisition of the full or partial ownership of the assets or an equity investment into the holding company, AVCG, he said.

But Brooks Range's preference is for a cash-based bonus component up front with a commitment to fund the forward program.

Alaska-grown oil company might go public

Tudor, Pickering is pursuing two funding strategies.

"We recently shared all of our data with five world-class private equity firms — in the energy industry they are the top five you'd want to have involved," Thompson said.

"In strategy 1 they would invest all the capital for development and exploration until we get to first quarter 2014 when Mustang starts production. Once that happens we'll have enough operating cash flow

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APACHE WELLS

Aurora drilled the Aspen No. 1 wildcat to 4,485 feet in mid-2005, but did not find commercial quantities of natural gas. The company re-entered the well in mid-2008.

Aurora operates the nearby Lone Creek and Moquawkie units.

Humble drilled the Tyonek Reserve No. 1 to around 13,600 feet in 1965. Simasko drilled the Simpco East Moquawkie No. 1 in 1979 to a total depth of 10,852 feet.

Although it isn't discounting the possibility of associated gas discoveries, Apache is looking to develop oil deposits overlooked when Cook Inlet exploration moved north.

In the fall or winter, Apache plans to move across the Inlet to drill the Captain Boomer well along the shoreline some four miles southwest of Moose Point. The well would be about a quarter mile inland, but still outside of the Kenai National Wildlife Refuge.

The proposed location is north of the Birch Hill unit and northeast of the Moose Point Unit No. 1 well that Amarex Inc. drilled to a total depth of 10,058 feet in early 1978.

Captain Boomer would be within spitting distance of a Tesoro multiproducts pipeline.

Alongside offshore leases

Those two proposed well locations in effect bookend the northern section of the offshore Kitchen Lights unit where Furie Operating Alaska LLC is currently drilling and the southern section of the North Cook Inlet unit, a legacy field operated by ConocoPhillips.

Apache holds a fairway of offshore leases just east of those existing units. When the company picked up the leases in early 2011, the state speculated that the company might be targeting smaller structures hidden between the major structures in the region.

"There's a lot of playing room between the big, big structures," Robert Swenson, director of Alaska's Division of Geological and Geophysical Surveys, said at the time.

Toward the end of last year, Apache kicked off a three-year 1,200-square mile 3-D seismic shoot across its entire leasehold in Cook Inlet using a new nodal technology.

With more than 800,000 acres, Apache is the largest leaseholder in Cook Inlet. Its portfolio covers the entire the basin, from the southern Kenai Peninsula to the mouth of the Susitna River and including the east and west sides, as well as offshore leases.

Apache recently submitted an oil discharge prevention and contingency plan to the Alaska Department of Environmental Conservation. The plan is meant to cover the entire multiyear program, but Apache is only detailing drilling plans for the first year.

Editor's note: A copyrighted oil and gas lease map from Mapmakers Alaska was a research tool used in preparing this story.

—ERIC LIDJI

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MAC LINE FUNDING

project: "ConocoPhillips has been involved with three other energy companies, as members of the Mackenzie Gas Project, on the development of the Mackenzie Valley Pipeline and gathering system, which was proposed to transport onshore gas production from the Mackenzie Delta in northern Canada to established markets in North America. The company has a 75 percent interest in the Parsons Lake natural gas field, one of the primary fields in the Mackenzie Delta, which would have anchored the pipeline development. In the first quarter of 2012, the co-venturers elected to suspend funding of the project due to a continued decline in market conditions and the lack of acceptable commercial terms. The company expects to record a noncash impairment for the carrying value of the undeveloped leasehold and capitalized project development costs of approximately $525 million after-tax, during the first quarter of 2012."

Parsons Lake is one of three anchor fields for the project.

Davy Kong, ConocoPhillips' upstream communications advisor, told Petroleum News April 5 that the "write-down of these assets does not mean they are no longer an important part of our portfolio or that they can't be developed in the future."

The partners in the Mackenzie Gas Project are Imperial 34.4 percent, Aboriginal Pipeline Group 33.3 percent, ConocoPhillips 15.7 percent, Shell 11.4 percent, and ExxonMobil Canada 5.2 percent. Imperial is largely owned by ExxonMobil.

