Petroleum news

page 12 State looks at shale development issues; conventional impediments

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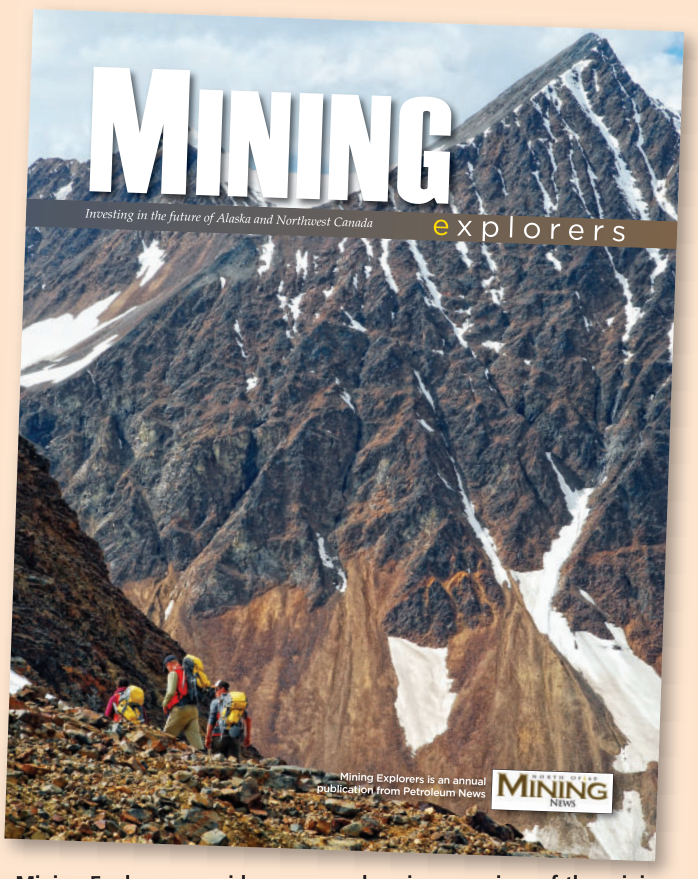
2011 Mining Explorers inside



Mining Explorers provides a comprehensive overview of the mining companies investing the capital and time needed to unlock the enormous mineral potential of Alaska and northern Canada.

CIRI drilling confirms coal seams suitable for UCG; seismic planned

Schutt said that the Stone Horn Ridge joint venture has found multiple, thick coal seams at depths below 650 feet in the Stone Horn Ridge area.

After an exploration program involving the drilling of 13 core holes, Cook Inlet Region Inc. has confirmed the existence of a significant coal resource likely to be suitable for underground gasification in the corporation's land on the west side of Alaska's Cook Inlet.

"We've done a significant amount of exploration work," Ethan Schutt, CIRI senior vice president for land and energy development, told the Alaska Senate Resources Committee on Oct. 20. "Through that work we've confirmed that we have a significant commercial coal resource in a geological setting that is favorable for UCG (underground coal gasification) develop-

see **CIRI COAL** *page 18*

Canada tells US it will export 'elsewhere' if its oil not wanted

The battle over TransCanada's Keystone XL pipeline has shifted from shadowboxing to a bare-knuckles contest in Canada.

Federal Natural Resources Minister Joe Oliver has sent a blunt message to Obama administration officials telling them that "if they don't want our oil, it is obvious we are going to export it elsewhere."

By way of stirring the pot, he said that as part of a "broad strategic objective" Canada must diversify its markets and China "has emerged as the largest customer of energy in the world, so it is utterly obvious what we must do. They are hungry for our (mineral and petroleum) resources."

However, Oliver did not specifically endorse Enbridge's Northern Gateway proposal, which is designed to export 525,000 barrels per day of oil sands crude to the Asia-Pacific

see **KEYSTONE DEBATE** *page 15*

PIPELINES & DOWNSTREAM

Pump station plumbing

Alyeska to spend millions to reconfigure piping as safeguard against corrosion

By WESLEY LOY
For Petroleum News

The operator of the trans-Alaska oil pipeline is embarking on an expensive, three-year program to replace piping in several pump stations.

The work stems from a settlement Alyeska Pipeline Service Co. reached with federal regulators following a corrosion-caused oil spill in January at Pump Station 1 on the North Slope. The leak forced a lengthy shutdown of the pipeline.

Alyeska has told the U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration it has completed a risk assessment of pump station piping that's subject to corrosion and difficult to inspect. It was piping of this sort that leaked at Pump Station 1.

Pump Station 1 will see "the most complex and critical" project, Alyeska says. It will be the first station to have its below-ground crude oil piping rerouted to an above-ground configuration.

As a result of the assessment, Alyeska is designing plans for work at pump stations 1, 3, 4, 5 and 9.

"These designs will replace buried non-inspectable crude oil piping with piping in an above ground alignment," says a summary document Alyeska provided at the request of Petroleum News.

see **ALYESKA PIPING** *page 15*

EXPLORATION & PRODUCTION

Halliburton in the game

2nd largest oilfield service firm partners with Great Bear on Alaska shale

By KAY CASHMAN
Petroleum News

Skeptics beware. If you thought Great Bear Petroleum's plan to drill 200 wells per year in its North Slope shale acreage was unrealistic, the world's second largest oilfield service company thinks you're wrong.

Halliburton, an expert in extracting oil and gas from source rock in major resource plays outside Alaska, has partnered with Great Bear. In the next year Halliburton will be conducting a parallel "proof of concept" multi-well program on Great Bear's acreage along the Dalton Highway — at the same time Great Bear is executing a similar program to the south, along the highway. In the next year, each company plans to drill as many as three vertical wells and a lateral off of each of those.

"We are partnering with Halliburton on an area-limited basis where they are bringing in world-class technology," Great Bear President and COO Ed Duncan told a special meeting of the Alaska Legislature's House Resources Committee Nov. 1. (Go online to http://bit.ly/rtkXIZ for eight slides used by Duncan in his presentation.)

A PN source at Halliburton said the giant oilfield service company is covering all of the costs of its proof of concept program, except permitting, including the cost of actually drilling wells, which will likely be outsourced to a rig contractor.

see **ALASKA SHALE** *page 19*

LAND & LEASING

Four new units for BRPC

State divides 2 unit proposals into 4 with drilling commitments through 2014

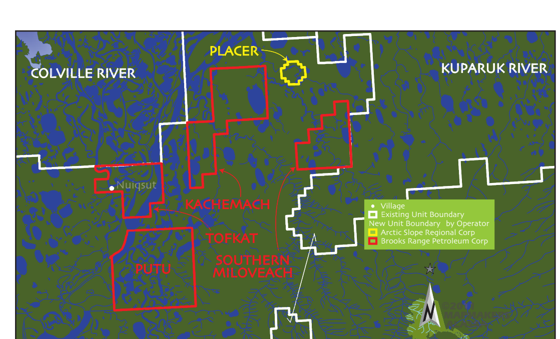
By ERIC LIDJI
For Petroleum News

Over the past year, Brooks Range Petroleum Corp. applied to form two units in the central North Slope fairway between the Colville River and Kuparuk River units.

Instead, it got four, with much less total acreage.

In separate decisions in late October, the Alaska Department of Natural Resources divided the proposed Putu unit into the smaller Tofkat and Putu units, and the proposed Southern Miluveach unit into the smaller Southern Miluveach and Kachemach units.

With the decisions, BRPC must now drill as many as 11 wells and sidetracks, and decide whether to sanction two development projects at the four units by mid-2014.



BRPC is the local operating arm of Kansas-based independent Alaska Venture Capital Group LLC and the operator of a multi-company joint venture that

see **BRPC UNITS** *page 17*

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 Z-65	BP
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay S-09/OH	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD4-03	ConocoPhillips
AC Mobile	25	Prudhoe Bay 04-350	BP
OIME 2000	141 (SCR/TD)	Kuparuk 2A-11	ConocoPhillips
TSM 7000	Arctic Wolf #2	In Nisku, AB	Available
Kuukpik	5	Drilling Savik #2	North Slope Borough
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 2K-22A	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay Stacked out	Available
Mid-Continental U36A	3-S	Prudhoe Bay Stacked out	Available
Oilwell 700 E	4-ES (SCR)	Prudhoe Bay X-22A	BP
Emsco Electro-hoist	7-E (SCR-TD)	Prudhoe Bay DS12-27A	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay R14-B	BP
Dreco 1000 UE	9-ES (SCR/TD)	Has been released by Brooks Range Petroleum	Available
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay Stacked out	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay Stacked out	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)	Stacked at Deadhorse, will go to Oooguruk for exploration drilling in January	Pioneer
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Oliktok Point OP10-09	ENI

*Nabors 27-E will be under contract at Oooguruk/Nuna for Pioneer this winter

Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site R-03B1	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site 18-03C	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2A-07	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay final construction and commission	BP
NOV ADS-10SD	273	Prudhoe Bay final construction and commissioning	BP

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-26I	Pioneer Natural Resources
Oilwell 2000	33-E	Prudhoe Bay Stacked out	Available
Doyon Drilling			
Sky Top Brewster NE-12	15 (SCR/TD)	Spy Island SP18-N5	ENI

Cook Inlet Basin – Onshore

Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Rigging down from Three Mile Creek 3, will stack out south of Tyonek	Aurora Gas
Cook Inlet Energy			
Atlas Copco RD20 34		Undergoing winterization at W. McArthur River Unit	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Beluga, Stacked	Repsol
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Kenai Loop #3	Buccaneer Alaska
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked	Available
Academy AC electric Canrig	105-E (SCR-TD)	Kenai CLU-2	CINGSA
Rigmaster 850	129	Kenai Stacked out	Available

Cook Inlet Basin – Offshore

Chevron (Nabors Alaska Drilling labor contract)			
	428	M-11 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
Spartan Drilling			
Baker Marine ILC-Skidoff, jack-up		Spartan 151 Upper Cook Inlet KLU#1	Escopeta

Mackenzie Rig Status

Canadian Beaufort Sea

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

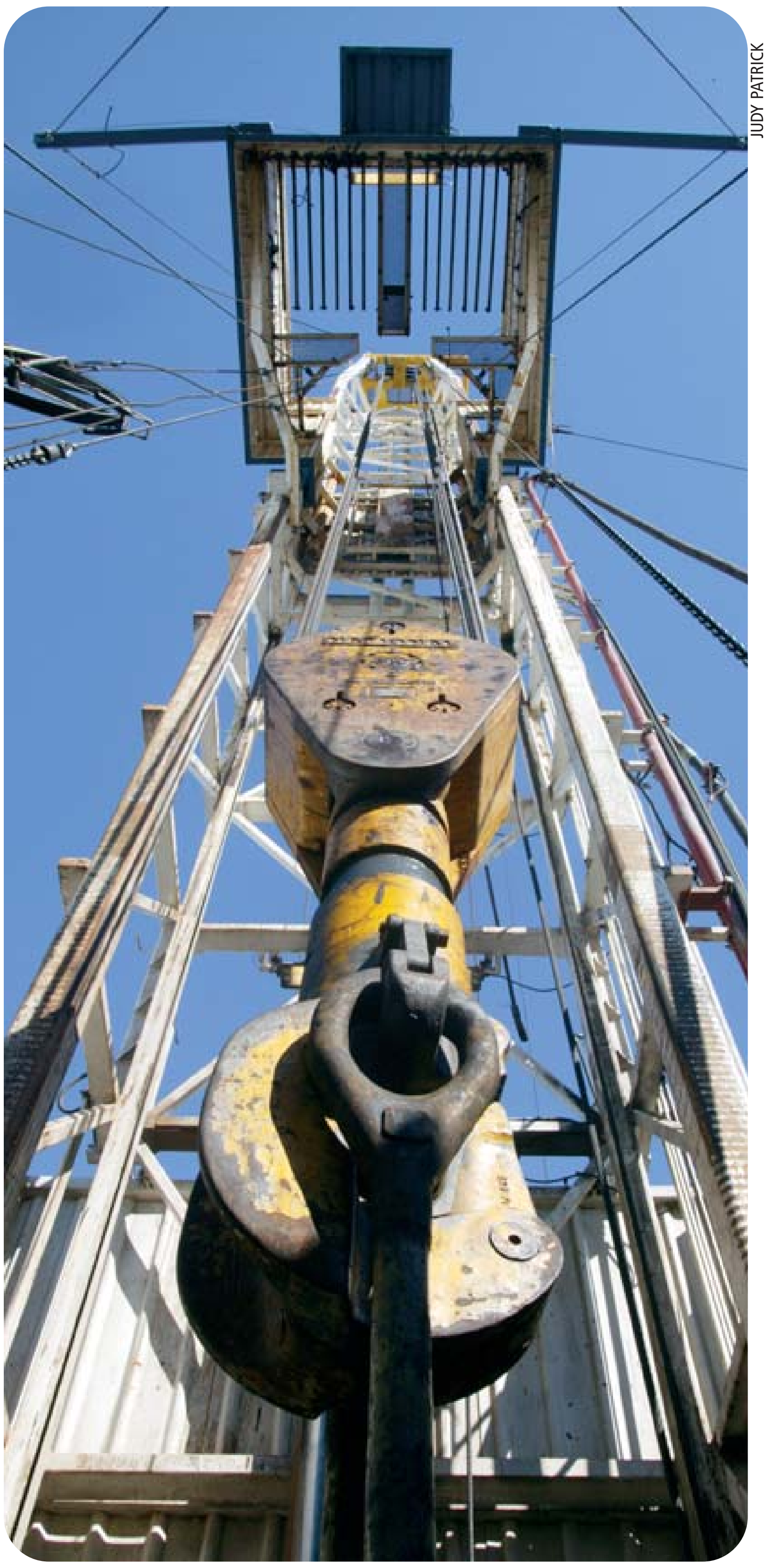
Central Mackenzie Valley

Akita/SAHTU			
Oilwell 500	51	Has left the NWT	Available

The Alaska - Mackenzie Rig Report as of November 3, 2011. 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*

	October 28	October 21	Year Ago
US	2,021	2,013	1,672
Canada	499	497	433
Gulf	33	33	22

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

The Alaska - Mackenzie Rig Report is sponsored by:

ARMSTRONG

● GOVERNMENT

Parnell meets with top BP execs in London

Shell, Eni CEOs next on European trip; main topics with BP were gas pipeline and Asia market, oil tax cuts, infrastructure integrity

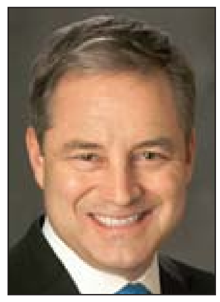
By KAY CASHMAN

Petroleum News

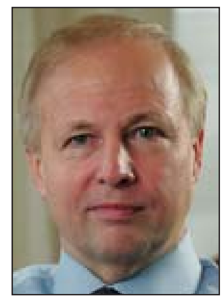
Gov. Sean Parnell told Petroleum News in a phone interview from London that he had a lengthy meeting on Nov. 2 with BP Chief Executive Bob Dudley, their conversation centering on three major issues of concern to the governor — getting a natural gas pipeline from the North Slope built soon, how Alaskans might benefit if oil taxes are cut, and the integrity of North Slope infrastructure.

