Petroleum news

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Summer in western North Dakota

VERN WHITTEN PHOTOGRAPHY

Exxon more than doubles daily Bakken output since XTO buy

Exxon Mobil Corp.'s production from the Bakken petroleum system has more than doubled since it entered the Williston basin in mid-2010 with its acquisition of XTO Energy, a company executive said July 26.

"We have moved into a development phase across our roughly 400,000 net acre leasehold. In the first half of 2012, we turned 40 wells to sales, nearly double the pace of 2011. In the second quarter of 2012, our gross operated Bakken production increased by 60 percent over the prior year quarter. Since our entry into the play, we have more than doubled gross operative production to approximately 32,000 oil equivalent barrels per

see EXXON OUPUT page 19

Despite weather setbacks and commodity price slide, Crescent Point, PetroBakken stay course

Of the two key players in the Canadian sector of the Bakken, PetroBakken posted a 10 percent increase in its overall second-quarter production while recording a loss for the period, while Crescent Point Energy, feeding off recent acquisitions, reported strong growth in production and profits while raising its target for year-end production.

PetroBakken said its output for the latest quarter was 38,715 barrels of oil equivalent per day (83 percent light oil and liquids), with the Bakken business unit averaging 14,819 boepd after disposing of 2,900 boepd of non-core volumes.

The company's net loss was C$21.51 million, including a

see CANADIAN BAKKEN page 20

ND crude output continues to rise

The North Dakota Department of Mineral Resources says state oil producers pumped an average of 660,322 barrels of oil each day in June, per a report the agency released Aug. 14.

That's up from about 639,277 barrels a day in May and 609,503 in April, per DMR records.

There were 7,352 producing wells in June, as compared to 7,188, in May and 7,036 wells in April.

North Dakota drillers produced almost 20 million barrels of oil in June, up from 11.5 million barrels for the same month a year ago.

The state produced almost 34 percent more oil than Alaska in June, the fourth consecutive month that North Dakota out-produced the northernmost state, usurping Alaska's position as the second largest oil producing state in the union.

Check out the full DMR report at https://www.dmr.nd.gov/oilgas/mpr/2012_06.pdf.

—PETROLEUM NEWS BAKKEN

LAND & LEASING

Serka enters ND

Lease auction draws $11.7 million, as well as a new diverse player

By KAY CASHMAN
Petroleum News Bakken

The State of North Dakota's most recent oil and gas lease auction garnered $11.682 million in bonus bids, as well as drawing a new player — Serka Services LLC, a U.S. subsidiary of Istanbul, Turkey-based Adali Holding, which is a long-time construction and services contractor with the U.S. military in Europe and the Middle East.

Serka was also a new bidder in the federal government's July oil and gas lease sale for North Dakota and South Dakota, which drew $3,397,124 in high

see SERKA page 16

Kodiak wins online tract

At $7,003 per acre Kodiak Oil and Gas (USA) Inc. was high bidder in the Aug. 16 online auction of Tract OG-12-01183, a parcel in southeastern Williams County by the North Dakota Department of Trust Lands Minerals Management Division via EnergyNet.

The bonus bid was $560,240 for 80 acres. Adding the bidder's premium, a lease fee and state sales fee, the total amount Kodiak paid was $571,854.80.

see KODIAK page 16

FINANCE & ECONOMY

Marathon dumps rigs

Cazalot: Commodity prices, costs require a 'more disciplined' approach to spending

By RAY TYSON
Petroleum News Bakken

Lower commodity prices and high operating expenses are causing Marathon Oil Corp. to shed drilling rigs in several of its key U.S. shale plays, including the Bakken.

"This lower price environment, coupled with costs that have not declined at a comparable rate, dictate a more disciplined level of domestic spending and activity," Clarence P. Cazalot, Marathon's chief executive officer, said Aug. 1 during the company's 2012 second-quarter earnings call.

For the remainder of 2012 and perhaps into 2013,

CLARENCE P. CAZALOT

he said, Marathon's rig count is being reduced from eight to five in North Dakota's Bakken and from six to two in Oklahoma's Anadarko Woodford.

"We believe we can maintain flat production in both of these areas through 2013 at these rig levels," Cazalot said. "But obviously, we retain the flexibility to ramp back up, if prices and/or costs improve."

208 Bakken rigs reported

The total rig count in North Dakota's Bakken averaged 209 in April, 211 in May and 213 in June, then dropped to 208 in mid-July, according to the last offi-

see MARATHON RIGS page 19

NATURAL GAS

Exciting future for gas

Results of the ND study can be used as planning tool for industry and government

By MIKE ELLERD
For Petroleum News Bakken

By 2025 natural gas production in the Williston basin could increase nearly six-fold over current levels, pushing North Dakota into a competitive position in the U.S. natural gas market. That was one of the conclusions drawn by Bentek Energy in a recently released report commissioned by the North Dakota Pipeline Authority and North Dakota Industrial Commission.

Based on its high case scenario, the study also found that oil production could quadruple to 2.8 million barrels per day by 2025.

Titled "The Williston Basin: Greasing the Gears for Growth in North Dakota," the Bentek report was commissioned to forecast natural gas production in the Williston basin through 2025 to determine whether North Dakota has sufficient infrastructure to handle natural gas demands in the future as oil wells mature and the gas-to-oil, GOR, ratio changes.

The growth in natural gas production in the basin will have a significant impact on the pipelines and other infrastructure necessary to handle the predicted volumes of natural gas according to Justin Kringstad, director of the North Dakota Pipeline

see FUTURE FOR GAS page 12

The current issue of Petroleum News Bakken is enclosed.

Shell continues to delay drilling, waiting for containment barge

Although Shell has sent three of the vessels from its Arctic drilling fleet north to the Chukchi Sea, in preparation for its planned outer continental shelf exploratory drilling, the company's drilling program remains on hold, waiting for the completion of retrofit work on the company's containment barge, the Arctic Challenger, and U.S. Coast Guard certification of the vessel.

The company has installed its new Arctic oil containment system in the barge as part its oil spill contingency arrangements. And before the vessel can depart Seattle, where the system retrofit is being done, all work on the vessel must be completed and the Coast Guard must certify the vessel as safe for its intended use.

see **SHELL DRILLING** page 17

Arctic route in mix: NWT premier suggests Beaufort to Asia

Nothing is off the table when it comes to shipping Canadian crude to Asia, not even opening a route from the Beaufort Sea.

Amid the raging battle over Enbridge's Northern Gateway project and Kinder Morgan's planned expansion of its Trans Mountain system, to accommodate a combined 975,000 barrels per day of new pipeline capacity to the British Columbia coast, Northwest Territories Premier Bob McLeod said he will support a northern option.

Given the opposition to crude bitumen pipelines in British Columbia, he suggested the Alberta government should consider a pipeline down the Mackenzie River Valley to a tanker terminal on the Beaufort Sea.

see **ARCTIC ROUTE** page 20

LAND & LEASING

Protection trumps

Interior's preferred NPR-A plan emphasizes environmental conservation

By ALAN BAILEY
Petroleum News

In another step along the precarious tightrope between Arctic resource development and Arctic environmental protection, on Aug. 13 Secretary of the Interior Ken Salazar announced the Bureau of Land Management's selection of a preferred alternative for the integrated activity plan for the National Petroleum Reserve-Alaska, or NPR-A. The preferred option — known as alternative B-2 — consists of the highest environmental protection option of four alternatives presented in BLM's draft plan for the reserve, but with reductions in the sizes of some special areas designated for environmental protection and with no recommendations for wild and scenic river designations.

ALAN BAILEY

KEN SALAZAR

Salazar said that Interior had received 400,000 comments on the draft plan and associated environmental impact statement, issued in the spring.

This is the first time that Interior has attempted to develop an activity plan for the entire NPR-A — previously the agency has issued individual plans for different parts of the reserve.

11.8 million acres

The newly announced preferred alternative would make about 11.8 million acres of NPR-A available

see **NPR-A PLAN** page 18

GOVERNMENT

Corps' moving target

Alaska leaders decry potential for further permitting delay on Point Thomson

By WESLEY LOY
For Petroleum News

The U.S. Army Corps of Engineers says more time might be needed to decide on a permit for ExxonMobil's proposed Point Thomson development on Alaska's North Slope.

Since late 2009, the Corps has been considering ExxonMobil's application for a dredge and fill permit to construct a natural gas condensate development at remote Point Thomson, located about 60 miles east of Prudhoe Bay.

On Aug. 14, the Corps issued a statement on the status of the permit.

The Corps said it remains hopeful it can render a "record of decision" on the permit application by its target date of Sept. 21. However, the timing could change, the agency said.

"The target dates are estimated dates only and are established based on the volume and complexity of information we are reviewing in order to make a decision to ensure we are approving the

While the Army Corps is the lead permitting agency for Point Thomson, two other federal agencies have been providing input — the Fish and Wildlife Service and the Environmental Protection Agency.

see **MOVING TARGET** page 15

EXPLORATION & PRODUCTION

Linc ready for big year

Australian company planning 5 Umiat wells, 3 underground coal gasification wells

By ERIC LIDJI
For Petroleum News

When Linc Energy (Alaska) Inc. makes its second attempt to explore the Umiat oil field this winter, its program will be slightly larger than what it originally laid out last year.

