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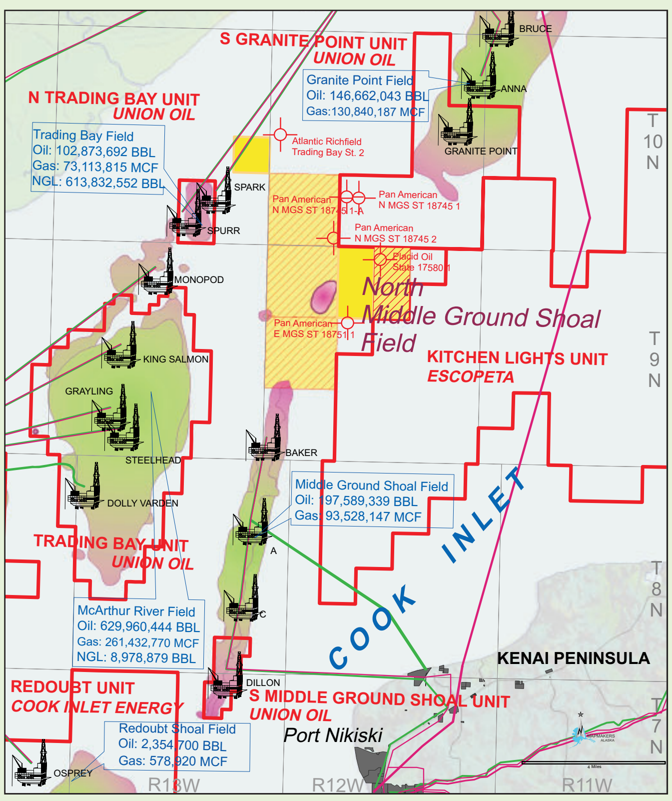
page 4 ConocoPhillips earns $381 million in Alaska in 2nd quarter of year

Buccaneer going for units



Buccaneer Alaska LLC has applied to form two units in Cook Inlet. One, shown in the map above, is adjacent to Escopeta's Kitchen Lights unit. See story page 10.

Aurora Gas back on track with Nicolai Creek gas storage project

With government approvals moving ahead for Aurora Gas' planned new storage facility in its Nicolai Creek gas field on the west side of Alaska's Cook Inlet and with the passage earlier this year of state legislation designed to encourage the development of new natural gas storage facilities in the Cook Inlet basin, Aurora's plans for storage at Nicolai Creek have regained momentum, Aurora Gas President Scott Pfoff told Petroleum News July 21.

JUDY PATRICK

SCOTT PFOFF

"We're back interested in pursuing this project," Pfoff said.

Pfoff said that negotiations with the Alaska Department of Natural Resources over the terms of a storage lease are now progressing well and that Aurora has a

see **AURORA GAS** *page 20*

Drilling comes next; Ormat files plan for Mount Spurr bore holes

Just a few weeks after filing a plan for summer aerial surveys and fieldwork on the southern flanks of Mount Spurr, an active volcano on the western side of Alaska's Cook Inlet, Reno-based Ormat Nevada has filed another plan, this time for drilling some small-diameter core holes as part of the company's search for a viable geothermal power source for the Southcentral Alaska electricity grid.

Ormat says that it hopes to drill four holes in September using a lightweight drilling rig carried to drill sites by helicopter. Two of the sites are in the eastern part of the exploration area, with the other two sites in the central part of the area.

Geothermal exploration often includes the drilling of small diameter holes to determine subsurface temperature gradients and to determine the nature of the subsurface rocks,

see **SPURR GEOTHERMAL** *page 19*

FINANCE & ECONOMY

Sale chatter resumes

Alaska assets often mentioned as BP replaces Hayward, ups divestiture target

By WESLEY LOY
For Petroleum News

Speculation has blazed up again, perhaps with greater intensity than ever, that BP will sell part or all of its ownership stake in Prudhoe Bay and perhaps other oil fields on Alaska's North Slope.

© BP P.L.C

BOB DUDLEY

BP stoked the conjecture when it announced July 27 that it will divest assets worth up to $30 billion over the next 18 months. That's triple the amount the company previously said it would spin off to help meet huge expenses associated with the catastrophic Gulf of Mexico rig explosion and oil spill.

BP also announced that its scorned chief executive, Tony Hayward, would step down effective Oct. 1 and that an American, Bob Dudley, would replace him.

The New York-born, Mississippi-raised Dudley, 54, joined BP from Amoco after the two companies merged in 1998. He's been leading BP's cleanup and compensation programs in the Gulf, and from 2003 until late 2008, he headed BP's Russian joint venture, TNK-BP.

"Today is a very sad day for me," Hayward said in a July 27 news conference. "As many of you are well aware, I have spent my entire professional career at BP. I love the company and everything it stands for. I've thought long and hard over the last

see **SALE CHATTER** *page 18*

NATURAL GAS

CINGSA applies to RCA

Semco forms joint venture with MidAmerican to develop Kenai gas storage facility

By ALAN BAILEY
Petroleum News

With gas utility Enstar Natural Gas Co. wanting to be able to use a planned new gas storage facility on Alaska's Kenai Peninsula by the summer of 2012, to avert Southcentral Alaska gas deliverability shortfalls during the following winter, the race is on to fast track the Kenai gas storage development.

In a recent flurry of activity, Semco Energy, Enstar's parent company, and MidAmerican Energy Holdings Co. announced July 28 that they have formed a joint venture to develop the facility and that the joint venture has filed for a certificate with the Regulatory Commission of Alaska. And

> *"This facility represents a significant commitment by Semco and MidAmerican. For Semco, this investment nearly doubles the size of our business in Alaska."*
> **—Semco CEO and President George Schreiber**

on July 26 the Alaska Department of Natural Resources issued a notice requesting public comments on its proposal to issue a gas storage lease, a land surface lease, a pipeline easement and land classification orders for the facility.

Semco has said that RCA approval of the project is needed by December, before construction of

see **CINGSA** *page 19*

NATURAL GAS

Gas foundation crumbling

Reduced western Canada volumes on TransCanada's Mainline force higher rates

By GARY PARK
For Petroleum News

A milestone in the history of Canada's natural gas industry is turning into a millstone.

TransCanada's Mainline from Alberta to the big population centers in Eastern Canada, with extensions into the United States, has been a profit and job generator for the gas sector of the Western Canada Sedimentary basin for more than 65 years.

Those days could be winding down, reinforcing the grim messages over recent years from TransCanada and organizations such as the Canadian Energy Research Institute.

It's a simple problem. Conventional gas supplies from the WCSB — hammered by high costs and low commodity prices — are in a decline from which no one can see an end.

> *The Mainline capacity of 3.5 billion cubic feet per day to the system's northern zone over Ontario has tumbled to as low as 500 million cubic feet per day.*

The Mainline capacity of 3.5 billion cubic feet per day to the system's northern zone over Ontario has tumbled to as low as 500 million cubic feet per day. In 2009, contracted long-haul volumes dropped to half what they were in 2006.

Rate changes over the past two or three years are estimated to have increased by as much as C50 cents per gigajoule.

see **GAS FOUNDATION** *page 20*

contents

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Alaska - Mackenzie Rig Report

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status

Alaska Rig Status

North Slope - Onshore

Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay W-19BL1	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Stacked Doyon Yard	Available
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay S-100	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4-23	ConocoPhillips
OIME 2000	141 (SCR/TD)	Prudhoe Bay C-28B	BP
TSM 7000	Arctic Wolf #2	Stacked at Prudhoe Bay	FEX/Available
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 1R-06A	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay, Stacked out	BP
Mid-Continental U36A	3-S	Stacked, Milne Point	BP
Oilwell 700 E	4-ES (SCR)	Milne Point MPU F-50	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay Rig Maintenance	BP
Dreco 1000 UE	9-ES (SCR/TD)	Rig Stacked	Available
Oilwell 2000 Hercules	14-E (SCR)	Kuparuk 2A-27	ConocoPhillips
Oilwell 2000 Hercules	16-E (SCR/TD)	Stacked at Prudhoe Bay Unit West Pad	Brooks Range Petroleum
Oilwell 2000	17-E (SCR/TD)	Stacked, Point McIntyre	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Point Thompson PTU-15	ExxonMobil
Academy AC electric Canrig	105-E (SCR/TD)	Stacked at Deadhorse	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Kuparuk OP04-07	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site F-47B	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site 2-36	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2A-14	ConocoPhillips

North Slope - Offshore

BP (rig built & being assembled by Parker)			
Top drive, supersized	Liberty rig	Endicott SDI for Liberty oil field	BP
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-16	Pioneer Natural Resources
Oilwell 2000	33-E	Northstar, Stacked out	BP
OIME 2000	245-E	Kuparuk OP12-01	ENI

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Rigging up for Moquawkie 4 for a workover	Aurora Gas
Doyon Drilling			
TSM 7000	Arctic Fox #1	Stacked	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Still on maintenance	Marathon Oil
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai SLU 41-33RD	Chevron
Rowan Companies			
AC Electric	68AC (SCR/TD)	Stacked Kenai, Cosmopolitan	Pioneer Natural Resources

Cook Inlet Basin – Offshore

Chevron (Nabors Alaska Drilling labor contract)			
	428	M-29 Steelhead platform	Chevron
XTO Energy			
National 1320	A	Coil tubing cleanout planned off Platform A in the near future	XTO
National 110	C (TD)	Idle	XTO
Kuukpik	5	Stacked in Kenai	Available

Mackenzie Rig Status

Canadian Beaufort Sea

SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Racked in Norman Wells, NT	Available

The Alaska - Mackenzie Rig Report as of July 29, 2010. Active drilling companies only listed.

TD = rigs equipped with top drive units WO = workover operations
CT = coiled tubing operation SCR = electric rig

This rig report was prepared by Marti Reeve


JUDY PATRICK

Baker Hughes North America rotary rig counts*

	July 23	July 16	Year Ago
US	1,585	1,571	943
Canada	349	365	180
Gulf	14	12	36

Highest/Lowest		
US/Highest	4530	December 1981
US/Lowest	488	April 1999
Canada/Highest	558	January 2000
Canada/Lowest	29	April 1992

*Issued by Baker Hughes since 1944

PIPELINES & DOWNSTREAM

Tentative Cook Inlet tariff deal reached

The conflict over a Cook Inlet pipeline operator's steep tariff hike might soon be over.

Lawyers for Cook Inlet Pipe Line Co. and oil producer Cook Inlet Energy on July 26 jointly filed a notice with the Regulatory Commission of Alaska that the two sides have reached an "agreement in principle."

They said they aim to file a formal settlement agreement by Aug. 31.

Cook Inlet Energy objected after CIPL raised its rate by 259 percent, from $4.06 to $14.57 per barrel.

The RCA allowed the rate to take effect at the outset of 2010, but only temporarily and subject to refunds.

Texas-based CIPL operates a 20-inch pipeline that runs 42 miles from Granite Point down the western side of Cook Inlet to the Drift River Oil Terminal. The pipeline was installed in 1966.

CIPL has attributed much of its tariff increase to damage the erupting Redoubt volcano caused in 2009, idling west Cook Inlet oil production and the pipeline for months.

Cook Inlet Energy, in its formal complaint filed with the RCA in January, argued the rate hike was excessive and "could not have come at a worse time" for the fledgling company, which in late 2009 bought oil and gas assets on the west side of the Inlet.

In their July 26 joint filing, CIPL and Cook Inlet Energy said Daniel K. Donkel, an overriding royalty interest owner who also objected to the rate increase, had reviewed the agreement in principle and "supports its terms."

The companies asked that the case before the RCA be "held in abeyance" while they hammer out the formal settlement agreement.

Petroleum News asked David Hall, chief executive for Cook Inlet Energy, whether the parties have agreed to a new rate. Hall said he couldn't divulge details.

"But I would say it looks good," he said.

—WESLEY LOY

ADDRESS
P.O. Box 231647
Anchorage, AK 99523-1647

NEWS
907.522.9469
publisher@petroleumnews.com

CIRCULATION
907.522.9469
circulation@petroleumnews.com

ADVERTISING
Susan Crane • 907.770.5592
scrane@petroleumnews.com

Bonnie Yonker • 425.483.9705
byonker@petroleumnews.com

FAX FOR ALL DEPARTMENTS
907.522.9583

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● FINANCE & ECONOMY

ConocoPhillips Alaska 2Q profits down 26%

Oil, gas production continue to fall while commodity prices hold steady; company reports $381M 2nd quarter Alaska earnings

By ERIC LIDJI
For Petroleum News

ConocoPhillips earned $381 million in Alaska in the second quarter of the year, down 26 percent from the first quarter and nearly 6 percent from the second quarter of 2009.

Despite those declines, rising oil prices year over year are lifting profits. Over the first six months of the year, ConocoPhillips has earned $898 million in Alaska, up nearly 28 percent from $648 million it earned through the first half of 2009. ConocoPhillips' exploration and production activities continue to be more profitable in Alaska than across the Lower 48, where the company earned $155 million, down from $240 million in the first quarter, but up from a loss of $68 million in the second quarter of 2009.

JIM MULVA

Companywide, ConocoPhillips earned $4.16 billion in profits on $50 billion in revenues, up from $2.1 billion earned in the first quarter on $45.7 billion in revenues.

ConocoPhillips is the largest oil and gas producer in Alaska by volume, and the only major oil company to break out Alaska earnings figures on a quarterly basis.

The filings are the first since the explosion of the Deepwater Horizon drilling rig caused an oil spill in the Gulf of Mexico, prompting the federal government to issue a moratorium on offshore drilling that is impacting Alaska projects, such as ConocoPhillips' assets in the Chukchi Sea.

"There has been heightened public focus on the safety of the oil and gas industry during this past quarter, and we are committed to improve our ability to respond immediately to offshore incidents," Jim Mulva, ConocoPhillips' chairman and chief executive officer, said in the company's earnings release. "Safety and environmental stewardship, including the operating integrity of our assets, remain our highest priorities."