Also attending the meeting were BP Exploration Alaska President John Minge and Bob Fryar, the executive vice president on BP's senior management team who is responsible for safe and compliant BP exploration and production operations and the stewardship of resources, including natural gas, around the world.

On a natural gas pipeline, Parnell said he thought it important to repeat what he had said in an Oct. 27 speech at the Alaska Oil and Gas Association luncheon in Anchorage, which was that if the best long-term gas market had truly shifted from the Lower 48 to Asia, he wanted the major holders of proven North Slope natural gas reserves — ExxonMobil, ConocoPhillips and BP — to consider liquefied natural gas exports to Asia.



GOV. SEAN PARNELL



BOB DUDLEY

TransCanada, the licensee with the state of Alaska under the Alaska Gasline Inducement Act, has always said it will be the gas producers who decide on the route of the gas pipeline.

Parnell also wanted to "signal that I am flexible about how to commercialize Alaska gas as long as it is in Alaska's interest … and that I want to see BP get better aligned with our licensee on the project."

The governor said a face-to-face meeting with BP's top executive was very important.

"I wanted to speak directly with Dudley. I wanted to be sure he knew what Alaska's concerns were and that I was also willing to work to bring investment to Alaska."

Parnell told The Associated Press that he left the meeting believing the two held a similar view that the region's market was worth investigating.

TransCanada is working with ExxonMobil to advance a natural gas pipeline project but it has not yet announced any agreements with shippers.

On Nov. 2, the president and chief executive of TransCanada, Russell K. Girling, said in a quarterly financial conference call that the continued focus of the Alaska Pipeline Project remains the Lower 48. But he said it is a market-driven project, "and we'll move the gas to wherever the market decides it wants to move the gas to."

A BP spokesman in Alaska, Steve Rinehart, said the company has studied and will continue to study the potential for liquefied natural gas. He said the goal is getting North Slope gas to market.

Parnell is in the midst of his first state-sponsored trip overseas, what he's calling an "investment mission." It is the latest in a series of trips that Parnell or other members of his administration have taken in an effort to tout Alaska's development and investment potential.

Parnell still plans to meet with the CEOs of two other energy firms, Royal Dutch Shell, Europe's largest oil company, and Eni SpA.

He began his trip in the United Kingdom, where in addition to meeting with Dudley, he also promoted one of the state's top exports, seafood.

Parnell said he was "professionally and graciously" received by Dudley, who Parnell said he also pressed to be more specific on what kind of benefits Alaskans could see if oil production taxes were cut.

Minge said earlier this year that he supported the $5 billion investments that a ConocoPhillips executive envisioned would occur if Alaska's oil production tax regime were changed, and said he saw that as a start "in terms of what is possible."

Minge's comments came as Parnell's tax cut bill stalled in the Senate, with leading lawmakers saying they didn't have the information they needed to make a sound policy call and some seeking firm commitments from energy companies for what Alaska would see in return if taxes were cut.

"I think that number they put out there, the $5 billion number, of new investment or additional investment, I think that's a bare minimum from one company," Parnell said.

While other companies would benefit from tax changes, too, "I'm in this to assure that Alaskans see more investment and see more jobs."

Parnell plans to revive the tax issue when the Legislature convenes in January. ●

—Becky Bohrer of the Associated Press contributed to this article.

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EXPLORATION & PRODUCTION

Escopeta, North Slope exploration updates

In early October there were more wells planned for the upcoming North Slope exploration season than ever before — 34, as compared to a record 33 drilled in 1969.

But by the end of October, some drilling plans were in jeopardy. Following are the companies that planned to drill between November of 2011 and November 2012, the maximum number of wells they were looking at, and the status of their programs:

- Brooks Range: 1 rig, 2 wells/on schedule.
- Great Bear: 1 rig, 12 wells, including six laterals/on schedule but could face a few months delay due to rig availability and final permits.
- Linc (Renaissance Umiat): 1 rig, 5 wells/company said Oct. 31, "Rigs are tight but we are making headway."
- Pioneer: 1 rig, 2 wells/on schedule.
- Repsol: 5 rigs, 15 wells/on schedule but there's a chance permitting challenges could delay part of the program until next winter.
- Savant: 1 rig, 1 well/subject to rig availability, likely will be delayed until next winter.
- UltraStar: 1 rig, 1 well/subject to rig availability, likely will be delayed until next winter.

In Southcentral Alaska's Cook Inlet basin, as of Oct. 31, Escopeta Oil had drilled down to 8,800 feet, a little over half the distance to the targeted depth for its first well in the offshore Kitchen Lights unit. The company was preparing to conduct its weekly blowout preventer test, followed by wireline testing.

On Nov. 3, Escopeta officials would not say if drilling would continue once testing was complete, despite the fact the Department of Environmental Conservation gave Escopeta permission to continue drilling until Nov. 15, weather and ice conditions permitting, and that both conditions were still favorable.

—KAY CASHMAN

● LAND & LEASING

Upbeat in the upstream

Canadian land auctions, horizontal drilling, lead the way to C$3.41B in exploration bids, 13,400 new well permits; optimism for 2012

By GARY PARK

For Petroleum News

Canadian governments, pulled along by a soaring producer appetite for oil and liquids prospects, raised C$3.41 billion from land sales in the first nine months of 2011, the third highest return in the last decade.

That rush to secure exploration rights, which fattened provincial coffers by C$3.04 billion in the same period of last year, is now reflected in upstream activity, with operators securing 13,440 new well permits in the January-September period this year, up 16 percent from 2010.

Those upbeat numbers have been reinforced by a decisive swing to horizontal drilling, with 6,973 of this year's licenses using a technology that made a quiet debut in 1988 with 16 wells.

The nine-month count this year has toppled the 12-month record of 6,668 horizontal wells set last year as producers embrace a technology that enables them to exploit Western Canada's less permeable reservoirs by using multistage fracturing on well laterals.

Permits obtained to the end of the third quarter included 8,820 oil and bitumen prospects, setting a 10-year high and 46 percent above last year's count for the same period.

Natural gas permitting posted a low for the last decade of 2,531 wells, off 31 percent from last year and a far cry from the January-September record of 14,837 wells set during a period of peak gas prices in 2005.

The permit count also included 1,113 oil sands evaluation wells, 228 ahead of the same period last year.

PSAC: No sign of tapering off

Mark Salkeld, president of the Petroleum Services Association of Canada, said the pace of drilling shows no signs of tapering off, with all equipment either working or booked to work and new rigs being manufactured to better handle deeper horizontal wells and lateral sections.

He said PSAC, which has forecast that rigs will be released on 13,325 wells this year, an increase of 10 percent over the 2010 total, is developing a "good degree of optimism" about 2012 as operators turn their attention to liquids-rich gas.

Salkeld said that although the number of rigs released will remain below pre-recession levels, the service sector benefits from the additional time needed to drill and complete horizontal wells.

Canadian National leads

Among the operators, Canadian Natural Resources leads in all categories, obtaining 1,181 well licenses, completing 939 wells in the first three quarters and drilling 1.06 million meters of hole.

Husky Energy obtained 897 well licenses and rig-released 799 wells, followed by Canada's biggest gas producer Encana at 659 permits and 510 rig releases, while oil sands producer Cenovus Energy received 466 permits and released 401 rigs.

Government agencies report that operators released rigs on 9,181 wells over the first nine months, up 14 percent from the same period of 2010, with about 70 percent listed as oil or bitumen wells.

Alberta increased its permit count 9 percent to 5,816 wells, with 3,767 targeting oil or bitumen, compared with 2,607 in first three quarters of last year.

Saskatchewan posted a 38 percent increase to 2,536 permits, with gas limited to 31 wells, while gas-weighted British Columbia declined to 466 wells from 517 and Manitoba was down 4 percent at 341 wells.

The land sales revenues to the end of September trailed the C$4.12 billion that was raised in 2008 and C$3.71 billion in 2006, years that were dominated by a scramble to secure oil sands rights in Alberta and shale gas prospects in British Columbia.

The average price so far this year is C$847 per hectare, compared with C$873 in the same period of 2010 and is the third highest on record, while the amount of land sold increase 15 percent from last year to 4.02 million hectares (9.93 million acres).

Alberta outpaces other provinces

Alberta easily outpaced the other provinces, pocketing C$3.06 billion from 3.46 million hectares at a per-hectare average of C$884, a record at the three-quarter point.

Northern Alberta, where companies are gearing up to probe the region's shale gas prospects, attracted the bulk of spending at C$2.66 billion, double last year.

British Columbia continued its nosedive, with successful bids sliding to C$123 million at an average C$1.016 per hectare, compared with C$780 million at an average C$2.329 per hectare for the same period last year.

Saskatchewan raised C$214.9 million from its auctions, down from C$371.6 million last year, but the total land involved rose to 420,746 hectares from 316,506 hectares.

In addition to cash bonus payments, producers acquired rights through work commitments to 363,681 hectares in the Northwest Territories. ●

Contact Gary Park through publisher@petroleumnews.com

E&P

Pioneer production drops in third quarter

Pioneer Natural Resources Alaska Inc. produced 4,000 net barrels of oil equivalent per day during the third quarter, down from 7,000 net boe per day in the same period in 2010.

The Texas-based independent produced 128,000 net boe per day across all its properties during the quarter, up from 104,000 net boe per day during the same period last year, an increase largely attributable to increasing Eagle Ford Shale and Permian Basin production.

Pioneer operates the Oooguruk unit in the nearshore waters of the Beaufort Sea.

The company is planning two "key wells" this winter, a "deep test" in the Ivishak and a fracture stimulation operation in the Torok formation, according to CEO Scott Sheffield.

Sheffield said the company would have results no earlier than May.

—ERIC LIDJI

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Beaufort Sea Areawide	Dec. 7, 2011
DNR	North Slope Areawide	Dec. 7, 2011
DNR	North Slope Foothills Areawide	Dec. 7, 2011
BLM	NPR-A	Dec. 7, 2011
DNR	Cook Inlet Areawide	spring 2012
DNR	Alaska Peninsula Areawide	spring 2012
DNR	Beaufort Sea Areawide	fall 2012
DNR	North Slope Areawide	fall 2012
DNR	North Slope Foothills Areawide	fall 2012
BLM	NPR-A	2012

Agency key: BLM, U.S. Department of the Interior's Bureau of Land Management, manages leasing in the National Petroleum Reserve-Alaska; BOEMRE, U.S. Department of the Interior's Bureau of Ocean Energy Management, Regulation and Enforcement (formerly Minerals Management Service), Alaska region outer continental shelf office, manages sales in federal waters offshore Alaska; DNR, Alaska Department of Natural Resources, Division of Oil and Gas, manages state oil and gas lease sales onshore and in state waters; MHT, Alaska Mental Health Trust Land Office, manages sales on trust lands.

● EXPLORATION & PRODUCTION

October Alaska North Slope production down 3 percent

By KRISTEN NELSON

Petroleum News

Alaska North Slope production for October was down 3.4 percent from September, averaging 588,287 barrels per day compared to 608,680 bpd in September.

With the exception of the BP Exploration (Alaska)-operated Northstar field, all other North Slope fields had month-over-month decreases in production.

Except where noted, volumes are from the Alaska Department of Revenue's Tax Division, which tracks oil production by major production centers and provides daily production and monthly averages.

The largest percent decrease, 15.6 percent, was at BP's Milne Point field, which averaged 18,826 bpd in October, down from 22,312 bpd in September, a difference of 3,486 bpd.

The largest barrel difference was at the BP-operated Prudhoe Bay field, which averaged 293,643 bpd in October, down 4.3 percent, 13,053 bpd, from a September average of 306,696 bpd.

Prudhoe Bay includes satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris. The most recent data by field and pool from the Alaska Oil and Gas Conservation Commission is for August. In that month, Prudhoe Bay itself produced 5,863,649 barrels. The satellite with the largest production was Borealis at 349,510 barrels, followed by Aurora at 266,807 barrels, Orion at 256,508 barrels, Polaris at 162,582 barrels and Midnight Sun at 45,303 barrels.

Kuparuk River

The smallest production drop was at the ConocoPhillips Alaska-operated Kuparuk River field, which averaged 137,657 bpd in October, down 0.2 percent, just 311 barrels, from a September average of 137,968 bpd.

Kuparuk includes production from satellites at Meltwater, Tabasco and Tarn, as well as West Sak viscous oil production, and production from the Eni-operated Nikaitchuq field and the Pioneer Natural Resources Alaska-operated Oooguruk field. AOGCC figures for August show the majority of Kuparuk oil is from the main reservoir, 2,826,328 barrels, with West Sak coming in second at 489,228 barrels, followed by Tarn at 320,743 barrels, Meltwater at 86,187 barrels and Tabasco at 49,888 barrels.

August production from Nikaitchuq was 196,442 barrels, some 6,337 bpd; August Oooguruk production was 186,161 barrels, some 6,005 bpd.

Colville River

Alpine, operated by ConocoPhillips Alaska, averaged 82,194 bpd in October, down 1.6 percent, some 1,315 bpd, from a September average of 83,509 bpd.