The local subsidiary of an Australian independent still plans to drill as many as five wells this winter at the prospect in the Brooks Range foothills, but in addition to drilling, testing, coring and reservoir analysis, it now also plans to conduct a horizontal well test.

And Linc has set an "aggressive timeline" to bring Umiat online in five to seven years.

The Umiat work comes in addition underground coal gasification exploration in the Cook Inlet and Interior regions and a conventional gas exploration program in Cook Inlet.

Umiat viable without road

After acquiring the Umiat prospect in June 2011, Linc announced its intentions to conduct a multi-well exploration program at the field at the next winter drilling season.

With the onset of winter, though, Linc decided low snow levels in the foothills affected its ability to build a snow road. A snow or ice road is crucial for accessing the remote prospect, some 80 miles west of the trans-Alaska oil pipeline and Dalton

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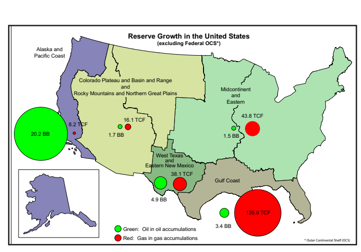
Thinks 32 billion barrels of oil reserves could potentially be added to conventional fields across the entire United States



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Construction work near complete in July; base gas fill delayed because contracted gas not delivered, more sought from producers

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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

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Milne Point MPU-S35	BP
Dreco 1000 UE	16 (SCR/TD)	Milne Point MPE-11	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD1-22b	ConocoPhillips
AC Mobile	25	Prudhoe Bay Y-19A	BP
OIME 2000	141 (SCR/TD)	Kuparuk 1B-18	ConocoPhillips
Kuukpik	5	Demobilizing by barge from Barrow	North Slope Borough
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 3N-11A	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
Dreco 1000 UE	7-ES (SCR/TD)	Stacked out	Available
Dreco 1000 UE	9-ES (SCR/TD)	Stacked out	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	Available
Academy AC electric Heli-Rig	105-E (SCR-TD)	Prudhoe Bay ALCOR1	Great Bear Petroleum

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

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site C-09B	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site S-07	BP
Ideco 900	3 (SCR/TD)	Kuparuk Well 2T-218	ConocoPhillips
Parker Drilling Arctic Operating Inc.			
NOV ADS-10SD	272	Prudhoe Bay final construction and commission	BP
NOV ADS-10SD	273	started acceptance testing on Aug. 2, scheduled to complete Aug. 11	BP

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP			
Top drive, supersized	Liberty rig	Inactive	BP
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODSN-27I	Pioneer Natural Resources
OIME 2000	245-E	Oliktok Point OI20-07	ENI
Oilwell 2000	33-E	Prudhoe Bay Stacked out	Available
Doyon Drilling			
Sky Top Brewster NE-12	15(SCR/TD)	Spy Island S125-N2	ENI

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Swanson River, assorted workovers	Hilcorp Alaska LLC
Cook Inlet Energy			
Atlas Copco RD20 34		Finalizing Otter Project west side of Beluga River Field	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Beluga BRU 244-23	ConocoPhillips
Taylor	Glacier 1	Stacked Marathon Yard	Kenai Land Ventures working for Buccaneer
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked	Available
Rigmaster 850	129	Kenai Stacked out	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Being mobilized from Deadhorse to Kenai for Tiger Eye Project	NordAq

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
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	Furie
Cook Inlet Energy			
National 1320	35	Being assembled Osprey platform	Cook Inlet Energy
Hilcorp Alaska LLC (Kuukpik, labor contract)			
	428	Anna Platform, Completed Turbine test, demobilized Crews	Hilcorp Alaska LLC
		Steelhead Platform Well M-31, Redrill	Hilcorp Alaska LLC
		Monopod Platform preparing to do rig refurb work	Hilcorp Alaska LLC

Mackenzie Rig Status

Canadian Beaufort Sea

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
SDC Drilling Inc.			
SSDC CANMAR Island Rig #2	SDC	Set down at Roland Bay	Available

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Still out of the NWT, but is again available	Available

The Alaska - Mackenzie Rig Report as of August 13, 2012. 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*

	Aug. 10	Aug. 3	Year Ago
US	1,931	1,930	1,959
Canada	299	303	464
Gulf	48	46	35

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

● EXPLORATION & PRODUCTION

Furie moving to next Kitchen Lights well

Stops drilling of Kitchen Lights Unit No. 1 well at total depth of 15,298 feet; still analyzing this year's drilling results

By ALAN BAILEY
Petroleum News

Furie Operating Alaska has reached a total depth 15,298 feet with its Kitchen Lights Unit No. 1 well, drilled from the Spartan 151 jack-up drilling platform in Alaska's Cook Inlet, and is now planning to move the platform to the drill site for the Kitchen Lights No. 2 well by mid-August, Furie President Damon Kade told Petroleum News in an Aug. 9 email. The company plans to spud Kitchen Lights No. 2 by late August and then drill, evaluate and suspend the well by late October, Kade said.

Started last year

Furie started drilling the No. 1 well in 2011, reaching a depth 8,805 feet before halting the drilling for the winter. The company reported a natural gas find with probable reserves of 750 billion cubic feet. The company re-entered the well earlier this summer to complete the drilling.

Damon declined to comment on what Furie has found from this year's drilling of the well — the company is still analyzing the results of the well logging, he said. However, he confirmed that the well had not drilled into the pre-Tertiary rocks of the basin.

Meantime, with an acute need for new natural gas supplies in Southcentral Alaska, Furie wants to move ahead to develop the gas find that it made in the Kitchen Lights Unit No. 1 well last year. The company plans to install an offshore monopod platform in 2013 — the company has completed the initial platform design, Kade said.

In March Alaska's Division of Oil and Gas granted Furie an extension of the term of the Kitchen Lights Unit to Jan. 31, 2016 — the unit had originally been due to expire on Jan. 31 of this year.

Pre-Tertiary

Kade has previously said that Furie wants to drill both of its Kitchen Lights Unit wells into the pre-Tertiary.

The state has offered a tax credit of up to $25 million to the first company to drill into the pre-Tertiary from a jack-up rig. The term "pre-Tertiary" essentially refers to strata of the Mesozoic era, including rocks of Jurassic age that source the oil in the Cook Inlet oil fields. The Mesozoic strata lie beneath the sequence of Tertiary strata that host the producing Cook Inlet oil and gas fields: For many years there

see **FURIE** *page 5*

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CORRECTIONS

Linc did not acquire CIRI acreage

An article in the July 29, 2012, issue of Petroleum News ("Linc refines portfolio") incorrectly noted that Linc Energy (Alaska) Inc. holds lease acreage from Cook Inlet Region Inc. in Alaska. While CIRI leases were originally mentioned among the assets Linc would obtain when it acquired the Cook Inlet holdings of the San Francisco-based GeoPetro Resources Co. in March 2010, CIRI ultimately did not approve the transfer.

Petroleum News regrets the error.

Healy announcement Aug. 6

The article titled "Research teams head to Chukchi Sea" on page 5 of the Aug. 12 issue of Petroleum News incorrectly stated that the Bureau of Ocean Energy Management made an announcement on Nov. 6 about a team of scientists leaving Dutch Harbor on the icebreaker Healy on a three-week study of marine life in the Hanna Shoal area of the Chukchi Sea. The announcement was made on Aug. 6, not Nov. 6.

FINANCE & ECONOMY

State gauging interest in RIK oil

With the current Flint Hills contract set to expire in early 2014 the state wants to know if any petroleum processors want to buy

By ERIC LIDJI
For Petroleum News

The state is looking for someone to buy its oil.

The Alaska Department of Natural Resources wants to know if any commercial petroleum processors with good credit are interested in bidding for some or all of its North Slope royalty in-kind oil supply when the current contract expires in early 2014.

After receiving an inquiry from a potential buyer, the state is now soliciting oil refineries in the state and on the West Coast, and the major North Slope producers. State statute requires the natural resources commissioner to either hold a competitive sale for royalty in-kind oil, or determine the best interest of the state can be met without such a sale.

Although one potential benefit of buying royalty in-kind is the possibility of beating the market price, Banks said the state is aiming to sell the oil at a price equivalent to its royalty in-value, plus bonus bids and special commitments.

The informal solicitation could lead to a competitive sale sometime soon.

If the state holds an auction, it would be the first for North Slope oil since 1984, according to Kevin Banks, a petroleum market analyst with the Division of Oil and Gas.

Through its lease terms, Alaska gets a cut of all oil produced in the state, but it can choose to take its share either in dollars (royalty in value) or in actual barrels (royalty in kind). State statute places a preference on claiming royalty in-kind whenever possible because the state can potentially earn more by selling oil directly on the open market.