Production down, prices even

Production typically falls in Alaska in the second quarter.

ConocoPhillips produced 221,000 barrels of liquids per day, down from 247,000 bpd in the first quarter and 252,000 bpd in the second quarter of 2009. Natural gas production fell to 82 million cubic feet per day, down from 94 mmcfpd in the first quarter, but roughly level with the 83 mmcfpd the company produced in the second quarter of 2009.

ConocoPhillips reported an average LNG sales price of $12.08 per mcf, perhaps the highest nominal price ever recorded by the company.

In the Lower 48, ConocoPhillips produced 161,000 barrels of liquids per day, up 3 percent from the first quarter, but down 5 percent from the second quarter of 2009. The company produced 1.7 billion cubic feet of gas in the Lower 48 during the quarter.

Oil prices increased only 19 cents quarter over quarter to $77.44 per barrel, but jumped substantially year over year from the $55.25 ConocoPhillips reported in the second quarter of 2009. Natural gas prices fell to $4.73 per thousand cubic feet, from $5.28 per mcf reported in the first quarter and $6.38 per mcf in the second quarter of 2009.

Those prices show Alaska oil and gas trading at a premium to the Lower 48, where ConocoPhillips reported oil prices of $55.70 per barrel and gas prices of $3.93 per mcf.

LNG prices keep rising

ConocoPhillips' liquefied natural gas sales from the Kenai Peninsula export terminal averaged 51 mmcfpd, down from 56 mmcfpd in the first quarter, but up from 47 mmcfpd in the second quarter of 2009. ConocoPhillips and co-owner Marathon Oil are currently seeking a two-year extension of their export license from the U.S. Department of Energy.

ConocoPhillips reported an average LNG sales price of $12.08 per mcf, perhaps the highest nominal price ever recorded by the company. ConocoPhillips sold Kenai LNG for $11.70 per mcf in the first quarter and $7.20 per mcf in the second quarter of 2009.

ConocoPhillips also reported $10 million in "exploration charges," up from the $7 million spent in the first quarter and the $8 million spent in the second quarter of 2009. ●

Contact Eric Lidji at ericlidji@mac.com

● PIPELINES & DOWNSTREAM

Alberta battles headwinds

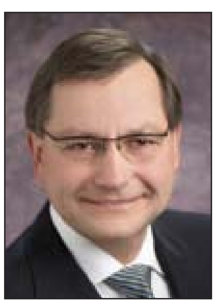
EPA pressures Obama administration to demand more GHG data on planned Keystone addition; industry says EPA estimates outdated

By GARY PARK
For Petroleum News

Alberta Premier Ed Stelmach thinks he's making progress in persuading U.S. lawmakers that the oil sands industry is cleaning up its act.

But, apparently, not everyone in Washington is buying that message.

The Environmental Protection Agency, which regulates U.S. environmental laws, has urged the Obama administration to stall progress on a US$12 billion expansion of TransCanada's Keystone pipeline until more complete information is available about the carbon footprint created by the oil sands.


ED STELMACH

The EPA recommended in a letter signed by assistant administrator Cynthia Giles that the "discussions of (greenhouse gas) emissions be expanded to include … an estimate of the extraction-related (greenhouse gas) emissions associated with the long-term importation of oil sands crude."

She estimated that emissions from the oil sands are about 82 percent greater than the average crude refined in the U.S., on a well-to-fuel-tank basis.

"Alongside the national security benefits of importing crude oil from a stable trading partner, we believe the national security implications of expanding the nation's long-term commitment to a relatively high carbon source of oil should also be considered," Giles wrote.

She calculated that the additional pollution from oil sands development would be equivalent to 27 million metric tons of carbon dioxide equivalent per year, matching the output from seven coal-fired power plants.

Giles also argued that additions to the existing Keystone pipeline, with the eventual goal of delivering oil sands crude to Gulf Coast refineries, would promote more growth of the oil sands industry.

"Based on our review, there is a reasonably close causal relationship between issuing a cross-border permit for the Keystone XL project and increased extraction of oil sands crude in Canada intended to supply that pipeline," Giles said.

"Not only will this pipeline transport large volumes of oil sands crude for at least 50 years from a known, dedicated source in Canada to refineries in the Gulf Coast, there are no significant current export markets for this crude oil other than the U.S. Accordingly, it is reasonable to conclude that extraction will likely increase if the pipeline is constructed."

Giles' letter challenged TransCanada's assessment of long-term energy needs, suggesting the company had overlooked the potential development of clean energy technologies and measures that might be taken to reduce future dependence on oil.

CAPP: EPA estimates based on 2005 data

Travis Davies, a spokesman for the Canadian Association of Petroleum Producers, told reporters the EPA estimates of emissions were based on 2005 data, since when the industry has made constant gains in shrinking its environmental footprint.

He said the most recent studies indicate the overall cycle of GHG emissions of fuel from the oil sands are only 5 to 15 percent higher than conventional crude.

The EPA letter follows comments by Henry Waxman, a Democratic congressman who chairs an energy and commerce committee in Washington, who told Secretary of State Hillary Clinton that the Keystone pipeline would be a "step in the wrong direction" by increasing U.S. reliance on the "dirtiest source of transportation fuel."

A spokesman for Stelmach said the EPA submission is only one step in the regulatory process facing the Keystone application.

"Our position is that the best available information should be a key component of any jurisdiction's consideration of projects of this nature," he said.

Echoing the negative views of the oil sands among U.S. lawmakers and officials, David Jacobson, the U.S. Ambassador to Canada, told the Pacific NorthWest Economic Region conference in Calgary on July 19, that "more needs to be done" by the oil sands industry to "demonstrate how they're meeting the challenges of providing energy security while meeting their obligations of environmental stewardship."

see **HEADWINDS** page 7

Unloved, but not forsaken

The economics of upgrading heavy oil into synthetic crude for further refining are expected to remain marginal for many years say executives of companies that are active in the field in Alberta.

But there is no shortage of project backers in Canada.

Speaking to a TD Newcrest unconventional oil conference in Calgary in July, Terry Jocksch, senior vice president at Canadian Natural Resources — which bought a 50 percent share in May of North West Upgrading's plan to refine oil sands production — said the outlook for upgrading is not good.

He said Canadian Natural concluded from an internal study done several years ago that upgrading its heavy oil, based on the price-differentials between heavy and light crudes, represented shaky economics.

But Canadian Natural does include upgrading in its overall strategy, which is why it chose to form a joint venture with North West in hopes of receiving bitumen feedstock under a royalty-in-kind initiative being promoted by the Alberta government.

"We are a very balanced company … so we look at blending, pipeline capacity and obviously upgrading capacity as well," Jocksch said.

Robert Peabody, chief operating officer for Husky Energy — which traded 50 percent of the proposed 200,000 barrels per day of production from its Sunrise oil sands project for an equal share of a BP refinery in Ohio that is being reconfigured to process bitumen — said his company has learned over 60 years that price differentials fluctuate widely.

"But, for a robust business, given the total amount of capital you're investing in this value chain, it's not a bad idea to participate throughout the chain," he said.

Cyclical business

Total E&P Canada President Jean-Michel Gires said his Paris-based company is still committed to a 150,000 bpd upgrader in the Edmonton area.

"Just five years ago, everybody wanted to build new upgraders and dedicated upgraders and now it looks like nobody wants to build one, so it's technically very cyclical," he said.

Gires said Total believes the best long-term strategy is to have some level of

see **HEAVY OIL** page 7

● EXPLORATION & PRODUCTION

Conoco keeps the oil flowing at Alpine

New drilling around periphery of the field opens up new production possibilities, while development of the satellites also continues

By ALAN BAILEY
Petroleum News

As with any oil field, the focus at the Alpine field and its satellites in the Colville River unit on Alaska's North Slope is on maximizing field value by slowing as much as possible the inevitable production decline that follows peak field production.

And the most recent progress report that unit operator ConocoPhillips has filed with the Alaska Department of Natural Resources describes the steps that the company is taking to keep as much as oil as possible flowing from Alpine and its satellites for export through the trans-Alaska oil pipeline, while also looking for new oil development opportunities within and near the unit boundary — Alpine, one of the success stories of modern North Slope exploration, has become a stepping out point for developing new, modest sized oil accumulations at the western side of the central North Slope and west into the National Petroleum Reserve-Alaska.

Started 2000

The Alpine field, owned 78 percent by ConocoPhillips and 22 percent by Anadarko Petroleum Corp., first went into operation in 2000, producing light crude oil from two relatively fine-grained Jurassic sand horizons, termed the A sands and C sands, in what geologists refer to as the Beaufortian sequence of rocks. The development strategy involved the use of horizontal wells that would run through the sands, with some wells producing the oil and other wells injecting water to shift the oil through the reservoir rocks. Development drilling was done from two gravel pads: the CD1 pad, holding the field processing facilities, and the CD2 pad some three miles to the west.

And in the years after the Alpine startup three smaller satellite fields — Fiord, Nanuq and Qannik — have all gone into production within the Colville River unit, all using the same general development strategy of interwoven horizontal production and injector wells, and all producing oil through the Alpine field production facilities.

Fiord, the first of the satellite fields, went into production in August 2006 from two connected reservoir zones, one in the Nechelik sand of the Jurassic Kingak formation and the other in the Cretaceous Kuparuk C sand. The field was developed from a new gravel pad, the CD3 pad, about five miles north of CD1.

Nanuq came on line in November 2006 using wells drilled from the CD4 gravel pad, about four miles south of CD1. This satellite field produces oil from two horizons: the Kuparuk C sands, equivalent to those at Fiord, and the shallower and younger Nanuq sands, equivalent to the reservoirs of the Meltwater and Tarn satellite fields of the Kuparuk field to the east, and lying in a rock sequence that geologists refer to as the Brookian.

Qannik, which came online in July 2008, uses wells drilled from the extended CD2 pad. The Qannik oil pool lies in a sandstone unit above the Alpine, Nanuq and Fiord reservoirs.

ConocoPhillips next planned step-out from Alpine, the CD5 or Alpine West development, lies in the extreme east of the National Petroleum Reserve-Alaska. This development has been stymied by a refusal by the U.S. Army Corps of Engineers to allow the construction of a bridge across the Nigliq Channel of the Colville River. Development at CD5 could lead to further step-outs to the west, to tackle some known, modest-sized oil accumulations in the NPR-A Moose's Tooth unit.

Continuing development

While work progressed on developing the Alpine satellite fields, development of the central Alpine field continued, with ConocoPhillips completing all of the originally planned field wells by 2005.

The company has implemented an oil recovery method known as miscible water alternating gas, or MWAG, at the field, the progress report says. MWAG involves the mixing of natural gas liquids with natural gas from the field, and injecting the resultant "miscible injectant" in alternation with water. The water consists of both water produced from the field and seawater imported from the Kuparuk field seawater system.

And, following an increasing demand for injected water in both Alpine and its satellites, ConocoPhillips increased the Alpine water pumping capacity in 2009, the report says.

Monitoring of well pressures at Alpine has revealed unexpected pressure declines resulting from mineral scaling in the wells. In 2009 ConocoPhillips initiated a scale inhibitor program in the field and also began fracture stimulating some wells, the report says.

More drilling

Development since 2005 has involved new drilling around the periphery of the field, with two wells drilled into the A sands from CD4 in 2006, three A-sand wells completed from CD2 and CD4 in 2007, and an A-sand well drilled from CD2 in 2008.

ConocoPhillips completed eight additional wells on the edge of the Alpine field in 2009, the report says. Those well were drilled from CD1, CD2 and CD4 to extend the field to the northwest, west and southwest. A CD4 well has also encountered C sand of better quality than expected in the southern part of the field, indicating further development potential there.

In 2010 ConocoPhillips plans to drill a well slanting out east from CD1, to test the C sands in that area, the report says.

And the company planned to conduct a new 3-D seismic survey across the Alpine field in 2010, to help identify new drilling opportunities, as well as to gain insights into fluid behavior and pressure changes in the field.

To date, ConocoPhillips has drilled 117 wells in the Alpine field — 58 injector wells, 57 production wells and two waste disposal wells, the report says. In 2009 oil production averaged 58,900 barrels per day.

Satellite development

And development has continued in the Alpine satellites.

The report says that the initial phase of development of Fiord is now finished, with all surface facilities completed and 11 horizontal wells drilled, and with production supported by MWAG techniques. A new injector and a new producer well in the Fiord Kuparuk zone were completed in 2009 and ConocoPhillips plans five further wells for 2010. The company anticipates drilling sidetrack wells from two existing wells in the winter of 2010, the report says. The average production rate in 2009 was 7,300 barrels of oil per day.

Nanuq has been a good news, bad news story, with the Nanuq Kuparuk reservoir exceeding performance expectations while the shallower Nanuq reservoir has proved disappointing. Average 2009 production from the Kuparuk sands came in at 16,700 barrels per day, while the Nanuq produced just 500 barrels per day. Production from both reservoirs involves MWAG techniques.

ConocoPhillips had suspended new drilling into the Nanuq reservoir pending an investigation into reservoir performance but plans to finish a new horizontal production well in 2010 — the current plan

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● NATURAL GAS

US a friend in need

NWT sees efforts to replace coal, oil with gas as positive for Mackenzie; minister hopes shale gas will stabilize commodity prices

By GARY PARK
For Petroleum News

A mounting campaign among United States lawmakers to legislate use of natural gas rather than coal and oil to generate electricity holds hope for the Mackenzie Gas Project, said Northwest Territories Industry Minister Bob McLeod.

Based on a series of meetings with decision-makers in Washington, D.C., he told Canadian Press "everyone agrees all forms of energy will continue to be required and demand for energy in North America is going to continue to grow."