The Alpine field is the main producer at the Colville River unit, the farthest west production on the North Slope, but the unit also has production from the Fiord, Nanuq and Qannik satellite fields. AOGCC figures for August show Alpine accounting for some 71 percent of production, followed by Fiord at 26 percent, Qannik at 2 percent and Nanuq at 1 percent.

The BP-operated Lisburne field averaged 31,041 bpd in October, down 6.6 percent from a September average of 33,250 bpd. Lisburne includes production from the Point McIntyre and Niakuk fields.

The BP-operated Endicott field averaged 11,893 bpd in October, down 3.8 percent, some 466 barrels, from a September average of 12,359 bpd. Endicott includes production from Badami, which according to AOGCC figures for August, averaged 1,143 bpd in that month.

The BP-operated Northstar field, the only North Slope field with increased production October-over-September, averaged 13,033 bpd in October, up 3.6 percent, 447 bpd, from a September average of 12,586 bpd.

Cook Inlet

The temperature at Pump Station 1 on the North Slope averaged 26.3 degrees F in October, compared to an average of 38.8 F in September.

Cook Inlet production averaged 10,641 bpd in October, down 18.9 percent, some 2,485 bpd, from a September average of 13,126 bpd.

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

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● LAND & LEASING

State, BLM lease sales set for Dec. 7

Oil & gas lease sales cover adjacent areas in state, National Petroleum Reserve-Alaska; 14.7 million state acres, 3 million federal

By KRISTEN NELSON

Petroleum News

In September the Alaska Department of Natural Resources delayed the state's fall areawide oil and gas lease sales from Oct. 26 to Dec. 7 to allow potential bidders more time to do due diligence and to allow the state the opportunity to add acreage from expired leases.

SHANE LASLEY

DAN SULLIVAN

The Bureau of Land Management was already planning a lease sale in the National Petroleum Reserve-Alaska and said Oct. 28 that its NPR-A oil and gas would be held the same day as the state's sale.

The state Division of Oil and Gas will open bids beginning at 9 a.m. on Dec. 7 in the Dena'ina Civic and Convention Center in Anchorage. Bids for BLM's NPR-A sale will be opened at 1 p.m. in the Denali Room at the Anchorage Federal Building.

DNR called it "a rare opportunity" for investors "to bid on the same day for adjacent state and federal oil and gas leases on the North Slope."

The department said its North Slope and North Slope Foothills sales include tracts adjacent to federal tracts available at the BLM lease sale, giving a bidder the potential to pick up adjacent acreage on state and federal lands, thus gaining more flexibility in accessing oil and gas pools.

"This should greatly improve a company's ability to explore and develop both state and federal acreage," DNR Commissioner Dan Sullivan said in an Oct. 28 statement. He said the state has been coordinating with the federal government on the lease sale dates "in the hope that working together will enhance opportunities for successful state and federal oil and gas lease sales."

Two known prospects

DNR cited two known prospects, Umiat and Gubik, which straddle state land and NPR-A, but said "much of the acreage along the state-federal border has seen minimal exploration in recent years," and said it is offering those lands at minimum royalty rates and rental rates to entice interest.

DNR noted that according to a 2005 U.S. Geological Survey assessment there are 19 oil plays straddling state and NPR-A acreage, 17 of which are included in the BLM sale area.

The state's lease sale includes nearly 15 million acres.

While BLM is offering selected tracts, the state is offering unleased acreage in its sales areas under its areawide leasing program.

BLM sale area

BLM is offering tracts 283 tracts, some 3 million acres, in Northeast and Northwest NPR-A, including 178 tracts, 1.8 million acres, in Northeast NPR-A and 105 tracts, 1.2 million acres, in Northwest NPR-A.

BUD CRIBLEY

BLM said in an Oct. 28 statement that there are currently 169 oil and gas leases in NPR-A totaling 1,361,105 acres in the Northeast and Northwest planning areas of NPR-A.

BLM-Alaska State Director Bud Cribley called NPR-A energy resources "essential to meeting our nation's energy demands" and said those resources would "enhance domestic energy production and decrease dependency on foreign oil sources."

"I believe it is possible to develop oil and gas resources, while protecting important surface and subsistence resources," Cribley said in BLM's Oct. 28 release. He said the oil and gas lease sale reflects BLM's "mission to balance the protection of the natural resources and rural subsistence with the nation's need for oil and gas development within the NPR-A." ●

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● FINANCE & ECONOMY

Courts give Rutter Umiat prospect royalty

Alaska Supreme Court affirms lower court ruling on small overriding royalty interest at the North Slope oil prospect

By ERIC LIDJI

For Petroleum News

Affirming a lower court ruling, the Alaska Supreme Court is allowing a Texas-based independent to keep an overriding royalty interest in a North Slope oil prospect.

The Oct. 28 ruling allows Rutter and Wilbanks Corp. to retain half of a 3.75 percent overriding royalty that it and former partner Renaissance Alaska LLC kept on the leases they held in the Umiat area under a joint venture called Renaissance Umiat LLC.

While the interest is small, it could be valuable.

Earlier this year Australian independent Linc Energy Ltd. acquired Renaissance Alaska, giving it 100 percent working interest and 80 percent net revenue interest in the Umiat oil field in the foothills of the Brooks Range Mountains, straddling the Colville River.

Linc plans to begin exploring the prospect this winter and previously estimated that its stake in the prospect could yield more than 200 million barrels of oil equivalent.

The case concerns lease documents for the prospect.

Renaissance Alaska and Rutter and Wilbanks began considering a partnership at the Umiat oil field in 2004 and 2005. As the companies moved forward on the project, they kept all lease documents in Renaissance's name alone to simplify federal paperwork.

After purchasing leases at Umiat, the companies sought an additional lease in the area owned by Arctic Falcon Exploration LLC. The three companies eventually formed Renaissance Umiat in early 2007. While the negotiations involved in creating that joint venture set the stage for the current lawsuit, Arctic Falcon is not a party in the case.

When the companies joined together, Arctic Falcon insisted on retaining an overriding royalty interest on its lease. Renaissance's Mark Landt told the courts, "Our position was, if he's going to retain an override, then we're going to retain an override," and as a result, Renaissance Alaska decided to keep a 3.75 overriding royalty interest in its Umiat leases.

The operating agreement between Renaissance and Rutter and Wilbanks required the two companies share development costs at Umiat up to $25 million, or forfeit their interest.

As Renaissance began developing the prospect, it asked Rutter and Wilbanks for its share of the money. When it didn't pay, Rutter and Wilbanks forfeited its interest in Umiat.

In August 2008, Rutter and Wilbanks claimed in court that it was entitled to half of the 3.75 percent overriding royalty interest and the Superior Court ultimately agreed.

Although the companies never made any agreement about the overriding royalty, Renaissance said it should be allowed to keep the entire 3.75 percent for two reasons.

First, Renaissance argued that it held legal title to the overriding royalty, and that Rutter would need a court order to obtain a title. Second, it argued that the contract essentially implied Rutter would forfeit its share of the royalty by forfeiting its interest in the leases.

While Renaissance argued that it alone held legal title to the overriding royalty interest, the courts decided that the companies always intended to proceed as an equal partnership, and used only Renaissance's name on federal filings to simplify the paperwork process.

Concerning the idea that the contract implied forfeiture of the overriding royalty should one of the companies fail to pay its share of the operating expenses, the courts decided that "had Renaissance and Rutter wished to include an express term linking the (overriding royalty interest) to the minimum spending requirement, they could have done so." ●

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ASSOCIATIONS

Moriarty to replace Crockett at AOGA

Kara Moriarty, deputy director of the Alaska Oil and Gas Association, has been named to replace Marilyn Crockett as the association's executive director.

AOGA said in a Nov. 1 release that its board of directors unanimously named Moriarty to replace Crockett, who is retiring from AOGA effective Jan. 1 after more than 41 years with the association.


DAVE HARBOUR PHOTOGRAPHY
KARA MORIARTY

"Marilyn Crockett has spent her entire professional career dedicating herself and her strong work ethic to AOGA and has earned the right to enjoy retirement after so many years of service to our industry," Dale Pittman, Alaska production manager for ExxonMobil and current president of AOGA, said in a statement.

"At the same time, I want to say how pleased we are that after an extensive nationwide search, we found our next leader right here at home in Kara Moriarty. She has the talent, competence and ability to lead AOGA in the days ahead as our industry faces many new challenges and opportunities, especially with declining oil production."

Moriarty at AOGA since 2005

Moriarty started her career in 1996 as a teacher in the small Inupiat village of Atqasuk on the North Slope, and since then has held various policy positions in both the public and private sectors. She worked for a U.S. congressman in Washington, D.C., and served as legislative staff in Juneau.

Moriarty said she looked "forward to building onto our strong team to foster the long-term viability of the most important private sector industry in Alaska. It is a great honor and I look forward to the opportunity."

Prior to coming to AOGA, she was the president and chief executive officer of the Greater Fairbanks Chamber of Commerce for four years.

She joined AOGA in 2005 as a program associate and served as external affairs manager before becoming deputy director in 2007.

"I can think of no single individual who is better positioned than Kara to take over the reigns as AOGA's executive director," Crockett said. "She has strong connections throughout the state and is highly respected."

Moriarty said she looked "forward to building onto our strong team to foster the long-term viability of the most important private sector industry in Alaska. It is a great honor and I look forward to the opportunity."

Moriarty will be the fifth executive director in the association's 45-year history.

—PETROLEUM NEWS

● NATURAL GAS

Gas line player Yukon Pacific winds down

Company surrenders federal right-of-way grant for its LNG project; despite $100M investment, construction never started

By WESLEY LOY
For Petroleum News

A longtime contender for construction of an Alaska natural gas pipeline is bowing out of the game.

Yukon Pacific Corp., in correspondence with federal officials, said its Trans-Alaska Gas System project, or TAGS, "has officially come to a close," and the company is in the process of dissolution and winding down its business affairs.

Efforts related to TAGS "reflect an investment in Alaska of more than $100 million with no return," said a June 2 letter from an Anchorage law firm representing Yukon Pacific.

The letter was in support of the company's request to surrender its federal right-of-way grant for the TAGS project, construction of which never got under way.

The U.S. Bureau of Land Management on Oct. 26 issued a decision honoring Yukon Pacific's request and terminating the right-of-way grant.

Yukon Pacific had held the grant since 1992, and was incurring expenses such as annual rent in keeping it.

Company's rise and fall

Yukon Pacific, whose major owner is transportation giant CSX Corp., was incorporated in Alaska in 1983. For many years, Wally Hickel, the late governor of Alaska, was involved with the company.

The company's aim was to build an 800-mile pipeline to carry the huge North Slope gas reserves to the city of Valdez for liquefaction and shipment aboard tankers to Asia.

But the enormous cost of building a gas line across Alaska frustrated Yukon Pacific's efforts.

The company suffered serious setbacks in recent years.

In 2008, the Alaska Department of Natural Resources took away the company's conditional pipeline right of way across state lands. The department held that Yukon Pacific had not shown enough progress for a renewal.

In April 2010, Yukon Pacific asked the Federal Energy Regulatory Commission for a three-year extension of the deadline to commence construction of its liquefied natural gas export terminal at Anderson Bay near Valdez. FERC's Office of Energy Projects denied the extension, saying a 1995 environmental impact statement for the project was outdated.

Yukon Pacific cleared out of its office space in downtown Anchorage in 2003.

Even with Yukon Pacific's departure, the idea of shipping LNG overseas is still part of Alaska's ongoing gas line discussion.

Indeed, on Oct. 27, Gov. Sean Parnell suggested energy companies come together on an LNG project, as efforts to build a pipeline to the Lower 48 seem to have stalled. ●

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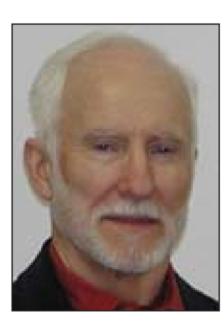
● UTILITIES

Keeping the Railbelt power flowing

Main Alaska population centers face challenges with electricity delivery amid tightening gas supplies and an aging infrastructure

By ALAN BAILEY
Petroleum News

The average shopper walking through an Anchorage mall probably takes for granted the flow of electrons that power shop lights, keep the heating system working and enable that quick cell phone call to home. But with many of those electrons originating from power stations burning a continuous flow of natural gas from the aging Cook Inlet gas fields, and with the electrons traveling from power stations to power demand centers through a fragile power transmission network, much of it built many decades ago, staff in the region's electric utilities worry about the reliability of those vital power supplies.


JOE GRIFFITH

Winter concern

On Oct. 20 Joe Griffith, president of the Alaska Railbelt Cooperative Transmission and Electric Co., otherwise known as ARCTEC, described to the Alaska Senate Resources Committee the steps that the utilities are taking to ensure power supply reliability.

The bulk of the power used in the Alaska Railbelt grid, stretching from Homer in the south, through Anchorage to Fairbanks in the north, comes from gas-fired power stations. But with most of the gas flowing from gas fields that are decades old, gas and power utilities have struggled in recent years to ensure an adequate flow of utility gas to meet peak winter demand. In the event of a serious gas shortfall, the power utilities would have to protect the pressure in gas distribution pipelines by instituting a series of rolling blackouts to reduce gas usage — the utilities have already worked out a plan for how to allocate the blackouts among themselves, Griffith said.

Griffith expressed particular concern about the coming winter, saying that the

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RAILBELT POWER

mothballing of a liquefied natural gas facility on the Kenai Peninsula will lead to less robust gas supplies during periods of peak winter demand, while a new gas storage facility being built on the peninsula by Cook Inlet Natural Gas Storage Alaska will not come on line until the spring of 2012.

"Every one of us believes that this will be the most difficult year to face," Griffith told the lawmakers.

Griffith said that, although there are proposals for delivering North Slope gas to Southcentral Alaska by pipeline, a pipeline cannot be built in time to solve the immediate gas shortage problem. New gas development in the Cook Inlet basin is the least expensive energy option and should be encouraged through appropriate incentives and rapid permitting, he said. However, the import of liquefied natural gas into Southcentral Alaska, to bolster local gas supplies, appears to be inevitable at some point, he said.