Although one potential benefit of buying royalty in-kind is the possibility of beating the market price, Banks said the state is aiming to sell the oil at a price equivalent to its royalty in-value, plus bonus bids and special commitments. The stability of supply provides an incentive for buying from the state over other potential suppliers, he said.

The state asked companies to respond by the end of the month.

Special commitments required

The state is currently selling its North Slope royalty in-kind oil to Flint Hills Resources LLC for its North Pole refinery, under a 10-year contract set to expire March 31, 2014.

The current effort would use that contract as a model.

After a failed effort to sell its royalty in-kind oil to untraditional investors in the early 1980s, the state began focusing its sales pitch on commercial petroleum processors.

Throughout the 1980s and 1990s, the state also required a letter of credit from potential buyers. It relaxed the provision some for Flint Hills, requiring instead a financial guarantee from its parent company, Koch Industries Inc., and regular financial analyses.

While the royalty in-kind contract historically includes provisions to process a certain amount of oil in Alaska and to hire locally — to the extent the state can legally compel a company to do so, the Flint Hills contract started the process of "special commitments" to ease consumer fuel prices in Alaska and to increase the supply of crude oil for local use.

Ideas originate from the bidder. The 2004 Flint Hills contract included commitments to use the Alaska Railroad, to promote the Fairbanks International Airport and to maintain parity for gasoline prices between Fairbanks and Anchorage, among other commitments.

"It'll be interesting to see what people propose," Banks said. ●

Contact Eric Lidji at ericlidji@mac.com

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FURIE

has been speculation about the possibility of finding new oil resources in Mesozoic reservoirs in the basin, although the relatively high cost of deep drilling into the Mesozoic has deterred explorers from doing so.

Under the relevant state statute, the determination of who first drills into the Mesozoic, and hence qualifies for the tax credit, will be made based on when the drilling of the well starts at the seafloor, rather than on when the drill bit penetrates Mesozoic rocks. There are additional, smaller credits available to the second and third companies to drill into the pre-Tertiary using a jack-up rig.

Australian independent Buccaneer Energy Ltd. is in the process of bringing its jack-up rig to Cook Inlet, with plans to drill up to two wells in the inlet this year. ●

Contact Alan Bailey at abailey@petroleumnews.com

FINANCE & ECONOMY

Buccaneer closes on Cosmopolitan

Buccaneer Energy Ltd. and BlueCrest Energy Inc. have closed on their acquisition of the Cosmopolitan prospect in the Cook Inlet basin, the companies said Aug. 16.

Through their deal with Pioneer Natural Resources Alaska Inc., the Australian independent Buccaneer acquired a 25 percent working interest in the offshore prospect and assumed operatorship over exploration and development efforts, and the Fort Worth, Texas-based privately held BlueCrest acquired the majority 75 percent working interest.

Buccaneer said the closing documents are being held in escrow while its lender, Richmond Hill Investment Co. LP, "provides final written consents in respect to Buccaneer assuming the role of operator." That is expected before the end of August.

The Cosmopolitan prospect consists of two leases in the waters off the coast of Anchor Point, in the southern Kenai Peninsula. Pennzoil discovered Cosmopolitan in 1967, but the field remained fallow until ConocoPhillips resumed exploration efforts in 2001.

ConocoPhillips drilled a well and a sidetrack and shot 3-D seismic over the region before selling the prospect to Pioneer in 2006. Pioneer drilled a lateral off the sidetrack and conducted a subsequent flow test, but decided not to pursue full-scale development.

Buccaneer plans to use its newly acquired jack-up rig to conduct shallow gas drilling from offshore. The company also plans directional wells from an onshore pad to target deeper oil deposits.

—ERIC LIDJI

● ALTERNATIVE ENERGY

TATEC continues under preliminary permit

Company has withdrawn preliminary application, notice of intent; working on details for study plans for Turnagain tidal project

By KRISTEN NELSON
Petroleum News

Turnagain Arm Tidal Energy Corp., TATEC, which is proposing a tidal power project in Southcentral Alaska's Cook Inlet, has withdrawn its preliminary application document, PAD, and notice of intent, NOI, and is focusing on details required for study plan submission.

The project is still under study, but is moving forward more slowly than TATEC President Dominic S.F. Lee envisioned a year ago when staff from the Federal Energy Regulatory Commission were in Anchorage for scoping meetings on the project.

The project holds a preliminary permit which it received in February 2010 and TATEC told FERC in February that it plans to resubmit the NOI and PAD later this year.

In a Feb. 14 letter to FERC Lee said the PAD and NOI were being withdrawn because the company's study teams did not have enough time to revise the 14 study plans FERC and state and federal agencies required in the 30 days allowed.

FERC said in a Feb. 15 response that if TATEC moves forward with a license application it may refile its NOI and PAD but noted that the three-year term and requirements of the 2010 preliminary permit are unchanged.

240 megawatts

FERC representatives were in Anchorage last August for scoping meetings on the proposal, which would produce 240 megawatts of tidal-generated energy from turbines in Turnagain Arm.

The turbines would be backed by a water reservoir 1 mile by 2 miles in diameter which would store water for use during slack tides. Lee said at the August FERC scoping meeting that the plan is based on a tidal power project in La Rance, France, which has been in operation since 1966. The TATEC proposal would use a "bulb type of turbine" with a barrage 1,000 feet long and 100 feet wide located 5 miles from Possession Point near Fire Island. The estimated construction cost is $760 million.

The reservoir backing the barrage, a concrete wall surrounded by rock with a height of 20 feet above high tide, would store water for use during slack tide. A submerged cable would run onshore to a switch yard in Anchorage and onshore to a control building on Point Possession at the northern end of the Kenai Peninsula.

Progress to date

Lee told FERC in his Feb. 14 letter that the withdrawal was requested because of the time required for revision of study plans.

"As has been noted by agencies and stakeholders, the project is a new project that involves some unique features; is complex; and requires a large number of baseline studies in an area where little information exists," he said. Lee said the company believes its Turnagain Arm studies, and its studies on developing tidal energy, "are worth the expenditure of more time and resources and will be of benefit to many."

Lee told FERC in February that TATEC would work on "more specific engineering plans for the tidal plant and transmission lines" as well as working on detailed study plans.

In a July update on the project Lee told FERC "TATEC engineers have worked on detailed engineering design on how the offshore storage reservoir and the tidal turbine plant interface" and said a new design was discussed with outside engineers and hydrologists and "computer modeling will be needed to verify mathematically the sizing of the turbines' casing, water conduits, slot gates, and the reservoir."

TATEC also has applied to the Alaska Department of Natural Resources for a land lease and land use permit for the project area. Lee said that while a land lease wouldn't be issued until the project was ready for construction, a land use permit is required for activities in the project area. ●

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LAND & LEASING

State expands North Fork gas pool PA

Nearly two months after approving an expansion of the North Fork unit, the state has also approved an expansion of the Gas Pool No. 1 participating area in the Cook Inlet unit.

The expansion increases the participating area to 800 acres. When operator Armstrong Cook Inlet LLC requested an expansion of both the unit and the participating area in January 2012, it asked the state to increase the 640-acre participating area to some 2,600 acres. The revision includes a contraction of the original participating area at its northeast corner and an expansion on its western edge, though not as large as Armstrong requested.

Under state regulations, the boundaries of a participating area must be limited to an area believed to be "capable of producing or contributing to the production of hydrocarbons in paying quantities," as determined by geological, geophysical and engineering data. The state approved the expansion retroactive to March 1, 2011.

—ERIC LIDJI

● ALTERNATIVE ENERGY

Modern technology drives old plan

Utilities behind proposal to use North Slope natural gas for electricity, move power through HVDC, with 'light' HVDC spur lines

By KRISTEN NELSON

Petroleum News

An idea pursued by ARCO in the 1980s and early 1990s has been revived due to a combination of modern technology and the current surplus of natural gas.

It would use North Slope natural gas to produce electricity and then use that electricity to power the state — not just the Railbelt but also rural Alaska.

Meera Kohler, president and CEO of Alaska Village Electric Cooperative and Robert Jacobsen, Ph.D., vice president, science and technology for Marsh Creek LLC, rolled out a proposal in July to the Commonwealth North energy task force.

Since then, the two have given several presentations, including one to legislators Aug. 14 and one to the Regulatory Commission of Alaska Aug. 15.

Jacobsen has a long history with high voltage direct current, or HVDC.

He told legislators and later the RCA commissioners that ARCO was run by engineers in the 1980s and they didn't believe it would be economic to move natural gas off the North Slope via pipeline. ARCO established ARCO Power Technologies to look at high-voltage direct current as a way to use natural gas on the North Slope and move energy to market.

ARCO Power Technologies did the studies and determined you could take some 8 gigawatts of power to California and put it into the U.S. power grid at competitive prices.

What happened?

The political climate in Alaska favored a natural gas pipeline and ARCO didn't want to get at cross purposes with Alaska's government, so "they just canned" the idea, Jacobsen said.

What's different?