The possible use of tax incentives in the United States to increase gas consumption for transportation "makes a lot of sense" in the campaign to introduce cleaner-burning fuels, McLeod said.

He suggested the United States will need all the gas it can get if it embraces wider use of the resource and regardless of the sudden emergence of shale gas.

McLeod said some observers and analysts have raised questions about the need for the MGP given the potential of shale gas.

"What we're finding is that amounts of shale gas will be beneficial for natural gas because the prices will be more reliable and predictable," he said.

"In the past utility companies have tended to (rely on coal-fired power) because of the volatility in natural gas prices."

McLeod said the NWT also enforces the use of natural gas because it emits far less carbon dioxide than coal- and oil-based energy.

Inuvik Petroleum Show

Despite the hiatus in Canadian Arctic exploration, pending a regulatory verdict and corporate decision on the MGP, the annual Inuvik Petroleum Show marked its 10th anniversary in June with about 400 delegates and 100 booths.

Larry Peckford, an event organizer, told the CBC the response was better than anticipated in the midst of a slow exploration year, but a decision to shift the focus from the MGP to offshore exploration in the Beaufort Sea was blindsided by BP's blowout in the Gulf of Mexico.

While reluctant to "gain from someone else's misfortune," Bob Reid, president of the Aboriginal Pipeline Group — a potential one-third equity holder in the MGP — said BP's Macondo incident could provide a lift for natural gas.

"If a gas line leaks, it basically dissipates into the air," he said. "It doesn't pollute the ground and you won't find any ducks or geese coated with natural gas."

Reid also told the delegates that a pipeline for the MGP would be an onshore project, posing a different set of risks than offshore drilling.

Business concern about delays

McLeod said a lot of NWT businesses are taking a grim view of the continued delays in the MGP and have a "lot of questions about whether they'll survive much longer if there's no … pipeline."

APG Chairman Fred Carmichael took the high road, arguing the project is "nowhere near dead. Come September (when the National Energy Board is scheduled to issue its final verdict on the MGP application) I think you'll see the sparks fly again."

Doug Matthews, a Calgary-based oil and gas analyst, said that the time being taken by the NEB "is not necessarily a bad thing" except for businesses that had been hoping Beaufort exploration work would fill some of the void caused by the slowdown in MGP-related activity.

Brian Love, manager of the Yukon government's oil and gas branch, said his government and Imperial Oil, lead partner in the MGP, have reached an agreement to manage the impact of MGP pipeline construction if the Dempster Highway to Inuvik becomes the major trucking route for materials.

He also said he hopes the NEB will require the MGP consortium to build a spur line into the northern Yukon if viable natural gas discoveries are made in that region. ●

Contact Gary Park through publisher@petroleumnews.com

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HEAVY OIL

integration.

"We cannot expect to produce 250,000 bpd (from the oil sands) by 2020 and just put that on the market," he said. "We definitely are planning some level of upgrading in Alberta."

Suncor Energy Chief Financial Officer Bart Demosky said the oil sands giant runs two upgraders in northern Alberta capable of handling 225,000 bpd and has an option to proceed "very quickly" on a third.

Brian Ferguson, chief executive officer of Cenovus Energy, predicted tight price differentials will prevail over the next four or five years, despite falling supplies from Mexico, Venezuela and OPEC countries.

Columba Yeung, chief executive officer of Value Creation, which has plans for an upgrader near Edmonton, insisted upgraders must be built for the long term.

Because pipelines are in place to move heavy crudes to U.S. refineries, "people feel that maybe upgraders are not necessary," but when that capacity has been used up, the price gap will widen, he said.

—GARY PARK

Contact Gary Park through publisher@petroleumnews.com

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HEADWINDS

Industry leaders need to do more to exceed government mandates to reduce the carbon footprint, he said.

Stelmach: 'open dialogue'

Stelmach, following a series of recent meetings with governors and senators, told PNWER that U.S. lawmakers are eagerly soaking up as much information as they can about efforts by the industry to reduce GHG emissions and slow the spread of toxic tailings ponds at oil sands plants.

"It is the most open dialogue we've had — meaningful discussions," he told reporters.

U.S. legislators also gave a lift to Alberta's lobbying efforts following the PNWER summit, when a group of them received a guided tour of the oil sands.

Gary Mar, the Alberta government's envoy in Washington, D.C., said the province wanted to "showcase the technology and innovation" that accompanies oil sands development.

Mike Schaufler, a Democratic member of the Oregon House of Representatives, said he was impressed by the technological advances and the sophisticated pipeline system that carries Alberta crude to the U.S.

"I am more comfortable buying oil from Alberta, which shares similar environmental goals with the U.S., than from foreign sources," Schaufler said.

Meanwhile, the Canada West Foundation, a non-partisan research organization, has issued a new study showing that over the past year, when the oil sands have attracted more global attention than ever before, the world news media carried 4,015 oil sands-related stories — 54.6 percent negative, 31.4 percent positive and 14 percent neutral.

The tally is "probably a day in the life of Tiger Woods," wryly observed foundation Chief Executive Officer Roger Gibbins.

The harshest of that coverage occurred within Canada, said Don Thompson, president of the Oil Sands Developers Group, adding: "I always wonder about why Canadians are so negative about themselves and that includes stories about the oil sands."

The most negative reporting showed up in the web media, where environmental nongovernment organizations are very active and was least evident in the conventional international media.

Thompson said that Canadians — contrary to the tone of the media coverage — overwhelmingly support development of the oil sands, provided that is done in a responsible manner.

He said a good deal of coverage "is based on misrepresentation, manipulation of data by environmental advocacy groups," while the media fails to balance off that criticism "by taking a look at the real science and the real facts." ●

Contact Gary Park through publisher@petroleumnews.com

● PIPELINES & DOWNSTREAM

Enbridge in a sticky fix after pipeline rupture

By GARY PARK

For Petroleum News

Listen closely and you can probably still catch an echo of the groaning in the downtown Calgary headquarters of Enbridge.

There's no good time for an energy carrier to fess up to a pipeline rupture, resulting in a spill of 3 million liters into a tributary, then into Michigan's Kalamazoo River and prompting Gov. Jennifer Granholm to declare a state of disaster. But, can anyone think of a worse time?

It didn't help that Granholm chastised Enbridge for an "anemic" response.

Enbridge Chief Executive Officer Pat Daniel — needing no reminders from ex-BP boss Tony Hayward of how not to handle a crisis — made a hurried trip to Battle Creek, Mich., the epicenter of the spill.

From there, first thing on July 28, he had the awkward job of trying to remain upbeat during a conference call on Enbridge's second-quarter earnings.

What he carefully didn't do was downplay the incident.

Daniel: 'serious … significant matter'

He said the July 26 spill is a "very serious and significant matter," and put himself in the front lines of the emergency response efforts, doubling the number of people involved in cleaning up the mess at the same time the operations were having to contend with rising floodwaters.

The longer-term impact of the Michigan events is an even greater challenge as Enbridge steps up efforts to deal with opposition from First Nations and environmentalists to its planned Northern Gateway pipeline to carry 525,000 barrels per day of bitumen across Alberta and British Columbia to the deepwater post at Kitimat for tanker shipment to Asian markets.

Already faced with opponents who have vowed to prevent the construction of the pipeline across streams, rivers and the traditional lands of about 50 Native communities and to make permanent a moratorium on oil tankers in British Columbia's coastal waters, Enbridge has just seen the road ahead grow even more daunting.

Daniel said the Northern Gateway application, now before Canada's National Energy Board and targeting a 2015 in-service date, is now faced with an even tougher job to convince First Nations and "other interested parties" of the "national significance and importance" of the project in opening up markets outside the United States for Alberta bitumen products.

He said Enbridge will waste no time explaining to its opponents what caused the Michigan accident and what the company will do to prevent a repetition by refining its line inspections, inspection periods and pipeline control.

Rail under consideration

The spill also coincided with word that the Alberta government, producers and railway companies are again exploring the possibility of delivering bitumen by rail to British Columbia ports.

Alberta Energy Minister Ron Liepert said his government is open to all means of accessing Asian markets, while Don Thompson, president of the Oil Sands Developers Group, said rail is viable and competitive with pipelines and is worth exploring as the U.S. market for Canadian crude "becomes constrained."

Brenda Kenny, president of the Canadian Energy Pipeline Association, was less enthusiastic, rating pipelines as "by far" the safest, most economical option.

Daniel said rail might help producers over the short-term to open up new markets, but said the option could not carry crude in sufficient volumes "to improve pricing for Western Canadian producers." ●

Contact Gary Park through publisher@petroleumnews.com

● FINANCE & ECONOMY

Encana sticks to strategy

By GARY PARK

For Petroleum News

It was one of those rare occasions when Encana, a pacesetter in developing its unconventional gas resources that sprawl across North America, found disfavor among its shareholders.

In three straight trading days on the Toronto Stock Exchange, Encana shares were trimmed by a total of nearly 8 percent as investors delivered a sharp rebuke.

They reacted to the company's reported second-quarter net loss of US$505 million and an operating profit that was short of analysts' expectations, along with a decision to pump another $500 million into its capital budget ($300 million earmarked for northeastern British Columbia and the rest for the United States) of $4.5 billion at a time when gas prices continue to flounder.

And the outlook is far from cheerful, according to Chris Theal, managing director of oil and gas research at Macquarie Capital Markets, who sees company profitability being squeezed in coming months, posing a challenge for shareholders to "warm up to the market share strategy."

RANDY ERESMAN

While saluting Encana for lowering costs at the same time it was increasing production, suggested the weakness on the shares stems from the company's decision to spend "more aggressively into an oversupplied market."

Sell recommendation

Goldman Sachs has taken an even tougher line, recommending that investors sell their Encana shares, despite the company's goal of doubling its per-share gas production over the next five years.

Lanny Pendill, an analyst with Edward Jones, in St. Louis, Mo., thought the market reaction was driven by short-term money "that's not willing to wait for long-term benefits," arguing that the extra money spent this year by Encana will position the company to produce in later years when prices should be higher.

Encana's second-quarter cash flow dropped 15 percent from a year earlier to $1.2 billion and operating profit tumbled 80 percent to $81 million.

Chief Executive Officer Randy Eresman acknowledged there could be tough times ahead for gas prices, announcing that Encana has lowered its 2010 forecast to $5 per thousand cubic feet from $5.75.

On the positive side, Encana trimmed its operating cost guidance for 2010 from 90 cents per thousand cubic feet to 80 cents, giving it a 9 percent return on New York Mercantile Exchange prices of $3.85 per million British thermal units.

'Gas factories'

Sitting on an estimated 18 years of drilling prospects, Encana sees no reason to question its strategy, which is expected to involve "gas factories" that will take a manufacturing approach by drilling, completing and tying in multiple horizontal wells that will be produced from a single surface location, where Encana and its service providers can optimize every part of the process.

Eresman has said Encana believes it is "only scratching the surface of economies of scale that we ultimately expect to achieve. Our gas factory approach will lead to reduced costs, improved efficiencies, further innovation and reduced surface disturbance."

Its strategy is also linked to joint ventures with Apache, Koreas Gas (which plans to spend C$565 million over the next three years to develop Encana resources) and China National Petroleum Corp., which has signed a memorandum of understanding to negotiate a potential joint venture investment for plays in Horn River, Greater Sierra and Cutbank Ridge in northeastern British Columbia.

Eresman said discussions with CNPC are "developing very well" towards a significant, multiyear partnership.

see **ENCANA** *page 10*

● PIPELINES & DOWNSTREAM

Alyeska planning safety review on TAPS

Operator of the 800-mile pipeline looking at valves, pumps and leak detection, spurred by request from Sen. Lisa Murkowski

By ERIC LIDJI

For Petroleum News

As scrutiny increases in the wake of operational issues, Sen. Lisa Murkowski wants the operator of the trans-Alaska oil pipeline immediately review the safety of the line.

Following a July 26 meeting, Murkowski said Kevin Hostler, the outgoing president of Alyeska Pipeline Service Co., the consortium that runs the pipeline, agreed to "conduct an immediate review of safety and maintenance risks and procedures for the oil pipeline.

Murkowski specifically listed several areas up for review:

- The remote gate valves, which isolate segments of the 800-mile pipeline to limit spills;
- The capacity of pump station relief tanks capacity;
- The system to monitor pipeline pressures;
- The reliability of pipeline control systems;
- Leak detections along the pipeline; and
- Power generation, distribution and backup.

Hostler is retiring from the company in September.

An Alyeska spokesperson told the Associated Press that a third party would conduct the review, which Alyeska had been planning since a shutdown of the pipeline in May.

Oil did not hit the ground

Many of those issues directly relate to a May incident where a power outage triggered a relief valve that lead to a tank overflowing, eventually shutting down the entire pipeline.

Although it occurred in the spring, the event has gained attention in recent weeks as the subject of a congressional hearing and national news reports, and drawing criticism from Rep. David Guttenberg, a Fairbanks Democrat who once worked for Alyeska.

But contrary to reports from national news outlets and a congressional subcommittee, the pipeline did not spill 5,000 barrels of oil onto the ground near Delta Junction, but rather into a lined pit designed as a back-up system for overflows. Such an overflow occurred on May 25, as Alyeska crews performed scheduled maintenance at Pump Station 9.

"We'll put out a final sit rep once we have a good volume estimation on the amount released." **—Tom DeRuyter, Alaska Department of Environmental Conservation**

During a test of the fire systems, the power went out, triggering a relief valve that sent oil into an overflow tank. Because power was out at the pump station, the command center in Anchorage couldn't see the tank filling up, and didn't see it eventually overflow.

As CNN reported on July 26, "about 5,000 barrels then leaked onto the ground nearby." The House Subcommittee on Railroads, Pipelines and Hazardous Materials, under the Transportation and Infrastructure Committee, made similar claims at a July 15 hearing.