"Unfortunately I don't see any way of getting out of importing LNG," Griffith said.

Generation & transmission co-op

In December 2010 five of the six Railbelt electric utilities formed ARCTEC as a power generation and transmission cooperative to pool their resources, to achieve economies of scale for grid operations and to provide a vehicle for the funding of grid upgrades. Founding members were Chugach Electric Association, Matanuska Electric Association, Homer Electric Association, Seward Electric and Golden Valley Electric Association.

And the cooperative has what it terms the "Railbelt Energy Plan," derived from an earlier plan developed by the Alaska Energy Authority and designed to address a number of issues that the Alaska Railbelt power grid faces, Griffith explained.

Within the power generation components of this plan, Chugach Electric Association, in partnership with Anchorage utility Municipal Light & Power, is building the Southcentral Power Project, a state-of-the-art, high-efficiency gas-fired power station in Anchorage. At the same time, Matanuska Electric Association, or MEA, is pushing ahead with a plan to build a new power station at Eklutna, at the base of the Chugach Mountains to the north of Anchorage. MEA plans to run the Eklutna power station on natural gas but the plant will also be able to accept other fuels, thus enabling the use of diesel fuel or perhaps propane in the event of a gas shortage.

Hydropower

Hydropower, especially from the Bradley Lake power plant in the southern Kenai Peninsula, makes a significant contribution to the Railbelt power generation capacity. One component of the Railbelt Energy Plan is an upgrade to the Bradley Lake facility, adding 30,000 megawatt hours to the capacity of that plant through the diversion of an additional creek into the facility's water supply, Griffith said.

And, looking further into the future, the Alaska Energy Authority is moving ahead with a plan to build a major hydropower plant at Watana on the Susitna River, 125 miles or so upstream of the town of Talkeetna. ARCTEC supports this project and the Alaska Energy Authority has just asked the utilities for information about how much power they are likely to need from the plant, Griffith said.

From the perspective of wind power, Chugach Electric Association has recently agreed to buy power from Cook Inlet Region Inc.'s Fire Island wind farm, offshore Anchorage, with that wind power purchase agreement now before the Regulatory Commission of Alaska for approval. Matanuska Electric Association has also agreed to take 15 percent of the power from Fire Island but has yet to finalize a price agreement for the power — the price looks like being somewhere in the range $90 to $95 per megawatt hour, Griffith said.

Fairbanks utility Golden Valley Electric Association is in the process of building another wind farm at Eva Creek near Healy, on the north side of the Alaska Range.

And on another front, Ormat Technologies is proceeding with a geothermal power project on the flanks of Mount Spurr, an active volcano to the west of Anchorage.

$56 million

In the last legislative session, the Alaska Legislature appropriated $56 million for upgrades to the Railbelt power infrastructure, with much of that money going into upgrades of aging power transmission lines. One series of transmission interties connects Fairbanks to a coal-fired power station at Healy, and hence to the Matanuska and Susitna valleys and Anchorage. Another intertie system connects Bradley Lake with Nikiski and Quartz Creek on the Kenai Peninsula, with this system also connecting through to Anchorage.

Those are the highways that carry the power to our people, Griffith said.

"It's a weak system … but it's so important," he said.

Coordinating the operation of the complete transmission grid can be a major headache, with the potential for a major power outage if things go awry.

"The last big one we had in 1989 took five days to put … back together, so it's no small undertaking to coordinate that," Griffith said.

The utilities operate the transmission network under the terms of a joint Alaska intertie agreement. However, a new Intertie Management Committee is being formed to oversee intertie operations — this committee will replace the committee that used to operate the intertie north from the Matanuska and Susitna valleys, Griffith said.

"We think we will have that in place within 60 days," he said.

New requests

And ARCTEC anticipates a number of further intertie upgrades as part of a package of legislative requests that the cooperative is preparing for the upcoming legislative session.

Some of the current state funding is also going into work on the pipeline system that carries natural gas under Cook Inlet. The system, known as the Cook Inlet Gas Gathering System, is being modified to allow gas to flow east to west under the inlet, rather than just west to east as at present. Bidirectional flow in the line will enable greater flexibility in transporting gas to locations such as Chugach Electric Association's Beluga power station on the west side of the inlet.

Looking more broadly at energy issues along the Alaska Railbelt, Griffith commented on the difficult energy cost situation in Fairbanks, a city with limited access to natural gas supplies in the form of trucked-in LNG. The high cost of fuel oil for heating homes drives people to use firewood, a cheaper fuel option, while the burning of wood is leading to air quality problems. Energy cost issues in Fairbanks could place at risk some of the federal installations that are so important to the Alaska economy, Griffith said. ●

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● FINANCE & ECONOMY

Oil industry biggest source of AK jobs

Report finds that the industry directly and indirectly created 44,800 jobs and $2.65 billion in payroll for Alaska residents in 2010

By ALAN BAILEY
Petroleum News

The McDowell Group, in a report prepared for the Alaska Oil and Gas Association, or AOGA, has found that the oil and gas industry is directly and indirectly responsible for nearly 45,000 jobs for Alaska residents. That amounts to about 13 percent of all private sector jobs in Alaska and 10 percent of all employment in the state, the report says.

Proprietary data

Rather than using U.S. Department of Labor employment data, which categorizes employment in ways that only provide a partial view of the industry's impact, the McDowell Group relied heavily on detailed proprietary data from individual companies when preparing its report, Jim Calvin, a managing principal in the McDowell group, told people attending AOGA's annual lunch on Oct. 27.

By thus gaining insights into where companies spend money and what they spend the money on, it is possible to develop a model of how the oil industry money moves through the Alaska economy, creating the financial multiplier effect of a cascading chain of company and employee spending, Calvin explained.

Looking at data for 2010, the McDowell Group analysts assessed the employment of Alaska residents in terms of employment by "primary companies" and employment by oil industry service companies. The analysts then proceed to assess what they referred to as "induced employment," jobs that result from spending by the employees of primary and service companies and from spending by the service companies themselves.

Primary companies, at the front end of the oil industry cash flow, consist of oil and gas producers, partners in exploration projects, refineries and the operating company for the trans-Alaska pipeline. In addition to companies providing traditional oilfield services, service companies operating directly in support of the primary companies include companies providing professional, technical and management services; construction companies; and transportation companies.

60% traditional services

In fact, the McDowell Group has found that the use of traditional oilfield services, presumably including activities such as drilling and well logging, only accounts for about 60 percent of the total oil industry spend on the services that it uses, Calvin said.

In 2010 primary companies in the oil and gas industry employed 4,000 Alaska residents, Calvin said. Traditional oilfield service companies employed 7,700 Alaskans, while other companies providing services to the oil industry employed 7,100 people in state. Spending by these employees and by service companies spawned another 26,000 Alaska jobs.

Adding up all of the figures leads to a conclusion that in 2010 the oil and gas industry ultimately filled the pay packets of 44,800 Alaskans to the tune of a total of $2.65 billion in payroll. Of those jobs, 25,400 were located in the Municipality of Anchorage. And for every job in a primary oil industry company, there are nine other oil industry related jobs, Calvin said.

Government revenues

Calvin said that the McDowell Group analysis did not include jobs created from

see MCDOWELL REPORT page 13

Alaska needs nonresident workers

The Alaska economy, in general, is very dependent on nonresident labor, Jim Calvin, a managing principal in the McDowell Group, told people attending the Alaska Oil and Gas Association's annual lunch on Oct. 27. Calvin was presenting a report by the McDowell Group on the role of the oil and gas industry in the Alaska economy.

In highly seasonal industries, such as seafood processing and visitor-related industries, the proportion of out-of-state workers is particularly high. But in the oil and gas industry, the relative number of non-resident workers varies considerably between different industry sectors.

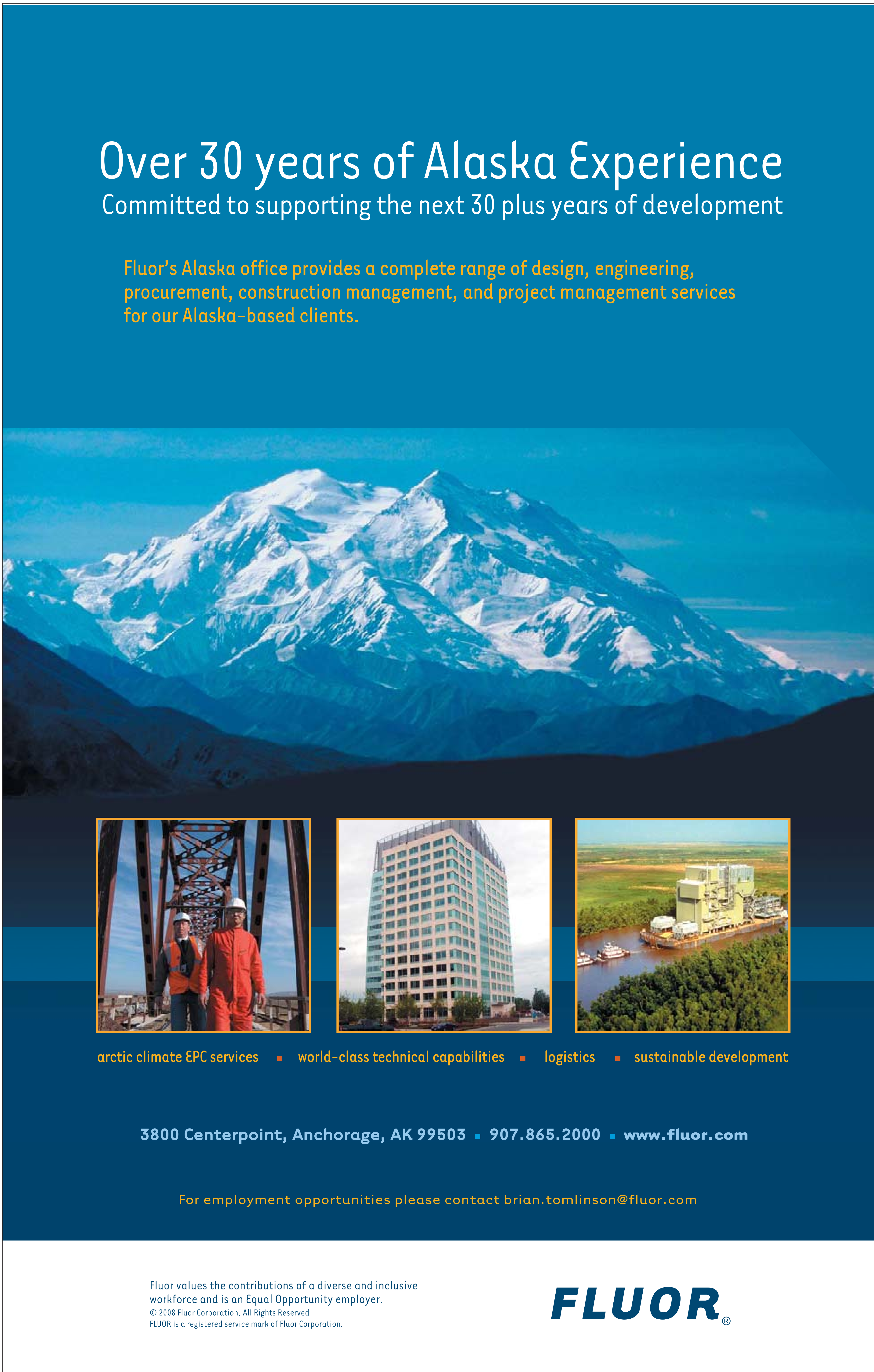
Using data from the Alaska Department of Labor, the McDowell Group found that 20 to 30 percent of the people employed in the oil and gas production components of the industry live out of state, a proportion somewhat similar to that in the mining industry, Calvin said. Resource extraction activities tend to be characterized by high labor mobility and have work rotas convenient for people traveling long distances from home, either from out of state or from many different parts of the state, Calvin said.

By contrast, refineries and the operator of the trans-Alaska pipeline have work forces consisting of more than 90 percent state residents, he said.

And over the past 10 years, the relative numbers of resident and nonresident oil and gas workers have tended to remain somewhat consistent, trending up and down in parallel, he said.

However, Calvin cautioned that the Department of Labor data used for the McDowell Group report may somewhat overstate the number of nonresident workers. The data comes from Alaska permanent fund dividend applications that require a person to live in state for nearly two years before being considered a state resident, he said.

—ALAN BAILEY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● GOVERNMENT

Shale development requirements tackled

Task force led by Division of Oil and Gas; DNR also moving ahead with issues impeding conventional oil, gas development in state

By KRISTEN NELSON

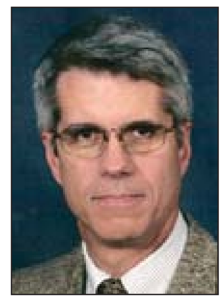
Petroleum News

What can the State of Alaska do to get more barrels of conventional oil into the trans-Alaska oil pipeline — and to ensure that the potential of shale oil production on the North Slope becomes a reality?

Bill Barron, director of the Department of Natural Resources' Division of Oil and Gas, addressed those questions from a permitting perspective at a meeting of the House Resources Committee in Anchorage Nov. 1.

DNR has been working with other departments on permitting issues in the state and has also established a multi-departmental shale task force to look specifically at requirements for shale development.

The state wants to make sure it is prepared for shale oil development, hence the task force, which includes DNR, the Department of Environmental Conservation, the Alaska Oil and Gas Conservation Commission, the Department of Fish and Game, the Department of Transportation and Public Facilities and the governor's office.



BILL BARRON

Immediate development possible

Barron said that successful exploration of the state's shale resources could lead to immediate development, but cautioned that drilling is required. He said all indications are that the Shublik and Kingak formations are very prospective for shale oil, but drilling will be required to verify the viability of the resource on the North Slope. Some shale plays in the Lower 48, such as the Marcellus and Bakken, have been very successful, he told the committee, but others have not. He said the Eagle Ford is expected to be an analogue for the Shublik, but Eagle Ford wells haven't been on line long enough to determine how long production will last.