Kohler, who's been in the electric industry in Alaska since 1979, and is also a member of the Commonwealth North board of directors, co-chaired a Commonwealth North taskforce looking for energy answers for Alaska.

Their report, "Energy for a sustainable Alaska: The rural conundrum," came out in February.

The challenge, Kohler told legislators, was what it cost Alaskans, particularly rural Alaskans, to heat their homes. And that cost has been steadily rising, she said, noting that 10 years ago AVEC's average delivered fuel cost was $1.29 per gallon. The 2011 average, $4.27 a gallon, was an increase of $2.98, or 331 percent.

Findings of the Commonwealth North study included a need to reduce rural dependence on diesel fuel and to interconnect rural communities into regional electrical transmission grids to develop economies of scale.

In mid-July, Kohler and Jacobsen rolled out a proposal at Commonwealth North to generate electricity on the North Slope and send it by high-voltage direct current, HVDC, to Railbelt communities and by what Jacobsen called "HVDC light" to rural communities.

Stranded gas

A premise of Jacobsen's presentation is that Alaska has vast supplies of cheap energy — natural gas which is stranded on the North Slope by plentiful Lower 48 supplies of gas currently being developed, and available to be developed worldwide.

Conventional HVDC is used to "take massive amounts of power long ways," he said.

The transmission lines are much cheaper than AC, or alternating current, lines.

"The expensive part is the beginning and the ending, the converter stations which take the AC generation, put it onto the line and then take it off and put it into the grid," Jacobsen said.

Because of those costs, HVDC isn't economic for distances under 300 miles "if you just look at the economics." But, Jacobsen said, considering the environmental and right-of-way issues that come up today, "it actually becomes economic well under 300 miles."

In the late 1990s a focus developed on pulling power off HVDC lines for communities along the lines, and by the late 1990s and early 2000s, Jacobsen said, technology for tapping off "small blocks of power into various areas" was becoming a reality.

Another important technology is combined cycle gas turbine generation, enabling electrical generation from natural gas with just over 60 percent efficiency, he said.

Costs and benefits

Jacobsen presented rough costs for two projects — energizing the Railbelt and taking power to the Lower 48 — and described a third proposal, energizing rural Alaska.

He said a Railbelt HVDC system would cost some $3.71 billion (a 1 gigawatt power plant, HVDC power line and converter stations) and with operating costs would deliver power at about 9.3 cents per kilowatt hour.

A larger system to take power to market in the Lower 48 would have capital costs of almost $20 billion, including a 6.4 gigawatt power plant, and with operating costs produce power at about 7.4 cents a kilowatt hour.

Jacobsen did not have costs for a plan which would energize Alaska, because of unknown costs for spur lines, but said it would involve a 5 gigawatt power plant. "HVDC light is on the cusp of becoming economic for providing heat and power to these remote communities," he said.

Asked about the efficiency of electricity, Jacobsen said that while with diesel 80 percent goes to heat while 20 percent is lost, with electricity generated at 60 percent efficiency and a 4.5 percent transmission loss to Fairbanks, "you actually are getting 55 percent of the available energy ... in the house vs. the 80 percent which ends up in the house from burning the oil. But since the gas is so much cheaper than the oil, you are way ahead in the cost of providing heat."

What we're advocating, Jacobsen said, is using stranded gas to power Alaska's energy infrastructure and to benefit all Alaskans with electrical power providing heat and cheap power fueling economic growth, "and we ship 'made in Alaska,' not pieces of Alaska in barrels or in cargo ships. ... And the most important thing is it provides lots of good jobs," he said.

State's role

Jacobsen said the state would need to play a role in negotiating long-term gas contract pricing, but he said the next step would be a more detailed study that addresses not only the line south from the North Slope to Anchorage "but the spurs running out to the various villages and remote communities, establishing the most concrete and cost-effective technologies, and at which point you break down into AC distribution grids."

Kohler said that they've been taking the presentation to various entities and said she thinks some of the larger regional Native corporations would have an interest. She said one question was how to keep the project public, based on the concept of a generation and transmission co-op, the model used in the Lower 48.

The challenge for the utilities, she said, is that "all of us rolled together do not have the credit capacity to take on a project of this size."

Kohler said the plan was to ask the Legislature for $2-to-$3 million to further studies on the proposal. ●

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NATURAL GAS

Australia makes bold move as LNG supplier

3 LNG plants in operation, 7 more under way; first floating LNG project approved; country will go from 4th to 2nd largest producer

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

The U.S. shale gas boom has scored big headlines in the world of natural gas.

The boom has shattered old understandings of gas pricing, galvanized environmentalists, ignited a national debate over exporting resources, wounded Canadian gas producers, surprised LNG makers in Qatar and elsewhere whose target U.S. market vanished, and sparked a global scramble as countries assess their own shale prospects.

The Pluto plant opened this year and is Australia's third LNG plant.

BILL WHITE

But almost as breathtaking is Australia's major move into liquefied natural gas production.

Australia's third LNG plant sent its first shipment to market in June.

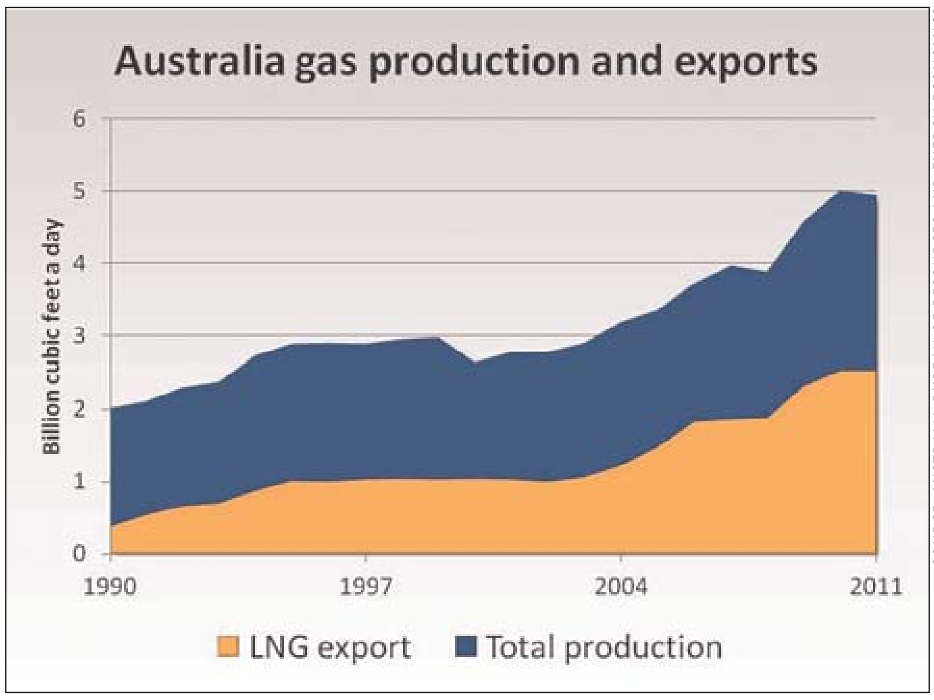
The country's seven other LNG projects under way today total a stunning $170 billion worth of development.

Even that lofty figure understates the extent to which Australia's natural gas industry is mushrooming — it doesn't count billions of dollars in gas-field expansions, gas-pipeline construction and gas-fired power plant building that also are afoot. And it omits the roughly dozen other LNG projects in various stages of consideration.

Australia is expanding the boundaries that define what an LNG project can be.

The world's first floating LNG project has been sanctioned in Australia involving a massive typhoon-resistant factory ship anchored 125 miles at sea over a remote gas field. The 1,600-foot-long ship being built in South Korea for Shell will cover an area the size of 24 football fields.

Australia also is building the first LNG projects fed by coal-bed methane rather than conventional natural gas. Three such projects are proceeding, with more under discussion.



1 2 SERIES

Fully two-thirds of global LNG capacity under construction is in Australia.

The country is poised to leap from the world's No. 4 LNG producer last year to No. 2 within a few years. Many predict Australia will be LNG's top dog later this decade, dethroning Qatar, which underwent its own audacious tripling of its LNG capacity during the past five years.

In short, Australia is poised to stake its claim to the LNG marketplace that backers of a major Alaska LNG export project and several along the Gulf of Mexico coast want to enter.

133 tcf of proved reserves

Like Alaska, Australia has far more gas than it can consume internally. A conservative estimate of 133 trillion cubic feet of proved reserves is 150 years worth of gas at Australia's current domestic consumption, according to figures from the 2012 BP Statistical Review of World Energy.

Like Alaska, Australia's oil and gas era started with discoveries in the 1950s and 1960s and saw rapid build-out through the 1970s. Like Alaska, oil was easier to bring to market than natural gas, with many remote gas discoveries stranded for decades.

Like Alaska, interest in natural gas development revived in the late 1990s and early 2000s in response to higher prices.

But here the paths diverge.

Australia eyed growing LNG demand, especially in East Asia, and launched a gas-drilling renaissance that discovered dozens of new fields. Big, deep-pocketed western oil companies got involved — Shell, Chevron, ConocoPhillips, ExxonMobil, Total. Gas and electric utilities in Japan and elsewhere joined in.