However, the oil didn't overflow onto unprotected ground, but rather into "secondary containment," a lined pit designed for such an event, filled with gravel and surrounded by berms, according to Tom DeRuyter, of the Department of Environmental Conservation, and a member of the state response team that filed five situation reports on the incident.

After excavating the gravel, DEC and Alyeska found rips in the lining, but DeRuyter said their investigation hasn't yet determined whether those rips existed before the oil overflowed into the pit, or were caused by the excavating equipment removing the gravel.

The oil that overflowed into the pit was recovered within a week, but recovering the oil entrained in the gravel took longer, requiring a sump pump and a drainage system. "We'll put out a final sit rep once we have a good volume estimation on the amount released," DeRuyter said. That report should tell how much oil got through the holes into the soil. ●

Contact Eric Lidji at ericlidji@mac.com

NATURAL GAS

DCOM taking comments on North Fork line

A proposed pipeline to market natural gas in the southern Kenai Peninsula is up for review and public comments under the Alaska Coastal Management Program.

Anchor Point Energy, a subsidiary of independent Armstrong Cook Inlet, plans to build a 7.4-mile dual pipeline from the production pad at its North Fork unit to an area outside of Anchor Point, where it would connect with a proposed Enstar Natural Gas extension.

The North Fork unit is some 10 miles north of the city of Homer.

Almost entirely buried

The North Fork pipeline would be almost entirely buried, and would follow existing rights of way through state and Cook Inlet Region Inc. land. Anchor Point Energy is asking for a 50-foot-wide right of way during construction, reduced to a permanent 20-foot right of way.

This proposed route sits entirely within the drainage basin of the Anchor River and the North Fork River, one of its tributaries. The proposed pipeline would cross five streams, including the North Fork River. The pipeline would run under these streams. Anchor Point Energy plans to drill horizontally under the North Fork River and dig trenches beneath the four smaller streams during the winter, when they are frozen to the bottom.

The company wants to begin construction in September.

The state Division of Coastal and Ocean Management is taking comments on the proposed pipeline through Aug. 19 and plans to issue a final ruling by Sept. 8.

—ERIC LIDJI

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ALPINE

involves using a phased approach to developing the complex Nanuq reservoir, the report says.

However, no new wells were drilled in either the Nanuq or Kuparuk reservoirs in 2009 and ConocoPhillips plans to drill one new horizontal production well in the Kuparuk in 2010.

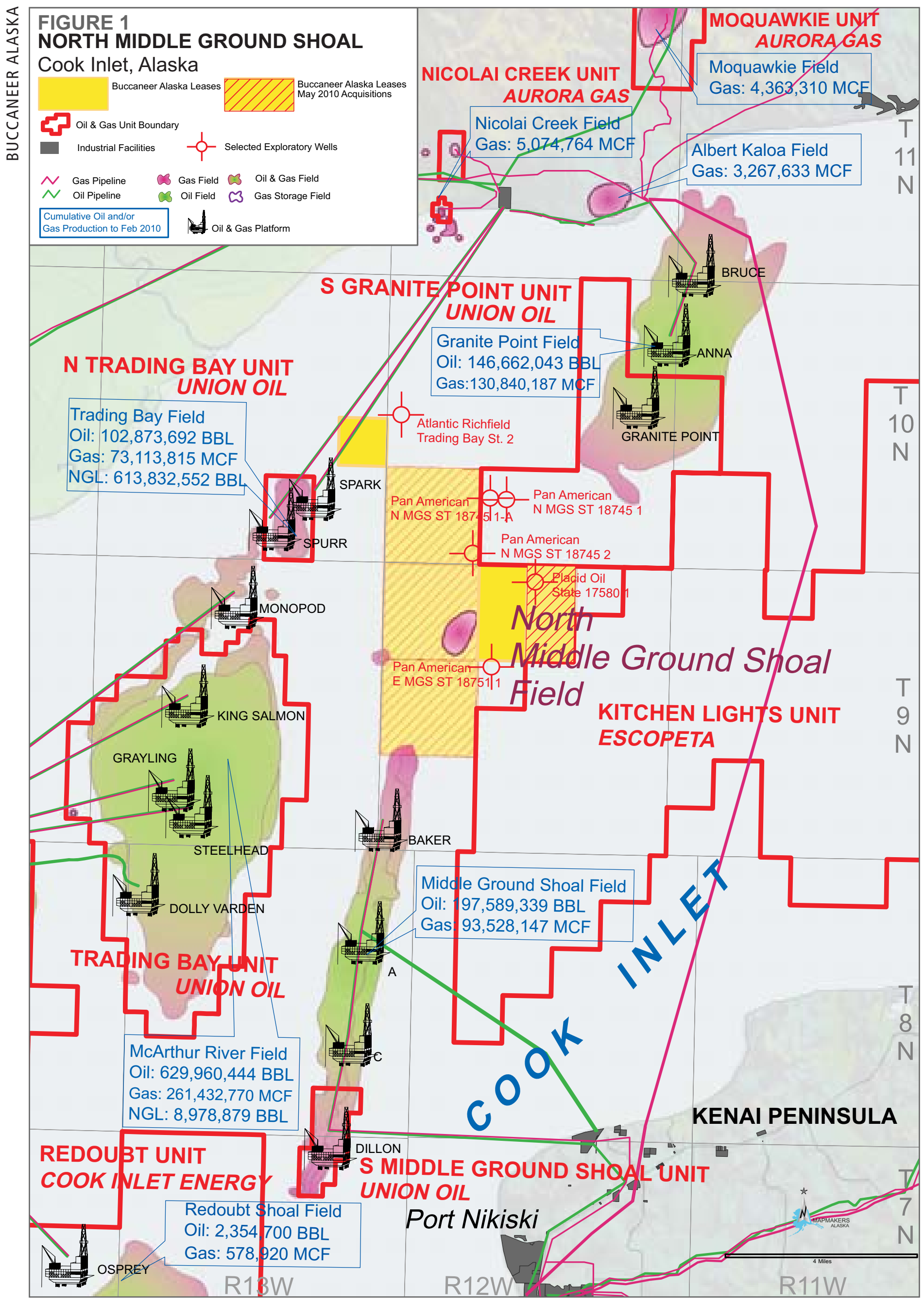
Performance of the Qannik satellite has met expectations, with an average daily production of 2,700 barrels of oil in 2009. ConocoPhillips has so far developed 5,000 acres of the Qannik reservoir using eight new horizontal wells and one existing exploration well, with six of the wells operating as producers and three as water injectors, the report says. ●

Contact Alan Bailey at abailey@petroleumnews.com

● EXPLORATION & PRODUCTION

Buccaneer applies for 2 Cook Inlet units

Company which first acquired acreage earlier this year is now working two projects, both adjacent to existing inlet production



By KRISTEN NELSON

Petroleum News

Buccaneer Alaska LLC has applied to form two units in Cook Inlet, the Southern Cross unit and the Northwest Cook Inlet unit.

The company said in a July 27 release that it is working on permitting and aims to accelerate time to first production from its Cook Inlet acreage, possibly through access to an existing platform at the Southern Cross acreage and access to nearby infrastructure at North Cook Inlet.

Buccaneer, a subsidiary of Sydney, Australia-based Buccaneer Energy, began acquiring leases in Cook Inlet early this year with a purchase of Stellar Oil and Gas acreage; it has since acquired acreage from other companies and at the state's Cook Inlet areawide oil and gas lease sale in May.

Southern Cross, which Buccaneer initially called North Middle Ground Shoal, includes five leases in Cook Inlet west of the producing South Granite Point unit, operated by Chevron subsidiary Union Oil Company of California, and the Kitchen Lights unit where exploration drilling is proposed by operator Escopeta.

Northwest Cook Inlet includes six leases in an arc north and northeast of the ConocoPhillips Alaska-operated North Cook Inlet unit, which produces gas from the Tyonek platform.

Southern Cross

In its unit application, Buccaneer said it has some 180 miles of 2-D seismic data and 51 square miles of 3-D data at Southern Cross, and "has identified a potentially commercial accumulation of hydrocarbons on the northern end of the Middle Ground Shoal structure" some two to five miles north of the Baker platform in the Middle Ground Shoal field. Buccaneer described the Southern Cross prospect as "a northward continuation of the Middle Ground Shoal field, a tight fold with dips up to and perhaps beyond 90 degrees on the west flank."

The 3-D seismic over the area was recorded in 1998 by Force Energy and

Buccaneer said the Northwest Cook Inlet unit "is a low risk project given that the Beluga gas sands in the North Cook Inlet Field extend to the northwest into the unit area, are within structural closure, and should be at virgin pressure."

Buccaneer said it recently licensed the data through the current owner, Cook Inlet Energy.

Southern Cross targets gas in the Tyonek formation and oil in the Hemlock formation.

Buccaneer said it plans to drill the first well to the pre-Tertiary formation, which — if the well is one of the first three drilled to the pre-Tertiary from a jack-up rig — would qualify the company for a credit of $25 million, $22.5 million or $20 million, depending on whether the well is the first, second or third drilled and eligible for credits established by the Alaska Legislature earlier this year in Senate Bill 309.

Buccaneer has 100 percent working interest in five leases in the proposed Southern Cross unit, a total of some 10,109 acres.

Without the unit, two of the leases expire at the end of September.

Southern Cross plans

Buccaneer proposes to drill an initial well in the unit area before Sept. 30, 2012. By Sept. 30, 2011, the company would complete permitting necessary for drilling, reprocess the 3-D data and provide evidence of a rig/drilling commitment that would enable it to drill a well at Southern Cross not later than Sept. 30, 2012.

The well to be completed by Sept. 30, 2012, would be to the pre-Tertiary interval.

If Buccaneer does not provide evidence of its commitment to drill the well by Sept. 30, 2011, the unit would automatically terminate and the two leases with expiration dates of Sept. 30, 2010, ADL 390379 and ADL 390370, would expire.

If the September 2011 commitments are met but the well is not drilled by Sept. 30, 2012, in addition to unit termination and expiration of the two named leases, the working interest owners would pay the state $10 per acre for the leases at

see BUCCANEER page 11

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ENCANA

"The depth and breadth of Encana's existing portfolio of assets means that at our current development pace of about 1,300 wells per year we would anticipate drilling wells for more than 18 years to access all of our best opportunities," he said.

"This, we believe, is simply too long for our shareholders to access that value. Our joint venture activity, which has brought us about $4 billion in capital investment over the past three years ... will allow us to accelerate our development timeline." ●

Contact Gary Park through publisher@petroleumnews.com

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BUCCANEER

Southern Cross which would have expired without unit formation.

In the third year, by Sept. 30, 2013, Buccaneer would determine through well test data that the Tyonek-Hemlock-pre-Tertiary interval is commercial and seek approval for a participating area within the unit.

In the fourth year of the plan, before Sept. 30, 2014, Buccaneer said it would drill a second well or would shoot a new 3-D seismic survey. A revised initial unit plan would be submitted, including a plan of development for lands within the participating area and an exploration plan for lands outside the participating area.

In the fifth year of the initial plan, by Sept. 30, 2015, Buccaneer would submit necessary applications and a plan of operations for construction of pipelines and infrastructure to support commercial production from the Southern Cross participating area.

The company has between 87.5 percent and 100 percent working interest in the six leases in the proposed Northwest Cook Inlet unit, a total of some 10,008 acres.

Northwest Cook Inlet

In its Northwest Cook Init unit application, Buccaneer said it has some 1,000 miles of 2-D seismic and based on interpretation of that data and analysis of existing wells on the North Cook Inlet structure, it has "identified a potentially commercial accumulation of hydrocarbons on the north and north west end of the North Cook Inlet structure" some three to six miles north of the Tyonek platform in ConocoPhillips' North Cook Inlet unit.

The company said the Norwest Cook Inlet unit area is "a northward continuation of the North Cook Inlet field in the Sterling-Beluga formations and the Tyonek Deep field in the Tyonek-Hemlock formations."

Buccaneer's first well will target a potential gas source in the Beluga formation.