Barron said that drilling shale wells is no different than drilling conventional wells, and said the state is well positioned to manage shale resource play development based on current statutes and regulations.

But, he cautioned, the pace and magnitude of permitting and development for North Slope shale oil could be significant, with a total well count comparable to wells currently in place on the North Slope — and with those new wells being drilled over a 10-year period, compared to the 30 years it has taken to drill the current North Slope well inventory.

Asked by Rep. Peggy Wilson, R-Wrangell, what staff increases agencies would need to handle that, Barron said the task force hadn't gotten that far yet, but would have information for the Legislature when it reconvenes next year.

The unit issue

Conventional oil production in the state takes place from units, groups of leases usually with different owners. The leases are unitized for production to ensure that there is no waste in producing the resource, a reaction to early days of drilling in the Lower 48 when landowners drilled as many wells as they could, competing with adjacent landowners to extract the oil, resulting in damaged reservoirs and less than maximum oil extraction.

State regulators in oil producing areas — the Alaska Oil and Gas Conservation Commission in Alaska — now ensure that drilling and production is done in such a way that resource extraction is maximized.

And landowners, in Alaska DNR's Division of Oil and Gas or the Bureau of Land Management for federal acreage, require that the acreage over a field be unitized.

But shale oil or gas doesn't occur in pools or fields. It is continuous over broad areas.

One of the main reasons for unitization — that oil or gas can be sucked from adjacent properties — doesn't apply to shale.

Unitization is for reservoir management, Barron told the committee in response to a question from Co-Chair Paul Seaton, R-Homer. Whether unitization is even appropriate for shale is in doubt.

There is no pressure communication from well to well, Barron said, and well drainage is limited.

Alaska regulators are discussing the unitization issue with regulators in areas like North Dakota where shale development is under way. Barron said most

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continued from page 12

SHALE DEVELOPMENT

jurisdictions have just changed spacing requirements for shale wells, rather than unitizing.

Hydraulic fracturing, natural gas

Hydraulic fracturing has been a big issue in Lower 48 shale development.

Barron said about 25 percent of Alaska wells — both on the North Slope and in Cook Inlet — are fractured, so the process isn't new to the state, or unique to shale play development. A large number of horizontal multistage hydraulic fractured wells are required to maintain production and economic feasibility from shale plays.

Frac fluids are approximately 98 percent water and sand and there would be no surface disposal of water in Alaska, Barron said.

Seaton asked about natural gas produced along with the oil.

Barron said that in the Bakken, where the oil wells are very low-rate, the associated gas is also produced at a low rate.

But it's not the same as conventional production — you can't re-inject natural gas into a shale formation, so disposal is more complex. With more wells, pumps will need power and gas could be used for that, he said.

But since the resource hasn't been drilled yet, it's not known whether the amount of gas will be small or large.

Conventional issues

Barron also reviewed issues impeding conventional North Slope development.

The permitting task force led by Deputy DNR Commissioner Ed Fogels is looking for overlaps and gaps in the state's permitting requirements, Barron said.

But, he told the committee, in permitting, "one man's impediment is another man's protection."

One issue is that smaller companies, and companies new to Alaska, are bidding on leases. These companies have little experience in permit sequencing and timeframes, may not have allotted enough time to address public concerns and local government requirements and are not familiar with conducting business in Alaska.

There is also a new issue, since the demise earlier in the year of the Alaska Coastal Management Program: Applicants are now responsible for project coordination with local, state and federal agencies. Barron said the permitting task force recognizes how critical coordination is; an Alaska project questionnaire is being developed to serve as a road map for permitting.

Drilling season, roads

Barron said finding a way to extend the drilling season would reduce one impediment.

And the "Roads to Resources" concept has value beyond the Foothills area.

Roads came up in the shale development discussion, with Sen. Cathy Giessel, R-Anchorage, asking about a requirement for gravel roads for shale play development. Barron said the state's best interest findings require ice roads for exploration, but not for development. And once Great Bear Petroleum, which acquired some 500,000 acres in last fall's state lease sales specifically for shale resources, drills its first four wells, in concept there would never be another exploration well for shale. Barron said once the resource is identified, every well will be drilled, fracked and produced.

All development on the North Slope is from gravel roads, he said, except Alpine and Badami which were done as roadless developments.

He said roadless developments haven't been beneficial for adjacent lease exploration, citing Badami as an example. If there had been a road into Badami, it would have significantly reduced the cost of exploring east of existing fields because ice roads would have been required just from the gravel road. A tremendous expanse of the North Slope has remained unexplored because of cost, he said.

"Roadless" was viewed as the right way to go, Barron said, but it may not be the right way in terms of long-term development.

Resources Co-Chair Eric Feige, R-Chickaloon, asked if there were areas other than the North Slope that would benefit from permanent roads.

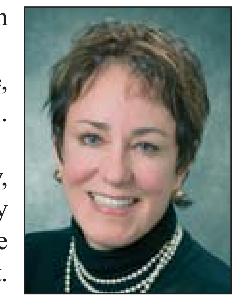
Barron said the west side of Cook Inlet would also benefit. The area has pipeline access, he said, but no roads, and a permanent road would increase the exploration opportunities. ●

Contact Kristen Nelson at knelson@petroleumnews.com

NATURAL GAS

George joints AGDC as admin director

The Alaska Gasline Development Corp. said Nov. 2 that Jamilia George has joined AGDC as director of administrative services.


JAMILIA GEORGE

George has most recently been with the Denali Commission as chief of staff for the state's executive branch.

A 30-year Alaskan, she has 27 years of government service, including more than 17 years as chief deputy for the U.S. Bankruptcy Courts in Alaska.

She received her juris doctor from Gonzaga University, holds a certificate in professional mediation from the University of Washington School of Law and is admitted to practice before the Alaska state and federal courts and the U.S. Supreme Court.

AGDC President Dan Fauske said George's "extensive experience makes her a valuable asset to AGDC as we continue to develop the Alaska Stand Alone Gas Pipeline project to access secure North Slope gas supplies for Interior and Southcentral Alaska."

AGDC, a subsidiary of the Alaska Housing Finance Corp., was mandated by House Bill 369 to produce a project plan for the development of an in-state natural gas pipeline, a plan presented to the Alaska Legislature on July 5.

—PETROLEUM NEWS

GOVERNMENT

BSEE appoints regulatory programs chief

The Bureau of Safety and Environmental Enforcement has appointed Doug Morris as the new chief of the agency's regulatory programs, BSEE announced Nov. 1. Morris will be responsible for developing and maintaining technical and operational standards; developing new regulations; and enhancing inspections and enforcement programs. He will also lead efforts to improve offshore operational safety and supervise BSEE's National Offshore Learning and Training Center, BSEE said.

Morris comes from the Energy Information Agency, or EIA, where he was director of the Reserves and Production Division and then became responsible for the Oil and Gas Supply and Financial Statistics Team. Prior to serving in EIA he served as group director for upstream and industry operations in the American Petroleum Institute.

Morris comes from the Energy Information Agency, or EIA, where he was director of the Reserves and Production Division and then became responsible for the Oil and Gas Supply and Financial Statistics Team. Prior to serving in EIA he served as group director for upstream and industry operations in the American Petroleum Institute. Morris had previously worked in the U.S. Minerals Management Service and in private industry.

"Throughout the recruitment process, we have looked for people who are technically skilled and experienced, who have a strong commitment to public service, and who can spearhead our ongoing efforts to enhance the safety of offshore exploration and production," said BSEE Director Michael Bromwich when announcing Morris's appointment."Because of his vast and diverse experience, both within the federal government and in private industry, Doug Morris brings to the agency a blend of personal qualities and professional qualifications that will help us achieve our goals. I look forward to having Doug on our team in this very important job."

—ALAN BAILEY

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MCDOWELL REPORT

government oil and gas royalties and taxes. In 2010 oil industry royalties and taxes of $4.9 billion accounted for 89 percent of total state revenues, he said.

A report from the University of Alaska Anchorage Institute of Social and Economic Research has indicated that oil industry related state government revenues generate as many as 60,000 jobs, Calvin said. That would suggest a total of more than 100,000 oil industry generated jobs in the state, a figure that is nearly one quarter of the total number of full- and part-time in-state job positions, he said.

And the oil and gas industry accounts for nearly 25 percent of Alaska's state gross product, the measure of the overall value of economic activity in the state, Calvin said.

"There's no other industry in state that comes anywhere near oil and gas in terms of its contribution to our gross state product," Calvin said. ●

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● LAND & LEASING

Parnell voices Point Thomson impatience

Alaska governor calls out other working interest owners yet to sign onto state deal with ExxonMobil on disputed oil and gas field

By WESLEY LOY

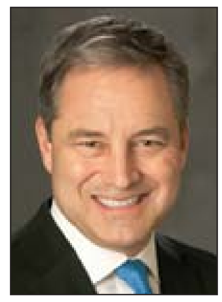
For Petroleum News

Alaska Gov. Sean Parnell is unhappy the legal conflict over Point Thomson, a rich but undeveloped North Slope oil and gas field, remains unresolved.

Speaking at the Oct. 27 annual luncheon of the Alaska Oil and Gas Association, a trade association of the state's oil producers, Parnell said a deal struck weeks ago between the state and Point Thomson unit operator ExxonMobil still lacked the endorsement of the field's other working interest owners.

The major working interest owners, aside from ExxonMobil, include BP, Chevron and ConocoPhillips.

"We got that Point Thomson settlement done last August, hammering out a resolution of that litigation with the unit operator, ExxonMobil. So what's the holdup?" Parnell said, speaking to a large audience at the AOGA event in downtown Anchorage. "Well, still, there's no public word from the other working interest owners about whether they're going to join us in the settlement with the unit operator and the state."



GOV. SEAN PARNELL

Parnell continued: "It's deeply troubling to me, and should be troubling to you as Alaskans, that this litigation has been pending through three administrations. The state negotiated a resolution with the unit operator, like we were supposed to. But the other working interest owners have yet to finalize the settlement."

Key for gas line

Parnell made his remarks in the context of the state's longtime goal of building a pipeline to carry North Slope natural gas to market.

Point Thomson gas, coupled with gas reserves in the giant Prudhoe Bay field, is considered important for supporting a pipeline, the governor said.

"Point Thomson gas represents one-fourth of the 35 trillion cubic feet of natural gas reserves that we know exist between Prudhoe and Point Thomson," he noted.

Point Thomson is located on the eastern North Slope, along the Beaufort Sea coastline next to the Arctic National Wildlife Refuge.

Although discovered long ago, with wells drilled in the 1970s, Point Thomson has seen no production to date. The field is rich not only in gas but holds hundreds of millions of barrels of petroleum liquids. Development would generate jobs, taxes and royalties.

State officials reached the end of their patience with the leaseholders in 2005, launching efforts to break up the unit and take back the state acreage at Point Thomson. Frank Murkowski was governor at the time.

ExxonMobil and its partners have since fought in court to preserve the unit, and the case currently sits before the Alaska Supreme Court. ExxonMobil has cited the lack of a multibillion-dollar gas pipeline as a primary reason why Point Thomson hasn't been developed.

Reaction to Parnell's remarks

On Aug. 15, during a legislative hearing, Alaska Natural Resources Commissioner Dan Sullivan revealed that a "resolution in principle" had been reached with ExxonMobil to settle the Point Thomson case.

He said ExxonMobil was discussing the settlement provisions with the other working interest owners, and the companies were working out "internal commercial terms."

But little has been heard publicly since Sullivan's revelation.

One factor holding up the deal could be the discontent among the other field owners over how they were treated during settlement talks between the state and ExxonMobil. In court filings, lawyers for BP, Chevron and ConocoPhillips complained that the companies had been shut out of the negotiations.

Representatives of those companies were present at the Dena'ina Civic and Convention Center to hear Parnell's remarks.

Spokespersons for two companies, Chevron and ConocoPhillips, had little to say after Petroleum News asked for comment.

"Chevron does not have any comments to offer on the Governor's remarks," Chevron's Roxanne Sinz said in an email.

"We do not generally comment on pending litigation issues," said Natalie Lowman, of ConocoPhillips.

BP was a little more talkative.

"The proposed agreement is complex," BP spokesman Steve Rinehart said by email. "We and other owners had asked to be involved in the discussions, but were not allowed. We are now working with the state and Exxon to understand both the settlement agreement and the development project that is embedded within the agreement."

ExxonMobil's David Eglinton offered this: "We are continuing to make progress on settlement, but additional work remains. We remain committed to working with Governor Parnell's administration and the other working interest owners to finalize a settlement. Settling Point Thomson litigation and securing necessary local, state and federal permits is imperative to maintain the pace of Point Thomson development."

What sort of development?

If the other working interest owners are mad, hopefully they aren't mad at the state for negotiating, as it customarily does, with the unit operator, Parnell told Petroleum News after his speech.

Even amid the legal conflict, ExxonMobil has made a start toward a Point Thomson development.

Between May 8, 2009, and Oct. 27, 2010, the company drilled a pair of wells at Point Thomson, the first sunk there since the early 1980s. It did so, ostensibly, with the blessing of the other working interest owners.

The "development wells," as ExxonMobil termed them, are part of a promised $1.3 billion project to start producing 10,000 barrels a day of natural gas condensate by year-end 2014.

That's a modest volume by North Slope production standards, and the state likely wants something more.

It will be interesting, then, to see what sort of development is called for under the state settlement with ExxonMobil, and whether the deal includes any commitments of Point Thomson gas to a pipeline project.

On another front, ExxonMobil is seeking a federal wetlands permit for Point Thomson production facilities, and the U.S. Army Corps of Engineers is drafting an environmental impact statement. The Corps is scheduled to release a draft EIS any day now, with a record of decision to be signed in August 2012. ●

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● PIPELINES & DOWNSTREAM

Kinder Morgan tests waters

Calls open season to double capacity of Trans Mountain to 600,000 bpd, fueling competition with Enbridge on routes to Asia-Pacific

By GARY PARK
For Petroleum News

Quietly operating below the radar while its Canadian rivals TransCanada and Enbridge are entangled in raging pipeline controversies, Kinder Morgan Canada is taking another step towards offering Alberta oil sands producers greater access to the Asia-Pacific region.