In some cases, projects won rapid-fire board of director approval. Developers of Pluto LNG in Northwest Australia, which started up this year, committed to the $15 billion project just two years after the field was discovered. For the $10 billion-plus Prelude project being developed entirely offshore, approval came a mere four years after finding the anchor gas field.

Big paydays

Australia's mad dash into LNG has come with growing pains.

Many projects are late. Some are over budget. Skilled labor shortages are acute as so many big-ticket projects compete for engineers and heavy-equipment operators.

The Pluto LNG plant opened this year 18 months behind schedule and cost $14.9 billion, compared with its original budget of $12 billion.

The Gladstone project expected to open in 2015 was recently repriced at $18.5 billion, up from $16 billion. The cost of the nearby Queensland Curtis project set to start up in 2014 recently grew to $20.4 billion from the $15 billion estimate only two years ago.

Aggravating and possibly helping to explain these challenges is that LNG isn't Australia's only export industry undergoing a growth spurt. Coal and iron-ore mining are much bigger industries in Australia than natural gas, and both are amid their own multibillion-dollar expansions, competing with LNG projects for labor and equipment.

A government official last fall noted the financial boon that's blessed workers willing to relocate to far-flung job sites.

Alan Copeland of the Bureau of Resources and Energy Economics said a run-of-the-mill laborer on a remote LNG project is pulling in wages of $225,000 to $300,000 a year.

Some remote projects can entail housing thousands of workers in or near towns that previously boasted only a few hundred residents.

Environmental issues

Environmental issues are popping up, too. A $40 billion to $50 billion possible development called Browse in Northwest Australia would pipe gas over 200 miles from the offshore gas and liquids fields to an LNG plant that would be built near an environmentally sensitive and culturally important site called James Price Point. Among the issues: Avoiding fossilized dinosaur footprints that track along the coastline. Some traditional landowners greeted with disdain a 2011 agreement with the Aboriginal group Goolarabooloo Jabirr Jabirr designed to help push the project ahead.

Disposal of carbon dioxide, a waste greenhouse gas produced with methane and gas liquids, is an issue for some projects, just as it will be when Alaska's Prudhoe Bay gas reserves get developed. Sponsors of the $37 billion Gorgon project offshore Northwest Australia plan to reinject the CO2 and gave the project their OK only after the government accepted long-term liability for the carbon dioxide after it's injected.

In the more thickly populated east, coal-bed methane — called coal-seam gas thereabouts — will fuel the three LNG projects under way.

But the astounding abundance of coal-bed gas — the government estimates 30 trillion cubic feet clustered in Queensland, more than the conventional-gas reserves at Alaska's Prudhoe Bay — could boomerang on Australia's ambitions to add even more LNG projects.

Coal-bed wells are more closely spaced and less productive than conventional-gas wells. More wells mean more water use during production. This has riled farmers, who object to the number of wells, the amount of water needed and wastewater disposal plans.

Others warn of disaster as more LNG tankers sail past the Great Barrier Reef en route between Gladstone, the east-coast port that will house all three coal-bed

see AUSTRALIA LNG page 9

continued from page 8

AUSTRALIA LNG

methane LNG plants under development, and customers in Japan, China and elsewhere in Asia.

Some expect a furor if east coast consumers get whacked with higher natural gas prices thanks to exports. LNG will be sold to Asian buyers paying oil-indexed prices, not the currently lower domestic gas prices in Australia. Will coal-bed methane producers start routing their gas to the highest bidder, inflating local prices?

Another problem is that coal-bed field development to support the three LNG projects is behind schedule. Thank Mother Nature in part for that. Construction started during two of Queensland's wettest years in decades — 2010 and 2011. The ground was so sodden developers couldn't access some top prospects.

Reuters recently noted the problems could delay or kill plans for more coal-bed methane LNG plants beyond the three under development today: "Patchy drilling results, rising costs and a world-wide glut of gas threaten to jeopardize what could amount to more than $60 billion of additional investment in liquefied natural gas (LNG) plants, based on current project costs, and leave an industry that would be just half the size its architects once envisaged.

"Instead of exporting 56 million tonnes (metric tons) of LNG a year, as originally planned, the industry may have to stop at 25 million tonnes — the capacity already being built on Australia's northeast coast."

One analyst told Reuters: "'If you join up all these dots: rising costs, technical challenges, regulatory hurdles and push-back from competing communities ... then you have a very poor scenario there.'"

Seven plants in five years

LNG plants under development

■ Australia Pacific

$20 billion; 415 billion cubic feet a year capacity

■ Gladstone

$18.5 billion; 380 billion cubic feet a year capacity

■ Gorgon

About $40 billion; 730 billion cubic feet a year capacity

■ Ichthys

$34 billion; 410 billion cubic feet a year capacity

■ Prelude

$10 billion-plus; 175 billion cubic feet a year capacity

■ Queensland Curtis Island

$20 billion; 415 billion cubic feet a year capacity

■ Wheatstone

$29 billion; 430 billion cubic feet a year capacity

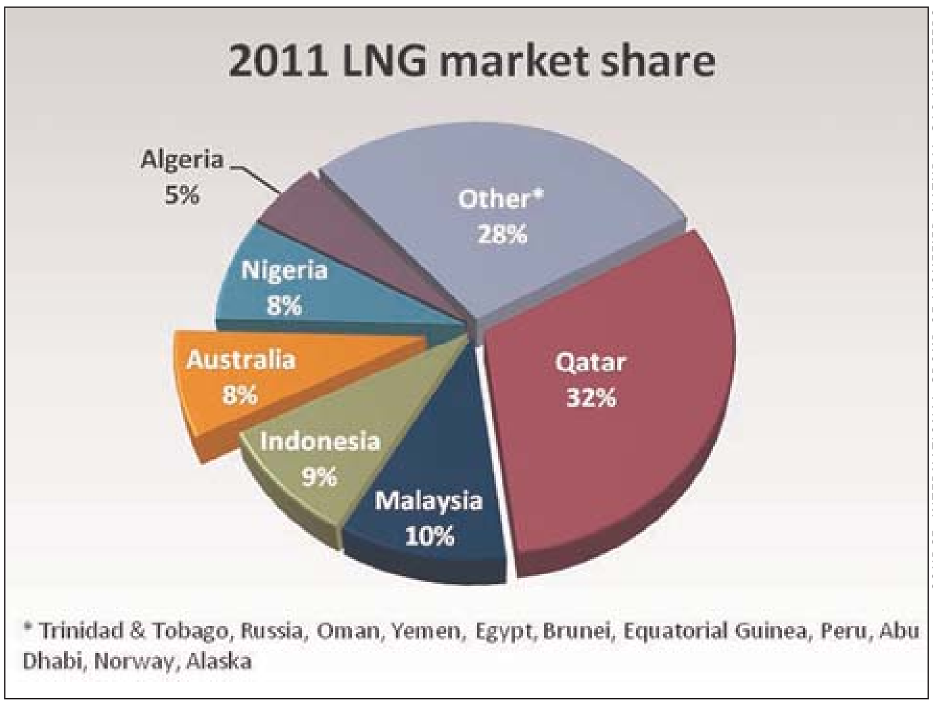
Despite the challenges facing Australia's LNG industry, seven new plants are forecast to be finished within five years.

These plants should have enough capacity to make 60 million metric tons of LNG annually — an average of 8 billion cubic feet of gas per day. That's roughly three times more gas than a large project to process Alaska North Slope gas might export.

By comparison, Australia's two existing plants ran full-throttle last year in making 19.5 million metric tons — 2.6 billion cubic feet a day on average. With the third plant — Pluto — now online, Australia's capacity is about 24 million metric tons.

This new capacity under construction could roughly keep world LNG supply on pace with or ahead of expected demand growth through 2017, according to several analyses.

Beyond that, it's a question mark whether Australia will surge past Qatar as the world's biggest LNG supplier by expanding production beyond 2017. (The seven projects will bring Australia's LNG capacity to roughly the same as Qatar's.)



SOURCE: INTERNATIONAL GROUP OF LIQUEFIED NATURAL GAS IMPORTERS

Australia will be a high-cost producer. Adding the cost of installing offshore fields and well as the LNG plants, Australia needs a high oil price to pay off the development costs. So far, oil-linked LNG prices have worked favorably for Australia.

But LNG plants in Alaska, the U.S. Gulf Coast or Canada might be more cost effective for serving the demand growth after 2017, according to one analysis. New discoveries off East Africa — totaling at least 100 trillion cubic feet of recoverable reserves — also could dash Australia's post-2017 LNG expansion hopes.

For now, Australia is playing a strong hand:

•It's rich in natural gas reserves.

•Developers face little risk the country will nationalize their gas fields or LNG plants.

•It's near the big LNG markets of Japan, South Korea, Taiwan, China and India.

•The country welcomes foreign investment, as it's demonstrated over the decades in its mining industry.