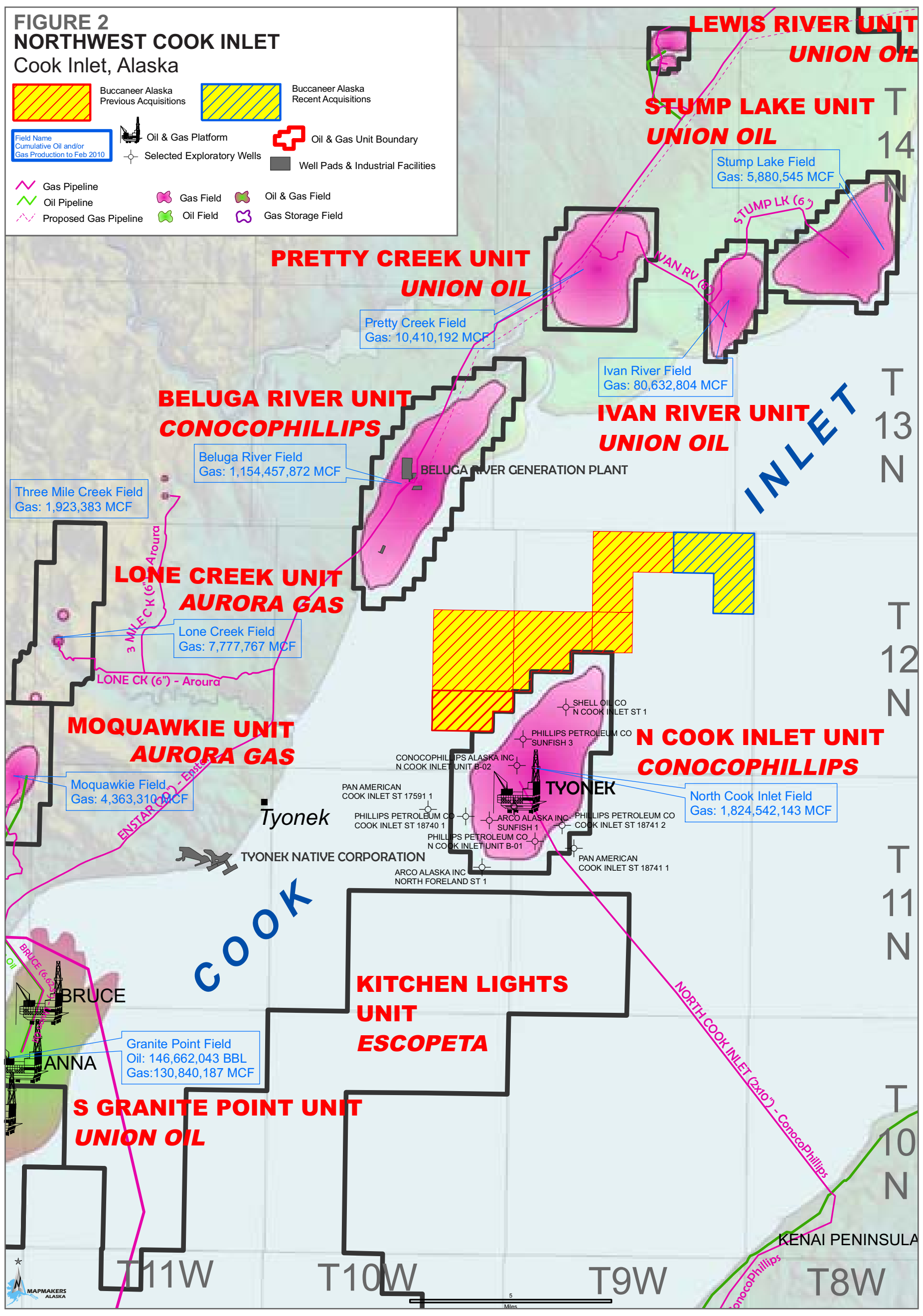
The company has between 87.5 percent and 100 percent working interest in the six leases in the proposed Northwest Cook Inlet unit, a total of some 10,008 acres.

First well by Sept. 30, 2012

As with the Southern Cross unit, Buccaneer commits to drilling the first well at the Northwest Cook Inlet unit by Sept. 30, 2012, and commits to obtain all necessary permits by Sept. 30, 2011, including "evidence of a rig/drilling commitment" by the unit operator.

The unit would terminate and ADL 390384 would expire if the Sept. 30, 2011, commitments are not made, and if the initial well is not drilled by Sept. 30, 2012, the same termination and expiration would occur, and in addition the working interest owners would pay the state $10 an acre for the expired state lease acreage within the unit.

During the third year, before Sept. 30, 2013, the operator would test production formations in the initial well and apply for a participating area within the unit. The fourth year plan calls for a second well or a 3-D seismic survey and in the fifth year, before Sept. 30, 2015, the unit operator would apply for construction of pipelines and infrastructure for commercial production.



BUCCANEER ALASKA

Low-risk project

Buccaneer said the Northwest Cook Inlet unit "is a low risk project given that the Beluga gas sands in the North Cook Inlet Field extend to the northwest into the unit area, are within structural closure, and should be at virgin pressure."

The company also noted in its unit application that the area is between the Beluga River gas field and the North Cook Inlet gas field.

"The Beluga sands consist of fluvial channels oriented in a northeast-southwest direction," Buccaneer said. "Such channels in the Beluga formation are productive in the prolific North Cook Inlet gas field."

The company said the Beluga formation thickens to the northwest toward the Beluga River gas field, and it expects the Beluga in the Northwest Cook Inlet unit "to contain more sands than on the crest of the NCI structure to the southeast." ●

Contact Kristen Nelson at knelson@petroleumnews.com

GOVERNMENT

Service firms challenge new moratorium

Hornbeck Offshore Services and several other oilfield services companies operating in the Gulf of Mexico have challenged the U.S. Department of the Interior's new deepwater outer continental shelf drilling moratorium, announced by Interior Secretary Ken Salazar July 12.

In a July 26 filing with the Court of Appeals for the 5th Circuit, the service companies said that the court should reject a request by Interior to lift an injunction against an earlier moratorium — in parallel with announcing the new moratorium, Interior had claimed that the appeal against the earlier moratorium was moot since, when issuing the new moratorium, Interior had rescinded the moratorium under appeal.

Interior cannot sidestep the appeal by simply issuing a new moratorium, the plaintiffs in the appeal told the court.

"The alleged 'new' moratorium issued by appellant Secretary Salazar on July 12, 2010, is a mirror image of the May 28th moratorium that already has been enjoined," the plaintiffs said.

The earlier moratorium banned for six months all new drilling on the U.S. outer continental shelf in water more than 500 feet deep. The new moratorium bans until Nov. 30 all OCS drilling done from floating facilities and requiring the use of blowout preventers, in effect imposing the same drilling restrictions as the earlier mora-

see **CHALLENGE** *page 15*

● GOVERNMENT

Pushing Arctic sovereignty

NWT premier urges Canadian government to be more vocal about northern claims; Coast Guard icebreaker sets out on 4-month mission

By GARY PARK
For Petroleum News

The Canadian government needs to be more assertive in advancing its Arctic sovereignty claims, using the Mackenzie Gas Project as a key element of that strategy, Northwest Territories Premier Floyd Roland told a conference of government leaders from the United States and Canadian northwest.

As foreign governments and industries increasingly turn their attention to Arctic natural resources, Ottawa should "step up and show some sovereignty" by funding projects such as air patrols, road construction and the MGP, he told the Pacific Northwest Economic Region conference in Calgary in July.

Roland said the major projects are beyond the financial capacity of the NWT government, leaving the Canadian government to make them happen.

He listed the MGP as the best hope on the horizon to stimulate economic development and said he expects the National Energy Board will deliver a positive verdict this fall when it releases the final regulatory recommendations.

But Roland conceded NWT business leaders are concerned that a competing project from Alaska to the Lower 48 could overtake the MGP.

"The fear that comes up at times is that the American government is very positive in talking about (the Alaska) pipeline and about incentives, while our Canadian government is much more reserved and hasn't been as vocal in that area," he said.

Alberta's Sustainable Resource Minister Mel Knight said his government supports both the Alaska and Mackenzie projects because of the opportunity they create for Alberta to serve as a collection, processing, storage and distribution center for gas deliveries throughout North America.

Four-month mission

The Canadian government's commitment to promote Arctic sovereignty took another step forward July 19 when the Canadian Coast Guard's flagship Louis S. St-Laurent left Newfoundland for a four-month scientific mission by a team of scientists, including biologists, oceanographers and hydrographers.

The mission will test ice, water and plankton by surveying the ocean bottom and submitting its data to the World Court as part of the long-term international effort to resolve Arctic boundaries.

Marc Rothwell, captain of the icebreaker, said the battle for jurisdiction will be won through a peaceful process and be based on scientific evidence.

Separately, Natural Resources Canada has been accused of breaking its promise to the Inuit to revise plans for seismic testing in Lancaster Sound, which lies between Devon Island and Baffin Island.

Okalik Eegeesuiak, president of the Qikiqtani Inuit Association, said NRC should now expect another outcry from Arctic community associations, which are troubled by the possible impact on marine wildlife if ever oil and natural gas exploration and development were approved.

Ron Elliott, the Arctic member of the Nunavut legislature, said there is no point to consultations if community concerns are ignored.

Donald James, chief geologist with the Canada-Nunavut Geoscience Office, told the Canadian Broadcasting Corp. in June that the original plans to gather seismic data in Lancaster Sound had been scaled back by "making some significant modifications" to the survey.

Researchers have said any seismic data could support efforts to have Lancaster Sound designated as a marine conservation area. ●

Contact Gary Park through publisher@petroleumnews.com

US, Canadian scientists map Arctic seafloor

U.S. COAST GUARD

Canadian Coast Guard's flagship icebreaker Louis S. St-Laurent (foreground) and U.S. Coast Guard Cutter Healy

U.S. and Canadian scientists will map the Arctic seafloor this summer, gathering data to help define the outer limits of the continental shelf.

The U.S. Geological Survey said in a July 26 press release that under the United Nations Convention on the Law of the Sea, coastal nations automatically have a continental shelf out 200 nautical miles, or to a maritime boundary.

However, nations are entitled to an "extended continental shelf" beyond 200 nautical miles if certain criteria are met.

USGS is the lead science agency for the United States in the 2010 mission.

"In this expedition, Canada and the U.S. are working together to determine the extended continental shelf in the Arctic to better determine where the Convention's criteria can be met," said USGS scientist Brian Edwards, chief scientist on the U.S. Coast Guard Cutter Healy.

USGS said the Healy would sail Aug. 2 through Sept. 6, meeting up with the Canadian Coast Guard's Louis S. St-Laurent at sea. The ships will alternately break through the Arctic sea ice for each other, with the Healy mapping the shape of the seafloor using a multibeam echo sounder and the Louis S. St-Laurent collecting multichannel seismic reflection and refraction data to determine sediment thickness.

USGS said this is the third year the U.S. and Canada have collaborated in extended continental shelf data collection in the Arctic. The U.S. has independently been collecting single ice breaker data in the Arctic since 2003.

"The Arctic Ocean is an area of great interest for science, resource conservation, and possible economic development," said USGS scientist Deborah Hutchinson. "Because there is an area with considerable overlap between the U.S. and Canadian extended continental shelves, it makes sense to share data sets and work together in remote and challenging environments of the Arctic Ocean."

USGS scientist Jonathan Childs, who is leading the seismic data operations team for the 2010 mission, said: "This is the last year working the Canada basin north of Alaska, and in 2011, we'll collect data together with Canada in the area north of the Canada basin around the Alpha Ridge."

—PETROLEUM NEWS

● PIPELINES & DOWNSTREAM

CPAI requesting in-state tariff hike

Third rate increase in 21 months would increase shipping rates within Alaska by 130% above most recently approved rates

By ERIC LIDJI
For Petroleum News

ConocoPhillips wants to increase shipping rates on the trans-Alaska oil pipeline for the third time in three years. The company is asking state regulators for permission to increase the tariff on North Slope oil bound for markets within Alaska by 12 percent.

ConocoPhillips said the increase is needed because throughput on the pipeline continues to fall while costs continue to rise, the same reasons cited for increases requested in 2008 and 2009, but also because of "another substantial increase" in property tax valuations, a new reason offered this year in the wake of a May 2010 ruling by an Alaska Superior Court judge more than doubling the assessed value of the trans-Alaska pipeline system.

The proposed increase would bring the cost to ship a barrel of oil from the North Slope to North Pole to $2.86, up from $2.55, while shipping to locations in Valdez would increase to about $4.48, depending on final destination, up from the previous rate of $3.98.

ConocoPhillips wants the increase to go into effect on Aug. 22.

The proposed increase would bring the cost to ship a barrel of oil from the North Slope to North Pole to $2.86, up from $2.55, while shipping to locations in Valdez would increase to about $4.48, depending on final destination, up from the previous rate of $3.98.

A triple-layer rate case

The request adds another layer of complexity to shipping rates on the pipeline.

The request is ConocoPhillips' third over the past 21 months. If approved, it would represent a 130 percent jump in shipping rates since October 2008. At that time, the company asked for a 57 percent increase in rates that had been in place since 2002.

That request was unique.

In 1986, the state and the five owners of the pipeline reached a settlement on how to set shipping rates, ending a decade of litigation. A subsequent ruling in 2002, though, changed the system for calculating rates in the future. Between 2002 and 2008, ConocoPhillips and the other owners kept filing rate increases using the original 1986 system. The Regulatory Commission of Alaska, in turn, rejected each of those filings.

In 2008, four of the owners again asked for rate increases using the new formula, saying shipping rates needed to increase to make up for falling throughput and rising costs.

The RCA approved those requests on a refundable basis while it investigated whether the increases were justified. In July 2009, with that investigation still under way, the four companies requested additional 29 percent increases on top of the 57 percent jump.

ConocoPhillips said the increase is needed because throughput on the pipeline continues to fall while costs continue to rise, and because of a recent hike in property tax valuations.

The RCA also approved that second round of increases on a refundable basis.

The newest increases, if approved, would create three levels of potentially refundable rates for ConocoPhillips. The last permanent rates, set in 2002, charge $1.25 to ship a barrel of oil from the North Slope to North Pole and $1.96 to ship to points in Valdez.

The newest request represents an additional 12 percent increase over the 2009 rates.

If the RCA ultimately rejected the temporary rate increases from 2008 and 2009, ConocoPhillips would be forced to refund millions of dollars to in-state shippers.

Additional complexities

And ConocoPhillips isn't alone.

If history is a guide, three other owners of the pipeline will submit identical rate increases in the near future. ConocoPhillips, ExxonMobil, Union Oil Company of California and Koch have been generally moving in lockstep on rate increases since late 2008.

The fifth owner, BP, which owns nearly half of the pipeline, has not been requesting rate increases. Each of the five companies owns an undivided share of the pipeline and sets its own rates, so long as the five rates combined stay below a predetermined limit.

Another twist is that those four companies are also asking the Federal Energy Regulatory Commission to increase shipping rates on Alaska oil bound for West Coast markets.

In an effort to reduce some of that complexity, the RCA is looking into merging the three cases on in-state shipping rates, and is considering holding a joint hearing with FERC.

That hearing would cover overlapping issues, such as whether and how to include costs of Strategic Reconfiguration in shipping rates. Strategic Reconfiguration is a multiyear effort to upgrade pipeline operations that is costing more and taking longer than expected.

By bringing the property tax valuation into the rate case, ConocoPhillips is adding another layer of complexity. In her May ruling, Superior Court Judge Sharon Gleason put the value of the pipeline system at $9.98 billion for 2006. The state Assessment Review Board previously put the value of the pipeline system at $4.3 billion for 2006.