It has launched an open season that expires Jan. 19 to test shipper response to a proposed 300,000 barrels per day doubling of capacity on its Trans Mountain system from Alberta to the Port of Vancouver and Puget Sound in Washington state.

If it receives sufficient commitments for a project that could cost C$3.8 billion, Kinder Morgan will have strongly positioned itself to either fill the void should Enbridge's Northern Gateway project unravel, or go head-to-head against its competitor.

Currently, it is the only pipeline operator serving the emerging Asian market through small shipments from the Westridge marine terminal in Vancouver.

Planned in-service date of 2017

The open season aims to expand the role of that terminal by seeking binding 15- and 20-year transportation agreements on the 715-mile Trans Mountain system, with a planned in-service date of early 2017.

Although Kinder Morgan is putting its emphasis on expanding Trans Mountain's long-established southern route, it has not ruled out a second line to the deepwater port at Kitimat, on the northern British Columbia coast.

Kitimat is also Enbridge's planned terminal location for the 525,000 bpd Northern Gateway pipeline, which is facing a possible two-year hearing process before a joint panel of the National Energy Board and Environmental Assessment Agency.

The pressure is already on Kinder Morgan to enlarge Westridge. The Trans Mountain system is currently oversubscribed by up to 50 percent, partly because a pipeline leak in Alberta during the summer led the NEB to order a 20 percent reduction in volumes, forcing Kinder Morgan to restrict shipments to 44 percent of nominated volumes in November. Of the accepted nominations of 280,920 bpd, 44,877 bpd are destined for Westridge.

Ruling by end of year

The NEB is expected to rule before year's end on a Trans Mountain application to provide 54,000 bpd of firm dock service out of 79,000 bpd of dock capacity at Westridge, leaving the balance for spot shippers. That proposal is in response to an oversubscribed open season last year.

Kinder Morgan said 25 percent of the crude on the three or four tankers leaving Westridge every month is destined for Asia, compared with about 10 percent a year ago, and the rest for the U.S. Pacific Coast, strongly hinting at growing producer interest in accessing the Far East.

Cenovus Energy, one of Alberta's leading oil sands developers, has openly identified Asia as one of its likely alternative if the TransCanada Keystone XL pipeline from Alberta to the Texas Gulf Coast loses its struggle for approval by the Obama administration.

Kinder Morgan is confident it can use the existing Trans Mountain right of way for an additional 300,000 bpd without posing additional environmental concerns and said it has strong backing from First Nations, unlike the Northern Gateway proposal.

But Enbridge has countered that Northern Gateway could operate tankers out of Kitimat with twice the capacity of those using Westridge.

Tankers out of Vancouver

Although tankers from Westridge use a narrow and shallow channel through the densely populated center of Vancouver and close to the city's scenic treasures, Kinder Morgan has attracted only limited interest from environmentalists compared with the opposition facing Northern Gateway.

However, those days may be drawing to a close as municipal and federal politicians start to discuss the risks.

Derek Corrigan, mayor of Burnaby, where the Westridge terminal is located, said his community doubts Kinder Morgan's ability to manage an emergency situation, while federal Natural Resources Minister Joe Oliver is being pressured to hold a full consultation on the project.

So far, Oliver has said only that every major proposal will be reviewed by regulators and his government "respects the regulatory process." ●

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KEYSTONE DEBATE

region, saying he will respect the regulatory process that is now evaluating the project.

Alberta: Northern Gateway option

Newly installed Alberta Premier Alison Redford joined the pro-oil sands chorus, describing criticism of the sector as "short-sighted, misinformed and exaggerated" and making it clear her government will support both Keystone XL and Northern Gateway.

"If Keystone isn't approved, it's got to be Northern Gateway," she said. "We also have to look at Kinder Morgan's (Trans Mountain pipeline) because they have a regulatory corridor that allows for expansion."

There is speculation that India's energy giant Reliance Industries has been evaluating oil sands assets and may have been the September buyer for C$60 million of Oil sands Quest's Wallace Creek assets near the Cenovus joint venture properties.

If the Gateway pipeline and Trans Mountain expansion proceed, the United States would lose first call on Canadian crude and undermine its goal of energy security, Redford said.

The latest hiccup for Keystone has surfaced in Nebraska, where the state senate is holding a special session to discuss the proposed routing of Keystone.

Asia attracting interest

Regardless of whether the project is approved at the federal level later this year, Asia is attracting interest from pure-play oil sands producer Cenovus Energy, which has opened a data room to prospective joint venture partners for its 90,000 bpd Telephone Lake project and nearby undeveloped lands.

Chief Executive Officer Brian Ferguson said the "billions of barrels of recoverable oil" that are up for bids have allowed Cenovus to pre-qualify "several" potential partners.

They cover national oil companies, supermajors and multinationals based in Calgary, Houston, London, India and China, he said.

There is speculation that India's energy giant Reliance Industries has been evaluating oil sands assets and may have been the September buyer for C$60 million of Oil sands Quest's Wallace Creek assets near the Cenovus joint venture properties.

In addition, Oil and Natural Gas Corp., based in New Delhi, reportedly entered discussions last spring to acquire oil sands reserves.

Ferguson said the timing of a Cenovus deal will hinge on what progress is made over the next few months, adding the end result could involve, cash, asset swaps or other options, while Cenovus will file an application before yearend to upsize the initial Telegraph Lake project to 90,000 bpd from 35,000 bpd.

—GARY PARK

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ALYESKA PIPING

Costly campaign

The piping replacement work actually consists of several major projects, each to cost "tens of millions of dollars to complete," said Alyeska spokeswoman Michelle Egan.

Firms under existing contracts will handle part of the work, with some jobs to be put out for bid, Egan said.

The piping to be replaced is characterized as "dead leg, low and intermittent flow, and concrete encased piping," the summary document says. Such piping can't be excavated for inspection, or inspected internally with tools called pigs.

Alyeska has given regulators a schedule for doing the piping replacements. Pump Station 1 will see "the most complex and critical" project, Alyeska says. It will be the first station to have its below-ground crude oil piping rerouted to an above-ground configuration.

The final design for Pump Station 1 will be finished by year's end, with construction to start in the first quarter of 2012 and conclude in the fourth quarter of 2013, the schedule shows.

Projects will follow at pump stations 3, 4, 5 and 9, with all the piping replacements to be finished by the fourth quarter of 2014.

"Each of the pump stations will have a two year construction season to complete all of the piping work," the Alyeska summary says. "The first construction season will install civil foundations, pipe supports, trenches, and other preparatory work and the second season will install the piping and make the final tie-ins."

Aging pipeline

Alyeska is the Anchorage-based consortium that runs the trans-Alaska pipeline on behalf of owners BP, ConocoPhillips, ExxonMobil, Chevron and Koch Industries.

The pipeline has been moving oil from Prudhoe Bay and other North Slope fields since June 20, 1977.

Federal pipeline regulators hit Alyeska with a "notice of proposed safety order" in February, following the leak inside a Pump Station 1 building basement. The leak forced a pipeline shutdown lasting about three and a half days.

The leak was described as a booster pump manifold failure. A manifold is an arrangement of piping or valves designed to control, distribute or monitor fluid flow.

The mainline, 48-inch pipe was not involved.

Alyeska retained Det Norske Veritas, a Norwegian concern specializing in risk management, to do an independent investigation of the Pump Station 1 leak.

A 6-foot section of piping, containing the location of the leak, was removed and shipped to Det Norske Veritas for metallurgical analysis, the Alyeska summary says.

In their proposed safety order, federal pipeline regulators cited "multiple conditions" on the pipeline that appeared to pose an integrity risk. The concerns centered on the pipeline's declining oil throughput and the potential for freeze-ups and corrosion.

As part of the settlement Alyeska signed with PHMSA in August, Alyeska agreed to replace or remove hard-to-inspect oil piping.

Marine terminal involvement

"It's important to emphasize that a lot of these piping issues can be attributed to declining flow through our systems and that many of these piping projects were already planned," Alyeska's Egan said.

Aside from the pipeline itself, Alyeska operates the Valdez Marine Terminal, where the line ends and where tankers pick up crude for delivery to West Coast refineries. The terminal is a sprawling, waterfront complex of tanks, pipes and piers.

The Alyeska summary says a risk assessment was done not only for pump station piping, but also for marine terminal facility piping.

The summary, however, says nothing about any planned piping replacements at the terminal. ●

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Petroleum news

Oil Patch Bits

CGGVeritas seismic vessel to be used in Norway

CGGVeritas said Oct. 27 that the first project for its recently launched Oceanic Sirius X-BOW® seismic vessel will be a 3-D BroadSeis™ survey on the Avaldsnes field, potentially estimated to be the third largest oil discovery in Norway, on behalf of Lundin Petroleum.

As one of the most advanced, high-capacity seismic vessels worldwide, the Oceanic Sirius is designed for superior acquisition data quality combined with the highest environmental standards and the minimum operational downtime. Her operational efficiency is expected to match if not exceed the outstanding seismic performance already shown by her sister ship, the Oceanic Vega.

BroadSeis, the new CGGVeritas broadband marine solution, was selected to improve the resolution and imaging of the field. The vessel will acquire BroadSeis data with Sercel Sentinel® solid streamers equipped with the Sercel Nautilus® streamer control device. DoveTailTM, a proprietary CGGVeritas acquisition and processing solution designed to achieve more regular sampling and to reduce infill, will also be deployed on this project.

CGGVeritas is a leading international pure-play geophysical company delivering a wide range of technologies, services and equipment through Sercel, to its broad base of customers mainly throughout the global oil and gas industry.

TOTE president honored with 2011 achievement award

COURTESY TOTE

Totem Ocean Trailer Express Inc said Oct. 25 that its president, John Parrott, was honored earlier in the month by his alma mater, the U.S. Merchant Maritime Academy, with the 2011 Outstanding Professional Achievement Award.

The Outstanding Professional Achievement Award is given to the USMMA graduate "who best exemplifies the finest tradition of the Corps, 'Acta Non Verba' (meaning act, don't talk), by attaining personal achievement in their chosen field and thus lending honor and prestige to the USMMA."

Parrott graduated from the USMMA, located in Kings Point, N.Y., 1986 with a bachelor of science degree in Marine Transportation, continuing on to earn a master's of business administration from Seattle University. He holds a commission in the U.S. Naval Reserve and is a licensed master in the U.S. Merchant Marine, having sailed for 10 years aboard a

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BRPC UNITS

includes Brooks Range Development Corp. (the local development affiliate of BRPC), the Calgary-based independent TG World Energy Inc. and Nabors subsidiary Ramshorn Investments Inc.

he Tofkat and Putu units

BRPC applied to form the Putu unit in March 2011, but DNR didn't deem the application complete until July. The original proposal covered some 39,993 acres over 39 leases, including 28 owned jointly by the state and Arctic Slope Regional Corp., along the eastern edge of the Colville River, south of the Colville River unit, near Nuiqsut.

The original Putu unit proposed three exploration blocks — North, Southwest and Southeast — but DNR ultimately broke those into two units. The North block is now the Tofkat unit, while the Southwest and Southeast blocks are now the Putu unit to take advantage of the differing geologies and exploration histories within the region.

The Tofkat unit includes 21 leases owned jointly by the state and ASRC covering some 9,131 acres, while the Putu unit includes nine state leases covering some 21,946 acres.

The nine leases not included in either unit will expire at the end of their terms, unless unitized at some point in the future (although two leases expired on March 31, 2011).

DNR also increased the rental rates on numerous leases to make up for the potentially lost revenue it could collect by leasing that acreage out to another company.

Once the 15 leases in the Tofkat unit set to expire between July 31, 2012, and Aug. 31, 2013, reach the end of the primary terms, the rental rates will jump to $4.50 per acre, up from $3 per acre, as will the nine leases in the Putu unit set to expire Aug. 31, 2012.

The working interest owners must also execute a new agreement with ASRC.

Tofkat geology known

The Tofkat unit includes three wells BRPC drilled in the area in early 2008.

BRPC drilled the Tofkat No. 1 well and the Tofkat No. 1-A and Tofkat No. 1-B sidetracks in the N Block in 2008, and in later 2008 acquired proprietary seismic over the area.

The primary target of those wells was "Kuparuk C sands, Brookian Albian-age turbidite fans and Jurassic-age Alpine sands," three geologic intervals with oil producing reservoirs in the Colville River unit some six miles north of the Tofkat unit.

After reviewing geologic and geophysical information in the application, DNR determined that "a portion of the N block does encompass an oil reservoir within the C member of the Kuparuk Formation, and two reasonably defined and delineated potential hydrocarbon accumulations in the shallower Nanushuk and Torok formations."

Because the wells drilled in early 2008 penetrated and evaluated both the reservoir and the two potential accumulations, the Tofkat unit is more defined than the new Putu unit.

Under the plan of exploration for the Tofkat unit, BRPC must drill and complete the Tofkat No. 2 well and Tofkat No. 2-A sidetrack into the Kuparuk formation by May 31, 2013. The working interest owners must sanction the Tofkat development project by Oct. 1, 2013 — and keep it sanctioned through production — or terminate the unit.

Putu needs more drilling

Although not home to any previous exploration drilling, the new Putu unit sits mostly within a 220-square mile 3-D seismic package that BRPC acquired in 2008 and used to identify "prospective targets they believe have a higher probability of encountering reservoir quality sand" than the four previous wells drilled within two miles of the unit.

Those wells, drilled between 1972 and 2006, all encountered hydrocarbon-bearing zones in the Brookian Torok formation, "but so far these strata have lacked sufficient reservoir quality to likely produce or warrant development by the operators," DNR noted in its decision, adding, "encountering reservoir quality strata with sufficient connectivity has historically been the crux to unlocking the Brookian potential on the North Slope."

ARCO drilled the Itkillik River Unit No. 1 to 15,321 feet in 1972, attempting nine drill stem production tests and taking three conventional core samples from the well. The deepest of those tests — at an interval in the Kekiktuk formation between 14,510 and 14,726 feet — flowed at an estimated rate of 3,500 cubic feet per day over six hours.