Beyond this, Australia has shown it can be relied on to deliver. It's hard to overstate the value of reliability to LNG importers such as Japan, South Korea and Taiwan. They need gas for power production and they have virtually no gas fields of their own.

Since Australian LNG production began in 1989 it has built a reputation as a reliable supplier.

This is part 1 of a story; part 2 will appear in the Aug. 26 issue.

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/australia-makes-bold-move-lng-supplier.

● NATURAL GAS

CINGSA short of base gas for facility

Construction work near complete in July; base gas fill delayed because contracted gas not delivered, more sought from producers

By KRISTEN NELSON

Petroleum News

Cook Inlet Natural Gas Storage Alaska, CINGSA, told the Regulatory Commission of Alaska Aug. 13 that it has not received the base gas it needs to ensure gas can be withdrawn by customers at optimum rates this coming winter.

The natural gas storage facility, designed to hold up to 11 billion cubic feet of working gas, officially began operations May 31.

CINGSA said that while the commission has closed the docket and progress reports are not required, it will continue to file monthly reports until the facility is fully operational.

The issue with base gas began in March 2011 when CINGSA contracted with an unnamed Cook Inlet producer to provide 3.24 bcf of base gas.

"Sufficient base gas is needed to ensure that pressures in the storage reservoir are high enough to permit customers to withdraw gas from the CINGSA Storage Project within design parameters," CINGSA told the commission.

The natural gas storage facility, designed to hold up to 11 billion cubic feet of working gas, officially began operations May 31.

However, the producer with which it contracted "now asserts that, under this agreement, it had the option to sell the base gas to CINGSA but not the obligation to do so," a contention with which CINGSA said it disagrees.

"CINGSA believes that gas intended to be sold to CINGSA has instead been exported to Japan as LNG at a substantially higher price than CINGSA had agreed to pay," it told the commission.

Withdrawal service available

CINGSA said it would be able to provide withdrawal service to customers even with lower levels of base gas, but believes 7 bcf of base gas "would allow the project to operate as designed."

CINGSA said it has secured 5 bcf of base gas, including 0.5 bcf of base gas under a July 11 contract with ConocoPhillips Alaska. Deliveries of that gas are expected beginning in August.

CINGSA said it is attempting to secure additional base gas "from various Cook Inlet area producers, so that gas can be withdrawn by customers from the CINGSA Storage Project at optimal rates during the 2012-13 winter heating season."

CINGSA said it is attempting to secure additional base gas "from various Cook Inlet area producers, so that gas can be withdrawn by customers from the CINGSA Storage Project at optimal rates during the 2012-13 winter heating season."

July work

Injection began April 1 and July injection rates ranged from about 25 million to 52 million cubic feet per day, "depending on customer nominations and the availability of base gas," CINGSA told the commission.

Subsurface engineering work during July included re-perforation of wells 2, 3, 4 and 5 to improve injection and withdrawal capability. All wells showed improved deliverability following the work, CINGSA told the commission; the same work is planned for well 1 as soon as a coiled tubing unit is available.

CINGSA said it has received one or two noise complaints from nearby residents and "is in the process of identifying and implementing sound attenuating devices to reduce noise levels further."

The compressor plant was idle during a scheduled shutdown of the Kenai Nikiski Pipeline and another round of sound level data was collected then, with some of the sampling focused on the area where residents had complained.

All station piping was completed in July, and with construction work completed in the month, CINGSA said surface facilities are approximately 93 percent complete.

The CINGSA owners are Semco Energy, MidAmerican Energy Holdings Co., Cook Inlet Region Inc. and First Alaska Capital Partners. ●

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RCA approves ownership changes

In an Aug. 14 decision the Regulatory Commission of Alaska approved the acquisition by AltaGas Ltd. and AltaGas Utility Holdings (U.S.) LLC of a controlling interest in Enstar Natural Gas Co., a division of Semco Energy Inc. and Alaska Pipeline Co., a wholly owned subsidiary of Semco.

A Feb. 1 agreement provided for acquisition by AltaGas U.S. of 100 percent of the outstanding shares of common stock of Semco Holding, which holds 100 percent of the outstanding shares of Semco, with AltaGas U.S. replacing Continental Energy Systems LLC as owner of Semco Holding and through Semco controlling Enstar and Alaska Pipeline Co.

In comments on the proposed sale the Municipality of Anchorage, doing business as Municipal Light & Power, told the commission that it is critical that an entity owning Enstar demonstrate willingness to commit resources necessary to meet the challenges of supplying and transporting natural in Southcentral Alaska and said the commission should require applicants to file five-year capital improvement plans for Enstar and commit to providing support to Enstar to participated with other utilities in coordinated gas supply planning efforts.

AltaGas told the commission it was fully aware of the challenges described in ML&P's comments and was willing to work cooperatively with Southcentral utilities to overcome those challenges, but said submission of a five-year plan at this stage was not practical. It said that upon approval of the sale it would see to it that Enstar and Alaska Pipeline Co. "continue to contribute their fair share to those important efforts."

AltaGas Ltd. is a Canadian company headquartered in Calgary, Alberta, common stock and preferred shares traded on the Toronto Stock Exchange. Through subsidiaries it provides retail natural gas service to some 115,000 customers in Alberta, British Columbia, Nova Scotia and the Northwest Territories.

AltaGas U.S. is a Delaware limited liability company formed in January for the purpose of holding AltaGas Ltd. utility investments in the U.S. and is wholly owned by AltaGas Ltd. The commission also approved acquisition by AltaGas of a controlling interest in Cook Inlet Natural Gas Storage Alaska LLC. Semco controls 65 percent of CINGSA through an indirect subsidiary.

—KRISTEN NELSON

● PIPELINES & DOWNSTREAM

Easement sought for Cook Inlet gas line

By WESLEY LOY
For Petroleum News

Cook Inlet Energy LLC is seeking a pipeline easement for its Otter natural gas prospect on the inlet's west side.

An Alaska Department of Natural Resources public notice about the easement application was published Aug. 10.

The application builds on some positive talk recently about Otter, where Cook Inlet Energy recently drilled an exploratory well.

The company is a subsidiary of Tennessee-based, publicly traded Miller Energy Resources Inc.

David Hall, Cook Inlet Energy's chief executive, said during Miller's July 25 investor conference call he had high hopes Otter will become "a very prolific gas field."

The Otter prospect is about 10 miles north of the Beluga River gas field, long a major energy source for Anchorage, the state's largest city.

Cook Inlet Energy recently drilled the Otter No. 1 well to a depth of 5,680 feet.

During the conference call, Hall said the well found "two significant hydrocarbon gas shows in the zone of interest." He said the company planned to conduct a chemical treatment, a hydraulic fracture or both to stimulate the well.

In its application to DNR, Cook Inlet Energy said the easement would be for a buried gas pipeline, 6 inches in diameter, to run alongside an existing road. The proposed easement would be 24,500 feet long and 30 feet wide, the public notice said.

A map shows the easement beginning at an existing gas line and running northwest along the south side of the Theodore River.

In an Aug. 15 interview, Hall told Petroleum News the easement application doesn't necessarily signify a commercial discovery at Otter.

"We're still wrapping our heads around what we have," he said.

The company intends to take its time and conduct a thorough analysis of the well results and the geology before making any definitive announcements, Hall said. He noted it's a new field, never before drilled.

That said, the company feels quite positive about Otter, he said, and applying for the pipeline easement is just part of the planning process.

The nearby ConocoPhillips-operated Beluga River field has been an important gas producer for many years. Chugach Electric Association operates a gas-fired power plant there.

Cook Inlet gas has been a hot topic in recent years, as known reserves are depleting and deliverability has become strained during winter when demand peaks.

As a result, drill bits have been turning to find new gas supplies.

Cook Inlet Energy used a company-owned rig to drill the Otter No. 1 well. A Miller Energy executive said the well cost about $7 million. ●

Contact Wesley Loy at wloy@petroleumnews.com

GOVERNMENT

DNR, NSB sign MOU on O&G permitting

Commissioner Dan Sullivan of the Alaska Department of Natural Resources and Mayor Charlotte Brower of the North Slope Borough signed a memorandum of understanding July 28 designed to coordinate authorization and permitting activities for North Slope oil and gas exploration and production.

The MOU states that the state and the NSB recognize the value of enhancing "collaboration, communication, and coordination in the review of exploration and development projects." Responsible resource develop benefits both the borough and the state, the MOU notes, while the related activities "create impacts which disproportionately affect local populations."

Companies involved in exploration and development are required to obtain a variety of permits and coordination among agencies reviewing applications or requesting information increases the effectiveness of authorizations and reduces the burden on applicants, the MOU says.

While DNR's Office of Project Management and Permitting "has demonstrated an ability to effectively coordinate this permitting and authorization activity across federal, state and local agencies," further coordination of regulatory activity between the borough and DNR may create additional benefits for the state, the borough and applicants.

The MOU also encourages DNR-borough cooperation "on issues of common interest that extend beyond efficient permitting and coordination."