Independent oil producers like Anadarko Petroleum and third-party refiners like Tesoro follow rate cases because higher shipping rates increase operating costs and reduce profits. The state also follows rate cases because royalties are based on the value of oil after tariffs, meaning the rate directly impacts the amount coming into the state treasury. ●

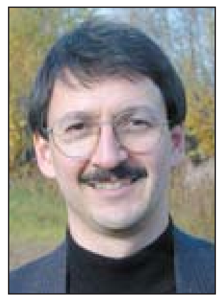
Contact Eric Lidji at ericlidji@mac.com

GOVERNMENT

Parnell adviser resigns amid hiring uproar

A top energy adviser to Gov. Sean Parnell is resigning amid questions about the legality of his hiring.

Gene Therriault, in a resignation letter dated July 28, said the "political turmoil" generated by Parnell detractors over his hiring last year has become a distraction and potential detriment to the governor, who faces election this year.


GENE THERRIAULT

"While I believe any judicial review of the circumstances surrounding my hire will be decided in favor of the administrative action we took in good faith, the debate over this issue should not divert Alaskans' attention from the important matters we have been working on," Therriault wrote.

His resignation is to take effect Aug. 2. A spokeswoman for Parnell said July 29 that the governor did not ask Therriault to step down.

His resignation is to take effect Aug. 2. A spokeswoman for Parnell said July 29 that the governor did not ask Therriault to step down.

Therriault resigned from the Legislature last year to take a newly created position as energy adviser with Parnell, who took office last summer. But his hiring drew renewed scrutiny earlier in July when Attorney General Dan Sullivan acknowledged shortcomings in the legal analysis and advice his department gave Parnell on hiring another former lawmaker, Nancy Dahlstrom, for a newly created position as military affairs adviser. Dahlstrom resigned.

The Anchorage Daily News published an editorial saying Therriault should step down.

Lawmakers are barred from taking posts created when they were in office. She and Therriault resigned their legislative seats before transferring to the executive branch.

While Sullivan said he believed his department's advice wasn't unreasonable, he said there was "appreciable risk" a court might disagree.

—THE ASSOCIATED PRESS

● ENVIRONMENT & SAFETY

Regulatory board says censorship a 'mistake'

Newfoundland regulator concedes it blundered in limiting information made public on emergency response plan for deepwater well

By GARY PARK
For Petroleum News

The public may never have felt more certain about its right to know the details of blowout response plans by offshore explorers.

Amid the fallout from the Gulf of Mexico catastrophe, it would seem, at the least, to be unwise for a regulatory body to black some details of Chevron Canada's plan to handle a spill, should one occur while it drills Canada's deepest offshore well in the Orphan basin, 250 miles northeast of St. John's.

And the stumble was quickly acknowledged by the Canada-Newfoundland and Labrador Offshore Petroleum Board, which has now decided it will release four response plans, covering 679 pages, "in the interest of the public's right to know."

This time the CNLOPB will make available the oil spill trajectory model and oil spill response management information — details that were previously denied to Postmedia News and the Canadian Broadcasting Corp.

CNLOPB Chief Executive Officer Max Ruelokke conceded the board realized that it had "been perhaps a little too cautious in terms of what we could release. By realizing that we made a mistake, we'll acknowledge that and move on."

He blamed the board's decision on extra pressures and scrutiny since BP's Macondo well blowout on April 20, adding the CNLOPB is also "spread pretty thin in terms of management resources."

Third-party information

Ruelokke said board staff were advised that the trajectory model showing where an Orphan basin spill could extend was third-party information that couldn't be released because it involved some work done and paid for by Chevron consultants — although the work was part of public documents.

Lorraine Michael, leader of Newfoundland's opposition New Democratic Party, questioned whether the board's about face would have occurred without public pressure.

"It's definitely in the public's right to know," she said. "What shocks me is that they thought at some point that it wasn't.

"Certainly our provincial government is known to be redacting quite a bit of material when it's requested," Michael said.

"So it's a culture that's out there in the bureaucracies and it may be in some corporations more than others, but it is definitely a mindset."

The CNLOPB said that in future it will only redact information considered "personal, proprietary or security sensitive," such as the layout of an emergency response center or the deck plans of ships cleaning up an oil spill.

One of the warnings contained in the response plan for the Lona O-55 well and Newfoundland's three producing offshore fields — Hibernia, Terra Nova and White Rose — is the threat posed by pack ice in Chevron's exploration license region.

Chevron warned that sea ice and fierce storms in the North Atlantic could hamper efforts to drill a relief well and clean up a major spill.

Chevron also said the region is susceptible to ocean cyclones known as "bombs" that exhibit characteristics similar to tropical storms, including hurricane-force winds.

"The feature that distinguishes the Orphan basin from other deepwater exploration and production areas is the combined occurrence of both storms and ice encroachment," Chevron said. "Both elements can be limiting factors in an oil spill response."

In its response plan for terra Nova, Petro-Canada (since taken over by Suncor Energy) estimates a blowout spilling about 30,000 barrels of oil per day would take 90 days to plug with a relief well. Suncor declines to say if that estimate still applies.

Chevron has told regulators it would take about 11 days for a drillship to reach the Orphan basin and start work on a relief well, but the company has given no estimate of how long that might take.

An environmental assessment commissioned by Chevron tested 14,600 possible trajectories for an oil slick and found that none would reach shore.

It said Chevron would "respond to a spill originating at the drill site and moving into international waters to the extent that logistical support is practical." ●

Contact Gary Park through publisher@petroleumnews.com

● EXPLORATION & PRODUCTION

Cook Inlet Energy revives Kustatan well

Well produces fuel gas for field operations; company and parent Miller invest up to $7 million so far on newly acquired properties

By WESLEY LOY
For Petroleum News

Anchorage-based Cook Inlet Energy has restored production from a natural gas well at its Kustatan field.

The KF-1 well, on the west side of Alaska's Cook Inlet, tested at 70,000 cubic feet per day of initial production, says a July 22 press release from Cook Inlet Energy's parent company, Miller Energy Resources of Huntsville, Tenn.

The well, which had been shut-in for almost a year, is located along the south plunging West McArthur River unit anticline and is completed as a single selective gas producer in the upper Tyonek sand, Miller said.

"There is always some concern whether or not a well will come back online after being shut-in for an extended period of time," said Scott M. Boruff, Miller's chief executive. "This is another example of our continued success in Alaska, as the KF-1 well was brought back into production without a hitch and at twice its historic production rate."

Cook Inlet Energy and Miller entered the Alaska oil and gas scene in December 2009, acquiring a collection of mostly shut-in Cook Inlet properties from Pacific Energy Resources, a California independent that was undergoing a bankruptcy liquidation.

Production from the KF-1 well previously was used as fuel gas for field operations, and that remains the case now that the well is producing again, David Hall, Cook Inlet Energy chief executive, told Petroleum News.

The gas well is located on a pad with the Kustatan production facility, which was built to generate power and process oil from the offshore Osprey platform, which was among the properties Cook Inlet Energy and Miller acquired.

Busy times

Cook Inlet Energy has been busy restoring production from oil wells in its West McArthur River unit. So far in 2010 it has announced successful recompletions of three wells: the WMRU-5 well, the WMRU-6 and the WMRU-1A. The workovers have brought production to more than 1,000 barrels of oil equivalent per day.

Now the company is close to finishing a fourth workover, this one involving the WMRU-7A well, Hall said. The plan is to test the well in a week or two, he said.

To date, Cook Inlet Energy and Miller have spent upwards of $7 million on their Alaska properties, Hall said.

The companies have a lot going on. At a state lease sale on May 26, Cook Inlet Energy was the high bidder on seven Cook Inlet tracts covering an estimated 27,000 acres. The winning bids tallied $908,800.

Miller, which touts itself as "a high growth oil and natural gas exploration, production and drilling company" focused on Cook Inlet and Tennessee's Appalachian basin, in May saw its shares listed on the tech-heavy NASDAQ exchange.

In recognition of the company's listing, Miller CEO Boruff was in New York on June 14 to ring the NASDAQ closing bell. ●

Contact Wesley Loy at wloy@petroleumnews.com

● NATURAL GAS

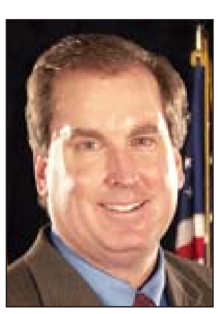
State has marginal open season role

Revenue commissioner: alignment of shippers, pipeline, at issue; bigger line better from state's perspective, Galvin tells chamber

By KRISTEN NELSON
Petroleum News

As important as the current open seasons are for an Alaska gas pipeline project, the state doesn't have much of a role in that alignment, Alaska Commissioner of Revenue Pat Galvin told the Anchorage Chamber of Commerce July 26.

Illustrating his point with a Venn diagram, the commissioner said the open season alignment is between shippers and the pipeline entity, and is focused on commercial terms and the route.



PAT GALVIN

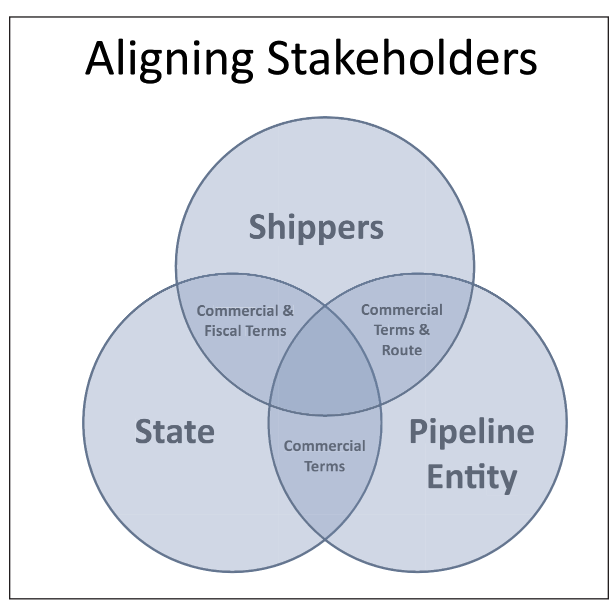
The open season for the Alaska Pipeline Project, the TransCanada-ExxonMobil project licensed under the Alaska Gasline Inducement Act, closed July 30; the open season for Denali, the ConocoPhillips-BP project, closes Oct. 4.

Both projects propose a line into Canada — existing pipelines are expected to have the capacity to carry Alaska North Slope natural gas to Lower 48 markets; the Alaska Pipeline Project also offers an option to Valdez, where gas would be liquefied for shipment as liquefied natural gas.

"The open season," Galvin said, "is an opportunity for the market to respond to those two options."

The other option that's being discussed is a bullet line, a smaller-capacity line which would bring North Slope gas only as far south as in-state markets.

Because of the resource available on the North Slope, "bigger is better with a gas pipeline," Galvin said. A larger line moves more gas, spreading the large investment for the product over more gas, thus reducing the transportation cost and lowering the cost of gas for consumers.



ALASKA DEPARTMENT OF REVENUE

Illustrating his point with a Venn diagram, Galvin said the open season alignment is between shippers and the pipeline entity, and is focused on commercial terms and the route.

That also means more economic gas for Alaskans, because taking gas off "a large mainline is going to be less expensive than having it off of a smaller line," he said.

And while a small-capacity line could move existing reserves from the North Slope, it wouldn't provide an opportunity for getting new gas to market.

"And when we open up that opportunity for that new gas to get to the market, that would create a new industry for Alaska … based upon gas development," Galvin said. The state would go from having just oil production to having both oil and gas production, creating "a much more diversified opportunity for businesses and entrepreneurs in the state."

The large-capacity natural gas pipeline would also impact oil production because with both North Slope oil and gas being produced for sale the cost of production is shared and the marginal cost is reduced, making "the overall production more economic — and more oil becomes economic to produce than it does when you only have an oil pipeline," Galvin said.

The alignments

Getting to a large-capacity gas project, a mainline into Canada and the Lower 48, requires alignment of the state, the shippers and the pipeline entity around a single project, he said.

Referring to the Venn diagram, which shows three intersecting circles, Galvin said at each juncture — between state and shippers, shippers and pipeline and state and pipeline, there are issues.

These issues have to be worked out.

The project will potentially spin off "hundreds of billions of dollars if not eventually trillions of dollars."

"The terms by which people make alignment have the ability to move billions of dollars between the parties, and therefore everybody is very careful and very concerned about what they're agreeing to, what they're locking in and what opportunities they may be losing by agreeing to something at any particular point in time," Galvin said.

Posturing around attempts to reach those alignments has been going on for a decade or more, he said.

What the state wants is to "get to a gas pipeline that protects the state's interests as soon as possible."

And the state wants to make sure that while negotiations around needed alignments take place, investments continue in design work, engineering and permitting.

That, Galvin said, is the purpose of the Alaska

see OPEN SEASON page 17

continued from page 11

CHALLENGE

torium, the plaintiffs said.

The plaintiffs originally appealed the May moratorium in Louisiana district court. But after a federal judge in that court imposed an injunction against the moratorium until the appeal was resolved, Interior appealed the injunction in the 5th Circuit court. A panel of 5th Circuit judges subsequently upheld the injunction.

—ALAN BAILEY

Petroleum news

Oil Patch Bits

Tom Maloney Named CH2M HILL Alaska Area Manager


TOM MALONEY

CH2M Hill, a global full-service consulting, design, construction, and operations firm, said July 27 that it has named Tom Maloney as Alaska area manager. In this role Maloney will be responsible for managing and developing client relationships in the energy, water, transportation, environmental, facilities and natural resources sectors. Maloney has been with CH2M HILL for 21 years, including serving as a senior project controller, corporate business manager, president of two operating companies, business development, and external affairs and government relations manager for Alaska. Active in the community, Maloney is president for the Resource Development Council, vice chairman of the Municipality of Anchorage Investment Advisory Commission and board member of the Alaska State Chamber of Commerce. Previously, he enjoyed multiple volunteer positions with Hilltop Ski Area, Junior Achievement, Habitat for Humanity and Anchorage Economic Development Corporation. CH2M HILL is one of the largest private employers in Alaska, with approximately 3,000 employees. In 2009, the firm was recognized as the Employer of the Year for Apprenticeship Training by the State of Alaska. The Anchorage office was opened in 1964.