Phillips Alaska drilled the Atlas No. 1 well and Atlas No. 1-A sidetrack to 7,335 and 8,454 feet respectively in 2001, finding hydrocarbon-bearing zones in the Torok Formation but not gathering fluid samples or conducting production tests at either well.

Pioneer Natural Resources Alaska drilled the Cronus No. 1 well to 7,941 feet in 2006 to explore a Brookian sourced target in the Torok formation similar to the Atlas wells.

Cronus No. 1 encountered two zones in the Torok formation that appeared to be hydrocarbon bearing, but Pioneer ultimately decided they were too tight to produce.

Under the agreement for the new Putu unit, BRPC must post a $10 million performance bond by Feb. 1, 2012, to guarantee that it will commit to a four-well drilling program.

The first payment of $1 million is due on May 31, 2012.

The company must then drill four wells into the Upper Jurassic-age strata of the Kingak formation by May 31, 2013, two targeting the Musketeer trend (Brookian Sequence Boundary C) and two targeting the Big Foot trend (Brookian Sequence Boundary BC).

S Miluveach and Kachemach

BRPC applied to form the Southern Miluveach unit in December 2010 and DNR deemed the application complete in late June after the company submitted two revisions.

The original proposal covered some 60,864 acres over 40 leases, including 11 owned jointly by the state and ASRC, a mile to the northeast of the new Tofkat and Putu units.

The initial application proposed six exploration blocks: Northeast, Southeast, Northwest, Southwest, West and South. The state ultimately created the Southern Miluveach unit out of the Southeast block and the Kachemach unit out of the West and Northwest blocks.

The Southern Miluveach unit now includes five state leases covering some 8,960 acres, while the Kachemach unit includes 11 state/ASRC leases covering some 16,487 acres.

The leases not included in either unit will expire at the end of their terms.

DNR also increased the rental rates on 18 leases in the Kachemach unit and five leases in the Southern Miluveach unit to $4.50 per acre from $3 per acre to make up for the lost revenue it might have collected by leasing the acreage out to another company.

Oil shows in the Torok

The first wells drilled in the area — the Colville No. 1 in 1966 and the Kookpuk No. 1 in 1967 — targeted Lisburne formation, but considered it unsuccessful after an evaluation.

The Kuparuk River unit to the east produces from the Lower Cretaceous-age Kuparuk River formation at the Kuparuk PA and the shallower Upper-Cretaceous Bermuda sands of the Seabee formation at the Tarn PA. The Colville River unit to the west produces from the Jurassic-age Alpine and Nechelik sands in the Kingak formation, from the Lower Cretaceous-age Kuparuk C sand and from Upper Cretaceous-age Nanuq sands in the Torok formation and shallower Qannik sands of the Nanushuk formation.

ARCO drilled the Colville River No. 1 well to 7,300 feet in 1993. Although the original objective in the Cretaceous-age sands of the Kuparuk formation proved to be unsuccessful, the company did encounter

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OIL PATCH BITS

wide range of vessel types and trade routes.

The USMMA was formed in 1938 to provide quality education and training for the U.S. maritime trade. Today, approximately 300 students are accepted to the program each year. Graduates received bachelor's of science degrees and are specifically trained for careers in the maritime industry. Approximately one-third of graduates go on to serve as merchant marine officers, another third seek careers in private industry, with the remaining third choosing to be commissioned officers in the U.S. military.

Canrig licenses selected MPO Drilling Technologies

Nabors Industries Ltd. said Sept. 19 that its wholly owned subsidiaries Canrig Drilling Technology International Ltd. and Canrig Drilling Technology Ltd. have entered into long-term agreements with Managed Pressure Operations International Ltd., whereby Canrig will license from MPO certain technologies related to managed pressure drilling. MPO is a leading provider of MPD (managed pressure drilling) solutions including its Non-Stop Driller and Total Control Driller. The Canrig license is exclusive to several major onshore markets, including North, Central and South America and Saudi Arabia. In addition, Canrig will have nonexclusive rights to other onshore markets. The agreements also facilitate technological and engineering collaboration between Canrig and MPO in developing more advanced, cost-efficient MPD systems.

"Over 70 percent of Nabors U.S. rigs are doing some form of managed pressure drilling utilizing third-party equipment and technology. A primary goal of this venture is to develop and implement a fleet of MPD-Ready™ rigs across the global operations of Nabors utilizing these leading edge technologies. We extensively evaluated the various MPD systems and concluded that MPO was the best alternative to facilitate our entry into this growing area, while creating economies and efficiencies for our customers," said Chris Papouras, president of Canrig.

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BRPC UNITS

"weak oil shows" in the Torok formation.

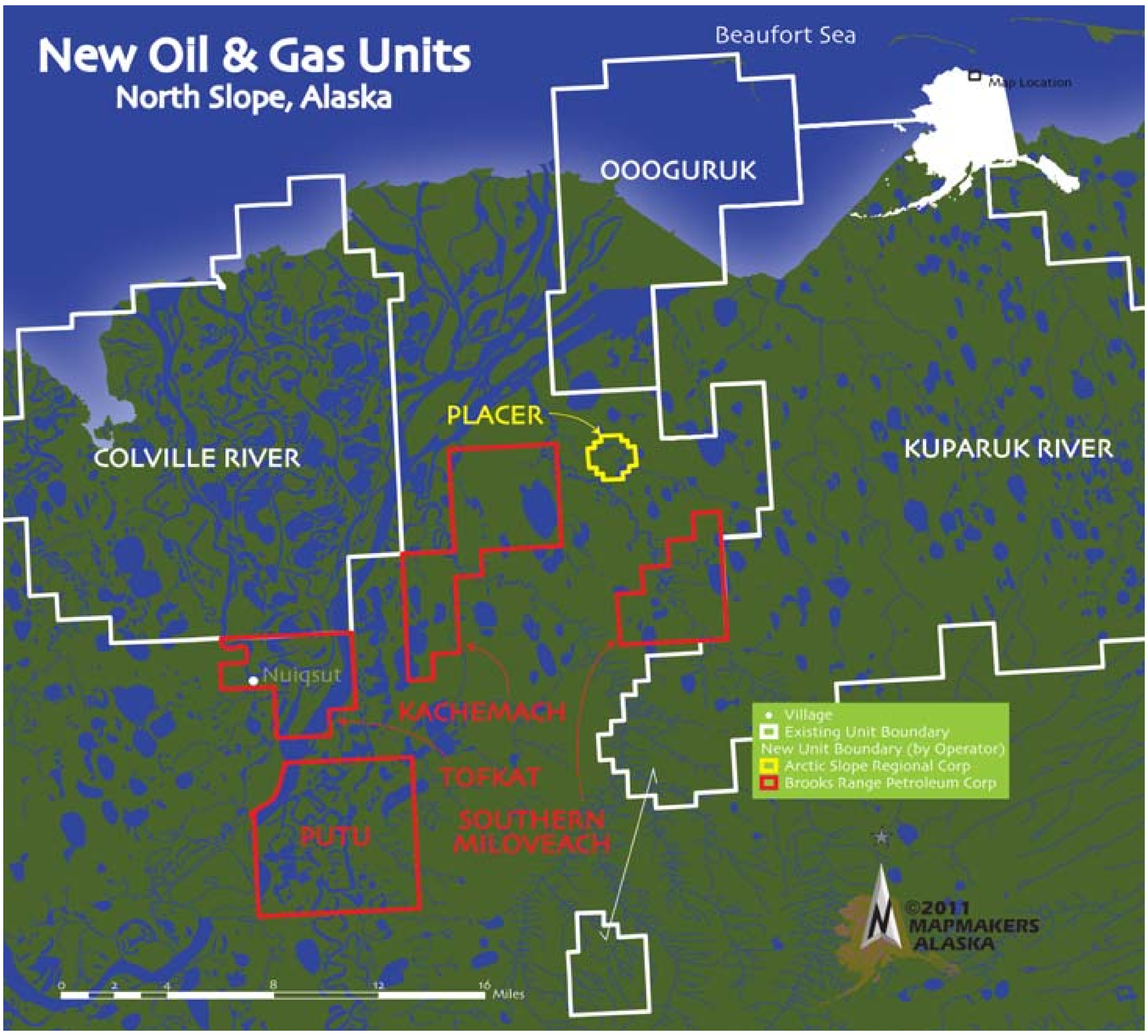
ConocoPhillips drilled the KRU-2L-03 well as an exploration step out from the Tarn 2L drill site in 2002, reaching a bottom hole location in the southeast corner of the Southern Miluveach unit at 11,316 feet to target Kuparuk C sand, but later gave up the lease.

ConocoPhillips drilled the Oberon No. 1 well eight miles west of KRU-2L-03 in 2003 to 7,580 feet targeting the Kuparuk C sand and the Alpine sands in the Kingak formation.

BRPC participated in the Ataruq No. 2 and Ataruq No. 2A well and sidetrack that Kerr McGee drilled in the proposed unit area in 2005 to 7,400 feet and 11,242 feet respectively to target Cretaceous-age Brookian submarine fans and the deeper Lower Cretaceous Kuparuk formation before reaching a total depth in the Miluveach formation, encountering oil shows in the Brookian formation but not in the Kuparuk formation.

The 2008 seismic survey covered the western half of the original Southern Miluveach unit and this year BRPC acquired a license for an earlier survey covering the eastern half, identifying potential stratigraphic traps in both the Brookian and Kuparuk formations.

BRPC drilled North Tarn No. 1 in early 2011 to 6,223 feet, identifying an oil reservoir in the Kuparuk C sand in the SE Block. BRPC also believes there could be a potential accumulation in the Nanushuk formation in the W and NW Blocks. The Nanushuk produces oil at the Qannik sands of the Colville River unit 11 miles west of the unit.



Six wells in the two units

Under the agreement for the new Southern Miluveach unit, BRPC must complete three wells — the North Tarn No. 1-A well, the Mustang No. 1 well and the Mustang No. 2 well or sidetrack — into the Kuparuk formation by May 31, 2012, and the working interest owners must sanction the Mustang development project by Oct. 1, 2012.

The Kachemach unit is now divided into two exploration blocks, Block A and Block B.

Under the Kachemach unit agreement, BRPC must complete one well in Block A targeting the Caribou trend (Brookian Sequence Boundary F) and one well in Block A targeting the Moonlight trend (TP4-2 Nanushuk prospect) by May 31, 2013.

If BRPC meets those commitments the company must then commit to complete one well in Block B targeting the Moonlight trend (TP4-1 Nanushuk prospect) by May 31, 2014.

Adds to other units

The two decisions make BRPC the operator of five units on the North Slope.

In addition to the four new units, DNR approved the formation of the 52,876-acre Beechey Point unit in the Gwydyr Bay region north of Prudhoe Bay in September 2009.

Earlier this year, BRPC also applied to form the Greater Bullen unit in the area between the Point Thomson and Badami units on the eastern North Slope, but recently withdrew that application and announced plans to apply for a smaller unit in the area next year. ●

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CIRI COAL

ment."

CIRI land

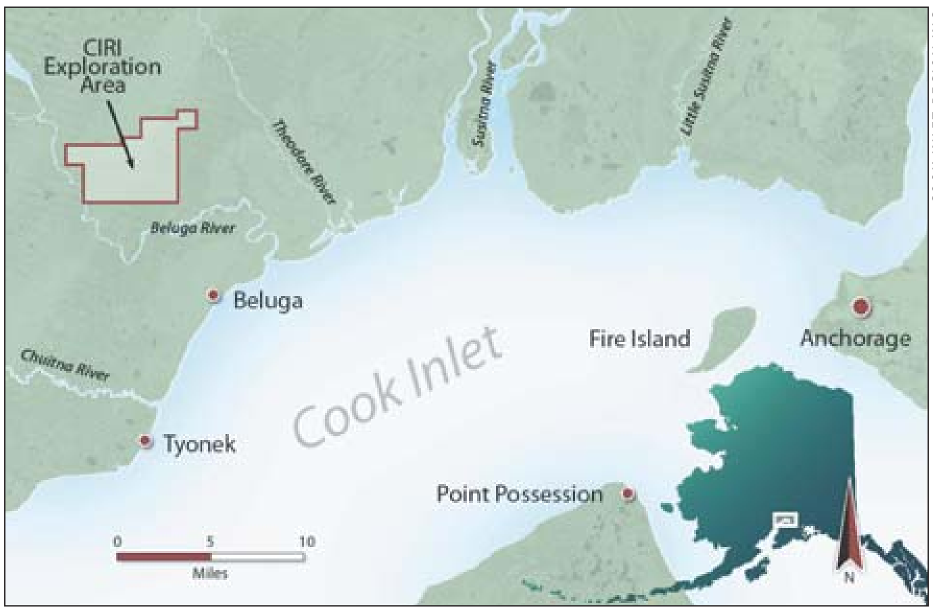
Stone Horn Ridge LLC, a joint venture between CIRI and Laurus Energy, is investigating the potential UCG development at a site called Stone Horn Ridge, northeast of the Beluga River, in an area where CIRI owns both the surface and subsurface land. Laurus Energy is a Houston-based affiliate of Ergo Exergy, a UCG technology company based in Montreal, Canada.

UCG involves the pumping of compressed air through a well into a coal seam deep underground to enable the controlled underground combustion of some coal; the heat from the burn converts excess air and the bulk of the coal to synthetic gas for delivery to the surface through production wells. It would be possible to burn the synthetic gas for power generation or to convert it to methane, the prime ingredient of natural gas. Other potential applications include the production of jet fuel by a gas-to-liquids process, or the production of fertilizer.

And, since the coal is processed deep underground, the UCG process eliminates much of the environmental impact of conventional coal mining and burning.

"We believe that UCG is a technology by which you can access this world-class energy resource in an environmentally acceptable manner," Schutt said.

Schutt also assured the legislators that the underground burn required for the UCG process could be stopped very easily by closing off the flow of air required for combustion.



COOK INLET REGION INC.

Cook Inlet Region Inc. wants to develop an underground coal gasification plant at Stone Horn Ridge on the west side of the Cook Inlet.