Quarterly meetings

The MOU states that the DNR commissioner and the NSB mayor and/or representatives, will meet quarterly to discuss issues of concern with at least two of the meetings each year taking place in Barrow.

The NSB and DNR will encourage applicants to use Office of Project Management and Permitting processes, and to use pre-filing procedures "to identify issues early in the regulatory process."

To the extent possible, the MOU says, the borough and DNR will share information and data relevant to projects and coordination calls will be held at least monthly between OPMP and the NSB, with the mayor identifying departments of the borough to participate.

The director of the OPMP and the director of the NSB Department of Planning and Community Services will each identify personnel to participate in a working group which will discuss ways to further streamline approval of project activity "and avoid duplication of effort or other waste and inefficiency." The working group will report its findings to the directors.

—PETROLEUM NEWS

GOVERNMENT

Alberta-B.C. impasse persists

The rift between Alberta and British Columbia remains entrenched as the two provinces go their separate ways.

Alberta Premier Alison Redford was in Vancouver Aug. 14 speaking to a legal conference, but made no effort to meet with her B.C. counterpart Christy Clark to seek an end to their standoff over Enbridge's Northern Gateway pipeline, which Clark opposes unless her province is promised a bigger slice of revenues from the C$6 billion project.

ALISON REDFORD

The only olive branch extended by Redford was her concession that British Columbians were free to debate the merits of the controversial pipeline proposal.

"It is entirely appropriate for people in British Columbia to have a discussion with respect to whether or not (Northern Gateway) makes sense for them," she said.

But she told reporters, less than a two-minute walk from Clark's downtown Vancouver office, that the B.C. premier is not entitled to use Alberta's energy royalties as a bargaining chip.

Positions clear

"She made her position very clear (two weeks ago). Ours is very clear. Our positioned hasn't changed," Redford said.

"We believe it's very important for economic benefits to be spread across (Canada) and we don't believe that fundamentally changing Confederation (which gives provinces ownership and control over development of their natural resources) is appropriate."

Redford also left no doubt that she is pressing ahead with her goal of creating a national energy strategy, even if B.C. remains on the sidelines.

"We have every other premier across the country understanding the importance of the energy economy and understanding that it's important for all Canadians that we do work together," she said.

"It's important for all of us as political leaders to work together to ensure there is access to international markets and that there isn't any particular province that should get more access or less access to international markets based on geographical location," she said.

Redford did not rule out future talks with Clark, saying "I'm sure at some point in the future another discussion will take place."

—GARY PARK

STEVE SUTHERLIN

The Spartan 151 rig

● FINANCE & ECONOMY

Furie fights $15M Jones Act penalty

Cook Inlet driller calls fine excessive; suit says foreign ship used because US fleet couldn't carry rig around South America

By WESLEY LOY
For Petroleum News

Furie Operating Alaska LLC is suing the U.S. Department of Homeland Security to challenge a $15 million fine the company calls "unwarranted and unprecedented."

The 39-page suit, filed Aug. 7 in federal court in Anchorage, concerns the ocean transport of a jack-up drilling rig to Alaska's Cook Inlet in 2011.

Furie, headquartered in League City, Texas, is using the rig to drill exploratory natural gas wells in its offshore Kitchen Lights unit.

On Oct. 13, 2011, U.S. Customs and Border Protection, an agency within Homeland Security, sent Escopeta Oil Company LLC a notice assessing a $15 million penalty for a violation of the Jones Act. Furie acquired Escopeta in 2011.

The notice said a "nonqualified vessel" was used to transport the Spartan 151 rig. The $15 million fine corresponded to the agency's determination of the rig's value.

The Jones Act requires that cargo transported between domestic ports be done with U.S.-made ships, owned and crewed by American citizens.

The lawsuit says Furie has made several attempts to appeal the fine or negotiate a lower penalty, but to no avail.

Arbitrary and unconstitutional

Furie assets that, to its knowledge, the $15 million is the largest penalty ever assessed for an alleged Jones Act violation.

A foreign-flag, heavy-lift vessel was use the haul the rig part of the way to Alaska because no suitable U.S. vessels were available, the suit says.

The company asks the court to squash the fine on several grounds, including that it is arbitrary and capricious, and that it violates the "excessive fines" clause of the Eighth Amendment to the U.S. Constitution.

Furie also argues that the rig was not "merchandise" as defined in the law, and therefore no Jones Act violation occurred.

One of the suit's main points is that, in 2006, the Homeland Security secretary at the time, Michael Chertoff, granted the company a Jones Act waiver to transport a different jack-up rig, the Tellus, to Alaska on a different foreign ship.

The waiver was based on the importance of energy to national security, the suit says. Southcentral Alaska was, and is, facing a natural gas shortage, and the region is home to the strategically important Joint Base Elmendorf-Richardson and the Anchorage international airport.

As it turned out, the company never brought the Tellus to Alaska, as problems developed with that rig.

Furie's argument is that the facts supporting the 2006 waiver hadn't changed, yet Napolitano and other officials within Homeland Security refused to reconfirm the 2006 waiver or grant a new one.

The journey begins

The suit describes the company's attempts to gain a clear OK to haul the rig to Alaska, even as the long voyage unfolded. Furie was fearful the government might seize the rig.

On March 18, 2011, the rig departed a

see FURIE LAWSUIT page 13

● FINANCE & ECONOMY

BP asking up to $7.9 billion for Gulf fields

ASSOCIATED PRESS

BP PLC is asking for up to $7.9 billion for some of its oilfields in the Gulf of Mexico as it continues to sell assets after the 2010 oil spill, according to Bloomberg News.

According to the report Aug. 14, which cited two people with knowledge of the matter, BP could clear up to $5 billion to $6 billion after the buyer pays taxes.

BP declined to comment on financial terms of a sale but said that it intends to remain the largest oil and natural gas producer in the Gulf.

"No one should confuse our effort to sell these older, non-strategic assets, which we announced months ago, with our ongoing commitment to the Gulf of Mexico," said spokesman Brett Clanton. He said BP still plans to invest at least $4 billion per year over the next decade in the Gulf.

The company has six rigs in the Gulf now and plans to have eight by the end of the year, an all-time high.

Shares of BP rose 18 cents to $42.27 in afternoon trading.

London-based BP hopes to sell $38 billion worth of assets by the end of 2013 to help pay the costs of cleaning up the Gulf oil spill.

On Aug. 13, BP announced it agreed to sell a refinery in Carson, Calif., and pipelines and ARCO-branded gasoline stations to Tesoro Corp. for $2.5 billion. BP also said it was selling two gas-processing plants in Texas. Those sales had been expected for a long time.

The Tesoro deal brought BP's asset sales to $26.5 billion since the April 2010 Gulf oil spill.

BP leased the Deepwater Horizon rig that exploded while drilling a well off the Louisiana coast, killing 11 workers and triggering a largest offshore oil spill in U.S. history. More than 1 million damage claims have been filed with a court-supervised settlement program. BP expects to complete payments into a planned $20 billion trust by the end of the year.

BP said this spring that it had marked for sale its interests in Gulf fields known as Marlin, Horn Mountain, Holstein, Ram Powell and Diana Hoover. Bloomberg said the fields hold proven reserves of 120 million barrels of oil and produced 58,000 barrels per day in the first quarter. It said potential bidders could include Chevron Corp. and Exxon Mobil Corp.

CEO Robert Dudley said in July that the company's Gulf strategy would focus on four major fields: Thunder Horse, Na Kika, Atlantis and Mad Dog.

In July, BP reported a second-quarter loss of $1.4 billion on lower oil prices, falling production and write-downs of assets including shale-gas holdings in the U.S. The loss was larger than analysts expected and a reversal from profit of $5.7 billion a year earlier. ●

GOVERNMENT

BSEE clarifies response plan requirements

The Bureau of Safety and Environmental Enforcement, or BSEE, has issued a notice to lessees clarifying the agency's regulations for the preparation of regional oil spill response plans. A regional response plan spells out the oil spill contingency arrangements that an operator of offshore oil-related facilities has in place to deal with an oil spill within a specific region.

The new notice to lessees, issued on Aug. 10, clarifies the way in which BSEE applies existing response plan regulations, incorporating lessons learned from the Deepwater Horizon disaster in the Gulf of Mexico, the agency says. The intent is to provide transparency in the plan review process and improve the efficiency of the process. BSEE says that since the Deepwater Horizon spill the agency has approved nearly 80 regional response plans using the approach outlined in the notice to lessees.

"The Deepwater Horizon response made it clear that existing oil spill response plans were not up to the task of containing and cleaning up a massive offshore blowout," said BSEE Director James Watson. "We have been using our existing authority to require more robust plans for some time now, and this NTL clarifies that approach for the industry and the public. It will assist industry in preparing response plans that will provide for a rapid, effective response to a worst case scenario."

BSEE says that it reviews each response plan to ensure that the proposed spill response strategy has the resources necessary to deal with the anticipated worst case oil discharge in the region covered by the plan. Required resources include capping and containment equipment for dealing with a subsea well blowout. As appropriate, BSEE will also consider incorporating into a plan a range of response strategies such as advanced mechanical response systems and in-situ burning, the agency says.