Nalco to host two informative seminars in August

Nalco Co., in conjunction with Hach, Jaffa, and Delta P, will be hosting two information-packed seminars targeted to those involved in all aspects of boiler operation and steam generation, in Anchorage Aug. 24 at the Embassy Suites and in Fairbanks Aug. 26 at the Westmark Hotel. The focus will be on water treatment tools, inspection, and safety, which can positively impact production efficiency and profitability. Following introductory remarks, there will be breakout sessions covering: reverse osmosis, water chemistry testing, pump selection and maintenance, deaeration, boiler system construction and repair codes, ion exchange, boiler internal treatment steam and condensate systems, inspection and safety, and zero defect delivery. Each session will feature interactive discussions with participants and is approved for 0.6 CEU. Registration is $50, including training materials, breakfast, lunch and refreshments. For more information contact Jaimie Farrell at 907-563-9866 or jfarrell@nalco.com; or to register online go to www.nalco.com, and click on news and events.

Hall announced new Lounsbury & Associates surveyor

Lounsbury & Associates said July 22 that it welcomes James Hall, PLS, to its staff as

see OIL PATCH BITS page 18

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

● ASSOCIATIONS

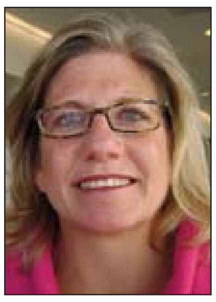
‘Energy reality tour’ hits Anchorage

US Chamber executive urges RDC audience to get involved to ward off unfriendly federal laws brewing in the wake of Gulf oil spill

By WESLEY LOY
For Petroleum News

Karen Harbert, the featured speaker at a recent Resource Development Council for Alaska luncheon, apologized to her audience in advance for causing indigestion with her speech.

Business and industry players, she said, had better get involved or else face some unfavorable new laws from Washington, D.C., in the wake of recent resource industry disasters including BP's Gulf of Mexico oil spill.


WESLEY LOY
KAREN HARBERT

The oil industry is experiencing a lockout from highly prospective acreage all around the country, she said.

"I pray the BP oil spill is not our Three Mile Island," said Harbert, referring to the 1979 accident that did much to stymie further development of the nuclear power industry.

30-state tour

Harbert is president of the U.S. Chamber of Commerce's Institute for 21st Century Energy. She previously served as a U.S. Department of Energy assistant secretary.

Part of Harbert's job is testifying before Congress, and keeping an eye on legislation the lawmakers are considering.

She told some 1,000 listeners at the RDC annual meeting July 21 in downtown Anchorage — the RDC is a nonprofit organization for the oil, mining, fishing, timber and tourism industries — that the energy sector and business in general are facing excessive and invasive laws and regulation.

To spread the word and urge business people to get involved, she's flying around the country on an "energy reality tour." The tour is expected to hit 30 states by the end of 2010.

In an interview with Petroleum News, Harbert said the BP spill and the West Virginia coal mine explosion in April that killed 29 men spurred the reality tour along.

Harbert, in her speech, ticked off a string of troubling problems dogging the nation and business community, from the $13 trillion national debt to 10 percent unemployment to a shortage of engineering graduates to what she termed the BANANA effect — Build Absolutely Nothing Anywhere Near Anything.

Aside from legislation burdensome to business, the Environmental Protection Agency is generating a regulatory and litigation "cascade," Harbert said.

U.S. Sen. Lisa Murkowski, R-Alaska, concurred. Speaking to the RDC crowd via video link from her Washington office, Murkowski said the EPA has begun 700 separate rulemakings in the past 15 months.

Call to action

One new proposal in Congress would hit the oil and gas industry with $80 billion in taxes, Harbert said.

"Because you guys are rich, right?" she told the RDC audience.

The government's moratorium on deepwater drilling is killing jobs, and legislation to prevent oil spills could go too far and do serious economic damage, Harbert said.

"So we have proposals in front of us that are shedding jobs, can potentially increase energy costs, can potentially increase imports," she said.

"I'm not optimistic that without a huge outpouring of support from the business community we will be able to get the message through that Americans support oil and gas exploration," she said. "Seventy percent of Americans still support onshore and offshore exploration."

Congress and many Americans simply don't see the priorities the same way, Harbert said.

"Energy is still very, very important to the American public, second to jobs," she said. "That should be a huge platform for policymakers to grab hold and do something sensible on energy. But instead they're focused on what the American public is not so focused on right now — climate change."

"We all want to be good environmental stewards. We just don't want to have climate legislation, regulation, litigation placed on us" in a way that could force people out of business, Harbert said.

She concluded: "Really what's at stake here is our investment climate. The decisions we make are going to be hard to undo, so we better make some smart ones."

For more information on the Institute for 21st Century Energy, visit www.energyxxi.org. ●

Contact Wesley Loy at wloy@petroleumnews.com

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OPEN SEASON

Gasline Inducement Act, AGIA.

"We want to see forward progress on a project that will meet the state's interests while these alignments are taking place."

AGIA required the licensee to commit in advance to moving the project through receipt of a Federal Energy Regulatory Commission certificate of convenience and necessity, irrespective of the success of an initial open season.

The state provided $500 million in matching funds against costs, putting "the money in front to get the project moving."

That AGIA process, Galvin said, focused on "the relationship between the state and the pipeline entity, to try to get alignment there in terms of the types of terms the state's going to be looking for in a pipeline to move it forward."

Open season results

Galvin said there are four possible results of an open season.

Shippers could submit bids basically accepting terms offered by the pipeline, "with minimal additional conditions." In that case, he said, shippers and the pipeline could probably sign precedent agreements quickly.

If the shippers submit bids with conditions, Galvin said negotiations would take place in the months following the open season and shippers and the pipeline would either reach agreement on the additional terms or eliminate the conditions put on bids by shippers.

Or, there might be some interest, "but not sufficient interest to actually denote that the project is completely viable." The question then becomes: "Is it something to do with the project, with the market, or with something else that the state could potentially react to and respond to?"

Then there could be no interest.

In that case "we'll have to investigate that with the potential shippers; we'll have to look at it from the standpoint of is this an issue with this project or is it an issue with the economics of getting North Slope gas to market at this time?" Galvin said.

But the "important thing in protecting the state's interests, is that while that evaluation takes place, while we are attempting to figure out what we need to do to speed up alignment, the project — at least the Alaska Pipeline Project — is obligated to continue to move forward, so that we don't lose time on that first gas, so that we're not left stranded waiting for the project to advance while people are trying to figure out what needs to be done to bring that alignment together."

Close of APP open season

When the Alaska Pipeline Project open season closes July 30, Galvin said he expects that very little will be announced, although he said the Alaska Pipeline Project has made it clear that if there are no bids it will "make it clear that the open season was unsuccessful and there were no bids submitted."

But if bids are submitted, that "kicks off a negotiation process — and a very competitive negotiation process as well, competitive in multiple ways," he said.

The pipeline is dealing with multiple customers who may be including different conditions on their bids. The pipeline won't want to share conditions one shipper has put on a bid while it's negotiating with other shippers.

Then there is a competing project "that is also out there simultaneously talking to these customers about what they can do to attract their business."

In addition, FERC requires pipelines to consider late bids.

"And so for all these reasons, we would expect that if there are bids submitted, the public announcements are going to be very general about the nature of the bids that came in."

On the issue of changes the state might make in its fiscal system, Galvin said his message has been consistent through the Palin and Parnell administrations: "If the shippers demonstrate that changes to the state's fiscal system are needed, then those changes can and should be done."

But, he said, the process needs to continue so fiscal terms don't "become a barrier for getting that alignment and that the state isn't put in a position of having to make concessions simply to see forward progress on the project." ●

Contact Kristen Nelson at knelson@petroleumnews.com

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SALE CHATTER

month or so about what is the right course of action to take. It is clear that this tragedy will leave BP a changed company, and that to move forward, particularly in the United States, it should do so under new leadership."

BP further announced that it sustained a $17.2 billion loss for the second quarter of 2010, compared to a $4.4 billion gain for the second quarter of 2009.

Divestment plans

BP said it intends to sell properties with total value of $25 billion to $30 billion. The total includes the $7 billion deal BP and Apache Corp. announced on July 20 for an assortment of assets in western Canada, Egypt and the Permian basin of Texas and New Mexico.

Future sale properties will come "primarily in the upstream business, and selected on the basis that they are worth more to other companies than to BP," the company said.

This process of "portfolio high grading" will leave the company with "a smaller but higher quality" exploration and production business, BP said.

"We have done a review of assets around the world," Dudley said in the July 27 news conference. He didn't specify, however, exactly where BP is looking to sell.

The company said it was taking a charge of $32.2 billion to reflect the impact of the Gulf disaster, including spill response costs to date of $2.9 billion and $29.3 billion in expected future costs such as damage claims, fines and lawsuits.

Some positive rays did manage to shine through on BP's day of big announcements.

For one thing, the leaking Macondo well has been capped with efforts now far along to seal it permanently.

BP also said its capital spending for 2010 and 2011 will be about $18 billion a year, "in line with previous forecasts."

The financial impact on BP has been very substantial, "but our businesses around the world are performing well and our cash flow is strong," said BP's chairman, Carl-Henric Svanberg.

Rampant Alaska speculation

A couple of weeks ago, the chatter out of Wall Street and London was that Apache might pay as much as much as $12 billion for BP properties on the North Slope.

That didn't happen, as Apache spent elsewhere.

But now, given BP's much higher divestiture target, the speculation seems hotter than ever that BP surely will sell its Prudhoe stake and perhaps its interest in other fields including the many Prudhoe satellites, the BP-operated Milne Point field and the ConocoPhillips-operated Kuparuk field.

Although BP is a minority owner, it operates vast Prudhoe.

State records show that BP holds a 26.36 percent working interest in the Prudhoe Bay unit, ExxonMobil owns 36.40 percent, ConocoPhillips owns 36.08 percent, and Chevron holds 1.16 percent.

BP, in its most recent annual report filed March 5 with the U.S. Securities and Exchange Commission, said its net share of production from Prudhoe Bay was 69,000 barrels per day in 2009.

Overall, BP's Alaska production was 181,000 barrels per day in 2009, with 45,000 barrels coming from Kuparuk, 24,000 from Milne Point and 43,000 from other sources such as the offshore Northstar field.

Aside from its interests in these fields, BP also holds other very important assets in connection with its Alaska operations, including a 46.9 percent stake in the 800-mile trans-Alaska pipeline, and partial ownership of a fleet of new double-hulled oil tankers.

The speculation is that BP will look to sell mature or declining assets such as Prudhoe.

"The most likely buyers," The New York Times wrote July 27 on its DealBook news service, are BP's partners in Prudhoe — ExxonMobil, ConocoPhillips and Chevron.

Not so fast

If past experience is any indication, however, a sale to these partners, particularly ConocoPhillips, could present difficult problems.

In 1999, after BP's takeover of Atlantic Richfield Co. was announced, the Federal Trade Commission stepped in with antitrust concerns. ARCO at the time held a big stakes in both Prudhoe and Kuparuk, two of the nation's largest oil fields. The FTC opposed the merger on grounds that BP could exert too much control over West Coast gasoline markets.

The solution was to carve out ARCO's Alaska assets and deal them to a third player, Phillips Petroleum out of Oklahoma.

But ExxonMobil temporarily threw that plan into disarray when it filed a lawsuit in ARCO's hometown of Los Angeles asserting that it had the right of first refusal to buy ARCO's North Slope properties but wasn't given the chance.

Eventually, ExxonMobil was satisfied, Phillips ultimately acquired ARCO Alaska, and Phillips in 2002 merged with Conoco to become what we known today as ConocoPhillips.

If BP does move to sell some or all of its Prudhoe stake, the transaction probably will be complex, with all the field's heavyweight owners having some say in the matter. And maybe government regulators, too. ●

Contact Wesley Loy at wloy@petroleumnews.com

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OIL PATCH BITS

project surveyor. Hall has 12 years of land surveying experience on a wide variety of projects — from solar, wind and natural resource development to construction surveys for highways and residential subdivisions. His experience includes projects throughout Nevada, Wyoming, New Mexico and Arizona. Hall began his education in Phoenix, Arizona and progressed with continuing education programs in the survey industry. Recently, he completed high-definition laser scanning of 46 bridges on I-215 in Las Vegas, Nev. His experience using laser scanning on forensic surveys, piping as-builts, topographic maps and more, is key to completing projects on time and under budget.

JAMES HALL

Founded in 1949, Lounsbury & Associates offers a range of surveying, engineering and planning services.

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SPURR GEOTHERMAL

Ormat says. In this case the holes will be about 3.75 inches in diameter.

Summer program

According to the company's earlier filed exploration plan, datasets collected from airborne surveys and fieldwork done during the summer of 2010 will help identify potential drilling locations. Fieldwork includes surface gravity measurements in the exploration region, the measurement of electrical noise, geologic mapping and water sampling. Airborne surveys include the laser measurement of landforms and the measurement of electromagnetic radiation from the land surface.

The new drilling plan says that Ormat has already identified candidate drilling sites, although the company may choose different locations after assessing updated geophysical and geochemical data gathered during the summer.