Shell put its share up for sale last year, but has yet to announce a buyer.

—KAY CASHMAN

See full story from Gary Park in next week's issue.

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BROOKS RANGE

from oil production to fund everything else," he said.

Then, "two or three years after that we'd go public, do an initial public offering, a stock market launch," he said.

An IPO can be used to raise expansion capital and become a publicly traded enterprise.

"This interests us — and is viewed as innovative and distinct to some of the equity firms we're talking to — because it would create an Alaska-grown, publicly traded, independent producer. It would be a first for the state," Thompson said.

"But cash from private equity firms can be expensive, dependent on the share of the company they demand for the capital, so pursuing a second strategy makes business sense," he said.

Strategy 2 is to find a producer, or two, in Alaska or elsewhere in the world, who is willing to put up the funds in return for a majority share of the working interests.

"We would like to continue to operate but some company might want to operate; we're open to that discussion. And at the right indicative offer, we would enter into an exclusive arrangement with just one company to own part of or all the assets" Thompson said.

Of the three producers that have requested more detailed data or visited the data room Tudor, Pickering set up two months ago in Houston, and the five oil companies that recently requested to see Brooks Range's drilling results from this winter's drilling, most seem to want Brooks Range to operate.

"We've shared everything" with prospective partners, Thompson said, "from seismic, to lease and financial information, to logs from drilling. We've even run sophisticated reservoir simulations for Mustang and Tofkat development."

Because of confidentiality agreements with the eight prospective producer partners, Thompson could not name them but, he said, they include "producing companies from all over the world; most have never been to the North Slope, but they are interested in Alaska, and some are there already."

Besides being able to handle the funding of the Mustang development, "we're looking for a partner whose culture fits our culture and is great to work with. Again, however, for the right price, we would divest all assets and turn over operations if required," he said.

What about ACES?

What about Alaska's production tax, Alaska's Clear and Equitable Share, the production tax enacted in 2007, better known by its acronym, ACES? Are prospective producers paying attention to the debate in Juneau?

"Yes," Thompson said, "they are watching. Some are even tapping into the Legislature's website, watching committee hearings on the tax bills."

"In the last two months, in dealing with planning groups and senior executives in these companies, they have all asked, 'what is Alaska going to do on the tax regime?' I have been honest with them; I tell them that I don't think it will get worse, that there will probably be a modest improvement," he said.

"Some of these companies are going to wait on the adjournment of the legislative session. It will effect what they are going to do."

"This deal, finding a funding partner, or partners, can be a big step in helping level out North Slope production, so that more companies get interested in Alaska," Thompson said.

Shale player's main interest tight oil

One company that is looking at operator Brooks Range and all the leases it operates for the joint venture between AVCG and Nabors has told Thompson that "they find our conventional plays interesting but their main interest is our acreage that also has potential for unconventional source rock plays, the Shublik and other shales."

"We own a little over 230,000 acres on the North Slope; 100,000 acres of that is out west, between Kuparuk and Alpine, right in the fairway with the right maturity for oil in the source rock shales. One company is evaluating that acreage for unconventional oil. They say our conventional plays lower their risk in the shales," he said.

So what does Thompson, a petroleum engineer turned top executive for ARCO, turned independent player, think of his last few years, and future, with AVCG and Brooks Range?

"I have had so much fun; this last winter, especially. It's like the old days for me. … The last time I was this excited was in 1994-95, when I first came to Alaska, and the well-site geologist faxed to my home the discovery confirmation well logs for the Alpine field," he said. ●

Editor's note: Part two will feature the history of Alaska Venture Capital Group, or AVCG, which officially got its start in 1999; the formation of Brooks Range Petroleum Corp. as an Alaska-based operating company; and more information on the joint venture's 100,000-acre leasehold that has good potential for tight oil production from northern Alaska's source rocks, which are primarily shale. It will also have more information about Brooks Range's team and Ken Thompson's vision for the state of Alaska and the infrastructure needed for unconventional oil production, such as roads, which he refers to as, "Build it, and they will come."

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