Multiple coal seams

Schutt said that the Stone Horn Ridge joint venture has found multiple, thick coal seams at depths below 650 feet in the Stone Horn Ridge area. The geologic setting of the coal appears favorable for the development of a UCG plant, although the joint venture is still in the process of collecting data and modeling the geology of the project site, he said.

The 13 core holes drilled for the exploration phase of the project penetrated depths ranging from about 700 feet to about 2,600 feet — the project team collected rock core and wireline data from the holes. Field and laboratory examination of rock samples; logging of the drilling mud; and field tests of the desorption of gas from coal samples also added to the data from the project site. That data have enabled the construction of a comprehensive computer-based geologic model of the site that has provided a preliminary validation of the existence of a commercial UCG resource.

The next step will be to carry out a high-resolution shallow seismic survey, gathering eight line-miles of data along three lines over a period of about 25-30 days.

"With that data we'll complete our preliminary model of the site, incorporating that with the data that we already have, and that will help us move to the next phase of the program, which is the (resource) characterization phase," Schutt said.

Conceptual engineering

The joint venture has already commissioned and obtained a conceptual engineering and cost analysis for a UCG development at Stone Horn Ridge, with the analysis considering various options for the use of UCG-generated synthetic gas, Schutt said.

The geologic modeling indicates the existence of about 300 million tons of coal in the Stone Horn Ridge site, a UCG resource equivalent to perhaps a little more than 4.8 trillion cubic feet of natural gas, with potential gas production rates in the range of 20 billion to 90 billion cubic feet per year, Schutt said.

And CIRI thinks that UCG-fueled electricity generation, for example, would prove significantly cheaper than generation from Cook Inlet basin natural gas, Schutt said.

But, with the project being at the leading edge of UCG technology deployment, CIRI is taking its time, being "pretty deliberate and responsible" and talking to stakeholders as the project moves forward, Schutt said.

"We're pretty excited about the project and its potential, but we do also realize that we've got a lot of work in front of us," he said.

—ALAN BAILEY

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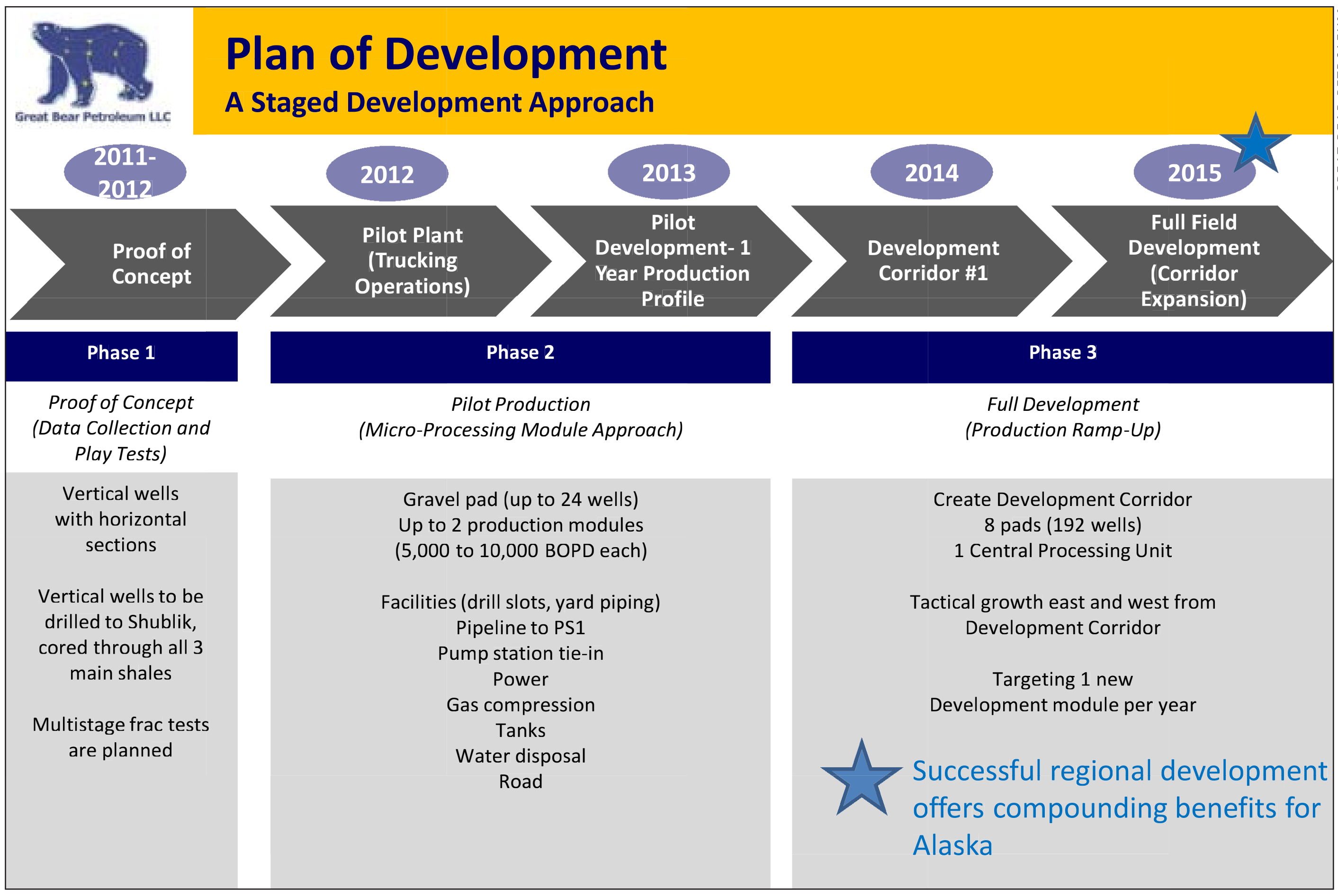
ALASKA SHALE

In the year since Great Bear first entered Alaska by winning approximately 500,000 acres in the state's Oct. 27, 2010, North Slope areawide lease sale, Duncan said his company has "made a huge amount of progress" and is "working very, very closely" with its "industry partners, the service industry, the state agencies, the North Slope villages … to find good solutions to the challenges that we face in developing shale resources for the state of Alaska."



GREAT BEAR PETROLEUM

Lots and lots of brackish water

But none of those challenges, he said in the course of his presentation, are major impediments, including water for fracking.

Unlike North Dakota and Texas, Great Bear's acreage south of the giant Prudhoe Bay and Kuparuk River oil fields, has a near limitless supply of subsurface, brackish water sources, between 2,000 and 5,000 feet deep, that are "very likely ideal for frack make up," Duncan said.

"We thought this going in but it has been confirmed repeatedly in the last several months of work. … That's a really good thing for Alaska," he said.

Water makes up about 98 percent of the solution needed for the hydraulic fracturing that Great Bear will have to do in order to coax the hydrocarbons from Alaska's three world class shale source rocks beneath its acreage.

Current water cycling technologies allow Great Bear to recover about 90 percent of the used water for reuse in fracking operations. The remaining water, Duncan said, "will be disposed of in either existing disposal facilities in north Alaska or in our own infield, custom-built, facilities as our program grows and those facilities become … necessary."

This time next year

"We have worked very, very hard in the last year to build a testing program that will allow us to have … a very technically based, hard science discussion about what this play means for Alaska," about a year from now, he said.

Assuming the partners are successful with their proof of concept programs, this time next year Duncan hopes Great Bear will be "moving toward constructing a pilot development pad … built with a modular processing unit on it that is capable of processing the produced fluids to TAPS-spec oil."

"We want to deliver oil to Alyeska that's ready to go in the pipeline," he said, explaining the pilot development oil will be trucked from the gravel pad to Pump Station 1.

Great Bear intends to produce from the development pad for one year in order to create "a collection of well production curves for North Slope shale oil development."

Great Bear's overhead slide titled, "Plan of Development, A Staged Development Approach," shows the pilot gravel pad having up to 24 wells with as many as two production modules that can handle 5,000 to 10,000 barrels of liquids per day each, but he thinks six wells and one 5,000 barrel a day module will likely be sufficient.

Sen. Tom Wagoner asked whether Duncan expected to produce 5,000 barrels a day from the six wells.

Duncan said he would be able provide a definitive answer after the proof of concept test wells are drilled, fracked and tested. Once Great Bear has all its permits and authorizations in place — and has secured a drilling rig — that program could get under way in November or December, state regulators said.

However, Duncan does not expect production from the wells on the development pad to be significant.

"A certain amount of water production is expected; a certain amount of gas production is expected," he said. "Gas production's good. Gas provides us reservoir energy to help lift oil to surface. … All of our rigs, all of our pumps, all of our equipment are AC. We will have a huge power demand from our infield operations. It's our expectation that much of the gas production will be for infield use. In our plan … we are also budgeting for a gas line to Prudhoe. If we have excess gas production we have no intention of venting it, we have no intention of flaring it. Our gas will be taken to Prudhoe or, just as with water disposal, we will build a subsurface storage facility on our own acreage. We have the capability of doing that. Our objective is not to waste the molecules. Not one Btu, actually, will be thrown away. That's our objective."

Two years from now

"Roughly two years from now," Duncan hopes to be "holding up" a graph that shows a tight curve and saying, "Here's the flush production in the first few months, here's what the decline curve looks like after a year of production."

Wells that produce liquids and gas from source rocks such as shale tend to produce at relatively strong rates for the first few months and then drop off fairly drastically, leveling out to produce at a lower, but steady, rate for many years.

Having a year of production under Great Bear's belt, "allows all of us to make a very educated judgment on how aggressively we pursue full field development," Duncan said.

Next, full field development, 200 wells per year

"As that decline curve, or as that tight curve develops, we will be in constant communication with you," he told lawmakers. "You have to be as informed as we are about what is happening because that really qualifies and allows us all to judge how aggressively we want to pursue the full field development that we all hope for, because that's a really good thing for the state. But that's two years out. One year from now we'll be going to pilot development; a year after that we'll have tight curves in front of us and we'll be sanctioning then, hopefully, corridor development — that's the 200 hundred wells a year."

In talking to legislators about the eight slides that were part of his presentation, Duncan referred them to "Plan of Development, Phased Development Approach — 3 Main Phases," which presumes success in the company's initial testing program.

The slide "captures both the concept of a pilot pad (and) … illustrates what we see as a corridor, full field, development program," involving eight pads and 192 wells per year, he said.

Duncan cautioned that the corridor illustration was schematic.

"It's not necessarily going to be north-south continuous. It may have a series of east-west or northwest-southeast or north-east-southwest spurs to it. The idea is, once we hit the full field development program we'll have a large activity set knitted together with infrastructure. Our current plan, our proposal, calls for a dedicated Great Bear pipeline system that connects all of our corridor development wells to the north, to TAPS."

Central processing facility

At some point Great Bear will move

see **ALASKA SHALE** *page 20*

ALASKA DIVISION OF OIL & GAS

Well Facts

- Alaskan analog is thought to be Eagle Ford Shale, TX

	Bakken	Eagle Ford	Shublik	L. Kingak	Hue/GRZ
Total Organic Carbon	10% avg	2-7%	2-3% avg	5% avg	3% avg
Main Kerogen Types	I/II (oil)	I/II (oil)	I/II-S (oil)	II/III (oil-gas)	II/III (oil-gas)
Oil Gravity, °API	42°	30-50°	24-45°	40°	38°
Thickness	up to 100 ft	50-250 ft	0-600 ft	175-550 ft	100-800 ft
Thermal Maturity	Imm-Oil-Gas	Imm-Oil-Gas	Imm-Oil-Gas	Imm-Oil-Gas	Imm-Oil-Gas
Lithology & Variability	Sh-Slts-Sh	Sh-Slts-Ls	Sh-Slts-Ls	Shale	Sh-Tuff
Brittleness	Yes - Quartz	Yes - Calcite	Yes - Calcite	No ?	No ?
Natural Fractures	Yes	Locally	some zones	?	?
Overpressure	Yes	Locally	?	Probably	Locally

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ALASKA SHALE

from modular processing units on individual pads to a central processing facility, or CPF.

Will it be shared with other operators?

"We presume that if others move at the same pace that we're moving, and develop oil and gas in the general area of our central processing facility that we're proposing, simultaneously than certainly a discussion can be had about shared facilities," Duncan said after posing the question himself.

"Currently we're planning central processing facilities specifically for our production, but we're not opposed to shared facilities. There's no one else doing this right now, so for the sake of planning it's our central processing facility."

According to Duncan, more than 200 wells are drilled each month in both South Texas' Eagle Ford and North Dakota's Bakken.

Where will the workers come from?

When asked where the work force to execute Great Bear's plans would come from, Duncan said, "The short answer is, the work force doesn't exist today in Alaska," but he is hoping that by working with local educators, that will change.

"Early on we visited the Fairbanks Pipeline Training Center, specifically to talk to the staff there about the sheer scale of what we were embarking on — the sheer number of jobs that we expected to be required. Imagine the hundreds of miles of gathering lines, the pipefitters, welders, truck drivers, skilled labor of all kind that will be employed here."

And Duncan is quick to point out, source rock exploitation doesn't involve just a temporary increase in jobs.

"In full field development, this program will generate, long-term, thousands of jobs. Not a spike. There's constant upward pressure on activity. … There's constant, long-term, accretive investment. That backdrop of activity requires a tremendous number of skilled people, and for that matter a tremendous number of grocery store clerks and teachers and all the rest," he said.

The "sheer life span" of what Great Bear is proposing, "40-years plus. It's a generational thing. It's not flipping a light switch to fix this. It's starting now, staying really focused, building and having it accretive. Two hundred this year, 500 next year, a 1,000 the next year, 2,000 new staff trained the following year," Duncan said.

Duncan is also looking at tapping people who are exiting the military.

Less than one month's wells

So what about those 200 wells Great Bear expects to drill every year, starting in 2014?

Duncan said the reaction he gets to that number from some Alaskans is "almost recoil," because it's so many more wells than are drilled annually in the entire state.

What's more, Great Bear's earlier presentations showed that level of drilling would continue for 45 years.

How does 200 wells compare to the number of wells drilled in the Bakken and Eagle Ford shale plays?

According to Duncan, more than 200 wells are drilled each month in both South Texas' Eagle Ford and North Dakota's Bakken. ●

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