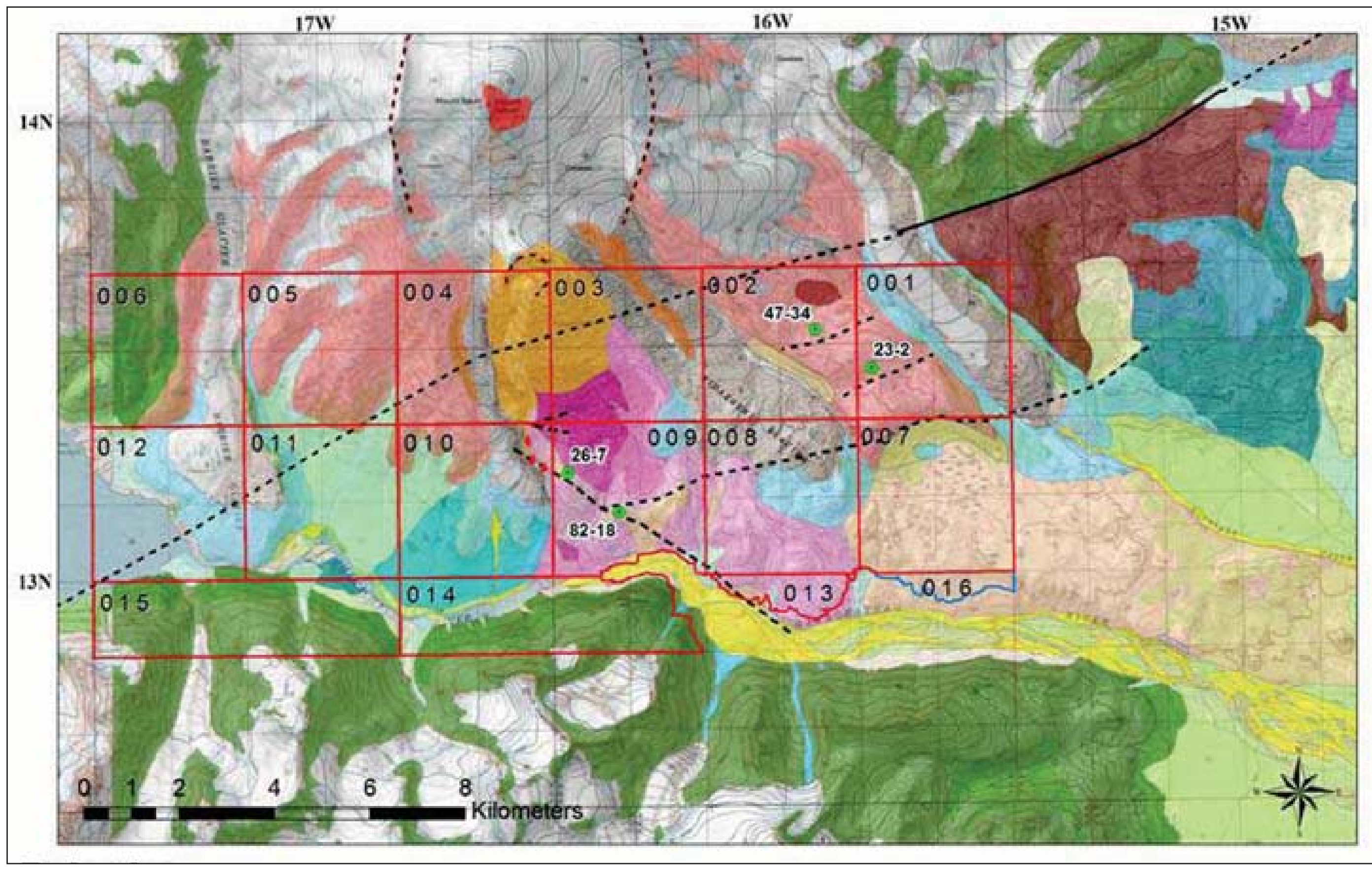
Drilling crews will operate from an on-mountain camp and will travel to each drilling site by helicopter, working at higher sites to start with, before drilling at the sites at lower elevations. Each core hole should take about five days to complete so that, even after factoring in some weather delays, it should be possible to complete the four-hole program within 30 days.

However, completion of the program this year does depend on reasonable weather conditions relatively late in the exploration season.

"The late timeframe is required in order to accommodate collection and analysis of summer 2010 phase one exploration data," Ormat says. "Ormat duly acknowledges the vagaries of weather in Alaska and is prepared to drill in inclement weather and/or move drilling activities to summer 2011."

After drilling each hole, project personnel will take subsurface temperature readings after two days and then again after two weeks. A geologist at base camp will log the rock cores retrieved from the holes, with the cores being later flown to Anchorage for storage in a state core repository.

—ALAN BAILEY



ORMAT NEVADA

Ormat Nevada's geothermal exploration area on the southern flanks of Mount Spurr, with the mountain's summit at the top left center. Potential core-hole sites are indicated with black numbers.

*Contact Alan Bailey
at abailey@petroleumnews.com*

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CINGSA

the facility starts in 2011, to meet the summer 2012 target to bring the facility on line.

Bought work package

TransCanada subsidiary, ANR Pipeline Co., had been working with Semco to build and operate the facility in the Sterling C sands of the Cannery Loop gas field, on the south side of the city of Kenai. But in April, under the terms of a memorandum of understanding with TransCanada, Semco bought out the work package for the project, retaining the name of Cook Inlet Natural Gas Storage, or CINGS, for the company that is building the facility and making CINGS a Semco subsidiary. That Semco subsidiary has now become a joint venture between Semco and MidAmerican under a new name: Cook Inlet Natural Gas Storage Alaska, or CINGSA.

"We are excited to be part of a project to provide improved gas deliverability to the customers in Southcentral Alaska," said Mark Hewett, president of MidAmerican Energy Pipeline Group, MidAmerican's natural gas subsidiaries. "This storage facility is an important transaction for MidAmerican Energy Holdings Company and to the ongoing development of energy infrastructure by the MidAmerican companies. We look forward to working closely with our partner to successfully develop this project."

Semco CEO and President George Schreiber said that CINGSA will prove important to Enstar and the Cook Inlet electric utilities as a factor in enabling the utilities to meet their customers' needs, especially when gas demand is high during the winter.

"This facility represents a significant commitment by Semco and MidAmerican," Schreiber said. "For Semco, this investment nearly doubles the size of our business in Alaska."

The CINGSA project will require an investment of $180 million, Semco and MidAmerican said.

Preliminary surface lease

The July 26 DNR notice says that the Division of Mining Land and Water has published a preliminary decision to issue a seven-acre surface lease with an associated pipeline easement, as part of the package of permits and leases that DNR is processing. The project is also being reviewed for consistency with the Alaska Coastal Management Program. Comments on the DNR package must be submitted by Aug. 24, DNR says.

The design of the new facility involves drilling five wells on a 5.9-acre pad on state land, for the injection and withdrawal of stored gas. A 16-inch pipeline will connect the wells to a neighboring gas compression and conditioning facility on 7.5 acres of land purchased from the University of Alaska. A 20-inch buried pipeline will carry gas between the facility and the nearby Kenai Nikiski pipeline on the Southcentral Alaska gas pipeline network.

The facility will provide gas storage services to third party customers. The RCA certificate application lists Enstar, Chugach Electric Association and Municipal Light & Power as initial customers, with Enstar using 70 percent of the initial storage capacity, Semco and MidAmerican said. ●

*Contact Alan Bailey
at abailey@petroleumnews.com*

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GAS FOUNDATION

Because the Mainline is regulated by Canada's National Energy Board, the returns from those shrinking volumes must be recovered by higher per-cubic-foot rates.

For example, transportation tolls from Alberta to Niagara rose by 45 percent in January and to Iroquois, a key export point in the U.S. Northeast, by 37 percent.

That progression undermines the ability of WCSB producers to remain competitive against commodity prices of C$3 per gigajoule in Alberta and United States producers who are much closer to the primary markets, especially as low-cost production from the Marcellus and other shale plays enters regions of the North American market that were once major outlets for WCSB gas.

Challenge to entire industry

Murray Newton, president of Canada's Industrial Gas Users Association, said the challenge is one the entire industry has to contend with as either producers and end users swallow a lower netback or toll increases flow "right through to the market."

TransCanada has been working over the last few months with its shippers to address the competitiveness of the Mainline and its Alberta network in hopes of reaching a consensus over the next two months before the NEB deals with a rate change proposal from TransCanada, which has declined to discuss the specifics.

However, TransCanada has indicated it is prepared to lower its eastern rates to compete with Marcellus gas. The customers have submitted their own counter-proposal.

In 2007, TransCanada reached a deal with shippers to set tolls on the Mainline at C$1 per gigajoule, with the ability to hike those rates depending on volume forecasts for the upcoming year. The current toll is C$1.65 per gigajoule.

In mid-spring, Max Feldman, TransCanada's senior vice president for Canadian and Eastern U.S. pipelines, said the key objectives of the continuing discussions are to lower tolls, introduce greater toll stability and certainty, and provide greater alignment between the pipeline and its shippers.

Reduction proposed

A comprehensive package submitted to the industry in March would result in a reduction of about C45 cents to C50 cents per gigajoule from Alberta to the Toronto market.

That reinforces the view of some observers that TransCanada is approaching a crunch point where rate increases would weaken its ability to cover operational costs.

Newton has described the current rate as "just out of the market" and unpredictable, resulting in a scramble for the exits by those who can de-contract out of the system.

But TransCanada is not without hope. The company's recently retired Chief Executive Officer Hal Kvisle said pipelines from the Horn River and Montney shale and tight gas plays in British Columbia are due onstream over the next two years, although the prospect of 2 billion cubic feet per day from those sources still means TransCanada will need 10 bcf per day of conventional gas from Alberta and 2 bcf per day from British Columbia to ensure a healthy gas industry in the WCSB. ●

Contact Gary Park through publisher@petroleumnews.com

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AURORA GAS

potential customer for the facility. And in April the Alaska Oil and Gas Conservation Commission issued its approval for the injection of gas into the Nicolai Creek facility.

"We're actually very encouraged by the developments that have occurred after the last six months at the legislative level and the DNR level. Physically everything is still in good shape, ready to go," Pfoff said.

Gas deliverability

Aurora's gas storage project is one of several initiatives addressing growing concerns that winter shortfalls in gas deliverability in Southcentral Alaska could trigger power outages in the region — much of the region's electricity is generated from ever-tightening supplies of natural gas from the region's aging gas fields. Many people see a ramp up of gas storage capacity in the region as a key means of alleviating the deliverability crunch: Storage facilities can hold excess gas produced during the summer and then make that gas available during periods of high gas demand in the winter.

Gas producers Marathon and Chevron already operate gas storage in the Cook Inlet basin, but the producers operate these facilities for their own use, to support their gas supply contracts. Aurora anticipates offering its facility for third-party use, perhaps for example by local utilities that want to store summer purchased gas for winter use.

Semco Energy, the parent company of gas utility Enstar Natural Gas Co., is fast tracking the development on the Kenai Peninsula of another third-party storage facility, but Pfoff feels confident that there's more than enough storage demand to support multiple facilities.

STEVE SUTHERLIN

The Nicolai Creek No. 2 well.

"We're not concerned that our project's going to get shut out," Pfoff said.

Still producing

Aurora's Nicolai Creek field still actively produces gas. However, in typical Cook Inlet fashion, the field contains several distinct reservoirs in various sand bodies. Aurora wants to use a relatively depleted reservoir in three upper Tyonek sands for storage, while also continuing to produce new gas from other reservoirs in the field.

With a total capacity of about 1 billion cubic feet, the storage facility would be quite modest in size and would likely be most useful in supporting peak demand on especially cold days, when short bursts of high gas flow are needed. This would likely fill a different niche in the gas storage market than the Semco facility, which appears to target a more seasonal-scale demand level, Pfoff said.

Operation of the facility would start by using a single, existing well, the Nicolai Creek No. 2. This particular well penetrates the reservoir steeply. So, in a second phase of facility development Aurora plans to drill a horizontal well in the reservoir, to boost the rate at which gas could be both injected into the reservoir and retrieved from it — a horizontal well would be in direct contact with a much larger volume of the reservoir than a steeply inclined well.

Aurora expects phase one of the storage development to go into operation in 2011. However, completing phase two of the project in that same year would be very challenging, Pfoff said.

Open season

In August 2009 Aurora conducted an open season for the facility, to determine the level of commercial interest. The company offered the possibility of 800 million cubic feet of firm storage.

"We had one strong expression of interest," Pfoff said.

But Aurora cannot negotiate specific terms and conditions with its prospective customer until the DNR lease is finalized. Negotiations with DNR had become stuck over lease terms that would have allowed DNR to determine how Aurora would charge for the storage services, Pfoff said. However, with DNR now having backed off that requirement, discussions are moving ahead again, focusing on determining an appropriate lease rental for the facility, he said.

On July 27 AOGCC issued its certification of the Nicolai Creek storage reservoir, thus enabling Aurora to claim the tax credit incentives available under the state gas storage legislation enacted this year — Pfoff had explained why Aurora had applied for this certification.

"We had to certify that the reservoir was a certain size so that it could qualify for some of the incentives that were being offered," he said.

AOGCC has certified that the storage facility has a capacity of 700 million cubic feet, with a minimum gas withdrawal rate of 10 million cubic feet per day.

Regulatory clarity

Aurora will also need clarity over potential regulation of the Nicolai Creek facility by the Regulatory Commission of Alaska: The company plans to talk to the commission about this issue, Pfoff said.

"I think there's still a little bit of uncertainty out there as to whether or not we would be a regulated facility," Pfoff said. "We would want to resolve that and work with them."

And Pfoff confirmed that Aurora does plan to make the storage facility available for use by third-party customers.

"Everybody agrees that we need storage and I think the mindset is 'what do we need to do to make it happen?'" Pfoff said. "… We're just very appreciative of the legislative efforts to provide incentives for us to do storage and exploration and development in the Cook Inlet. Now it's on us to run with it and make it happen."

—ALAN BAILEY

Contact Alan Bailey at abailey@petroleumnews.com