—ALAN BAILEY

continued from page 12

FURIE LAWSUIT

Texas port aboard the foreign-flag heavy-lift vessel M/V Kang Sheng Kou, which hauled the rig to Vancouver, British Columbia. From there, U.S.-flag tugs towed the rig to Cook Inlet, arriving on Aug. 11, 2011, the lawsuit says.

The suit says the Kang Sheng Kou was used because the U.S.-flag Jones Act fleet had no ship capable of safely carrying the rig around South America, as the rig was too big to pass through the Panama Canal.

Furie transported the rig to Alaska "based on a reasonable belief that a national defense waiver would be granted under the Jones Act," and Homeland Security Secretary Janet Napolitano's "promise" in May 2011 that any penalty imposed would be substantially mitigated, the suit says.

Jaime Ruiz, a spokesman in Los Angeles for U.S. Customs and Border Protection, said his agency "does not comment on pending litigation." ●

Contact Wesley Loy at wloy@petroleumnews.com

● EXPLORATION & PRODUCTION

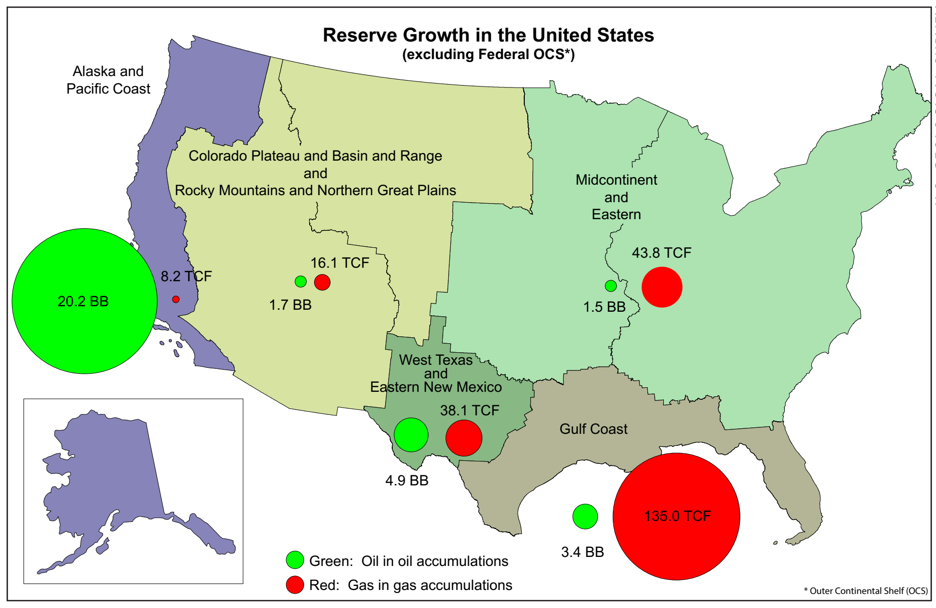
USGS estimates U.S. reserves growth

Thinks 32 billion barrels of oil reserves could potentially be added to conventional fields across the entire United States

By ALAN BAILEY
Petroleum News

The U.S. Geological Survey has published a new assessment of the extent to which the oil and gas reserves associated with known oil fields in the United States might increase in the future. The reserves additions would be achieved through a process known as "reserves growth," in which field development tends over time to reveal and enable the possibility of producing more oil than originally thought. Oil "reserves" refer to oil known to exist through exploration and development drilling, and capable of production, as distinct from oil thought to exist but unproven, or known oil that cannot be produced.

Following the new assessment, USGS thinks that there could be a total U.S. reserves growth of 32 billion barrels of oil; 291 trillion cubic feet of natural gas recovered in association with oil production; 241 trillion cubic feet of natural gas from gas fields; and 10 billion cubic feet of natural gas liquids.



U.S. GEOLOGICAL SURVEY

USGS has aggregated data for Alaska reserves growth with that from the Pacific Coast, including California. The result indicates that this composite region, with possible growth of 20.2 billion barrels, has by far the largest potential growth of any region in the U.S. The Gulf Coast has the biggest potential for natural gas reserves growth, with a potential growth of 135 trillion cubic feet. It is important, however, to stress that these growth figures relate to existing fields and bear no relationship to growth potential from new exploration and the resulting development of new fields.

It turned out that the 68 oil accumulations in the larger fields accounted for 70 percent of the total potential oil reserve growth for the United States, with smaller oil accumulations accounting for the remaining 30 percent, USGS said.

Growth trends

Traditionally, reserves growth assessments of this type are done using statistical growth trends determined from aggregated historic oilfield data. These trends enable the prediction of potential future reserves growth of known, producing oil accumulations.

In this new assessment, USGS applied this traditional technique to smaller oil fields. But, recognizing that a relatively small number of larger fields tend to make a disproportionately large contribution to the aggregate growth figures, the agency used a new technique for assessing 68 oil accumulations in 55 large oil fields. The new technique involved taking each field individually and using statistical techniques to determine likely reserve growth for that field, based on the characteristics of that particular field. The estimates for the individual large fields were then aggregated, before being aggregated with the growth estimates for the smaller fields.

Two gas fields were assessed using the new method, with all other gas fields assessed using the traditional growth trend approach.

It turned out that the 68 oil accumulations in the larger fields accounted for 70 percent of the total potential oil reserve growth for the United States, with smaller oil accumulations accounting for the remaining 30 percent, USGS said. ●

Contact Alan Bailey at abailey@petroleumnews.com

GOVERNMENT

BSEE issues finished offshore safety rule

The Bureau of Safety and Environmental Enforcement, or BSEE, has issued the final version of a drilling safety rule that establishes new standards for well casing and cementing; for third-party certification and verification of blowout preventers; for blowout preventer capabilities, testing and documentation; and for well control training. The rule, which applies to drilling on the federal outer continental shelf, originally emerged as part of emergency rule making in the aftermath of the Deepwater Horizon disaster in the Gulf of Mexico in 2010. The final version of the rule includes refinements resulting from public comments on the original rule, BSEE says.

"The oil and gas industry has been operating under these enhanced safety requirements for the past two years," said Jim Watson, director of BSEE, when announcing the issuance of the final rule on Aug. 15. "Today's action builds on the lessons learned from the Deepwater Horizon tragedy and is part of the administration's all-of-the-above energy strategy to expand safe and responsible development of America's domestic energy resources."

Refinements to the original version of the rule include features such as improved descriptions and classification of well-control barriers; defined testing requirements for cement; clarified requirements for the installation of dual mechanical barriers; and the extension of blowout preventer and well-control fluid requirements to well completions, well workovers and decommissioning operations.

—ALAN BAILEY

continued from page 1

MOVING TARGET

least environmentally damaging practicable alternative," the statement said.

The record of decision and permit "may not be complete until as late as Nov. 21," the Corps said.

'Bureaucratic foot-dragging'

The Corps issued the statement apparently in response to criticism from Alaska's governor, Sean Parnell, and its senior U.S. senator, Lisa Murkowski. The two Republican leaders issued weekend press releases decrying what Murkowski's release termed "bureaucratic foot-dragging" by the Obama administration.

A two-month delay in securing the permit could keep ExxonMobil from starting work in the upcoming winter construction season, they said. That, in turn, could jeopardize the company's commitment to commencing first production from the field by the winter of 2015-16.

"This unexplained delay threatens to set production at Point Thomson back another year, costing the state of Alaska both jobs and millions of barrels of crude oil that's urgently needed to boost throughput in the trans-Alaska oil pipeline," Murkowski said in her Aug. 11 press release.

Parnell sent a three-page letter to Interior Secretary Ken Salazar, asking him to do something about "continued federal permitting delays" on Point Thomson.

The governor noted the Point Thomson project already is a year behind due to Army Corps delays in completing an environmental impact statement.

Parnell and Murkowski said they don't want a repeat of the long permitting delays ConocoPhillips experienced on its CD-5 oil development in the National Petroleum Reserve-Alaska.

Exxon's measured response

ExxonMobil spokesman David Eglinton on Aug. 15 provided Petroleum News this statement by email:

"U.S. Army Corps of Engineers approval is critical to progressing the project work required to put Point Thomson into production during winter 2015-16. We continue to work closely with the U.S. Army Corps of Engineers to provide requested information to support its work required for a final decision to allow Point Thomson construction to proceed. We will assess any schedule impacts following the Corps of Engineers' final decision."

State officials have pushed for its development for decades, and in March signed a legal settlement with ExxonMobil and its partners laying out a development schedule.

The Point Thomson field is on state land along the Beaufort Sea coastline, adjacent to the Arctic National Wildlife Refuge.

State officials have pushed for its development for decades, and in March signed a legal settlement with ExxonMobil and its partners laying out a development schedule.

The initial project involves development of three well pads and gas-handling facilities, as well as a 22-mile pipeline. First production is expected to be 10,000 barrels per day of liquid condensate.

Point Thomson development will require billions of dollars in investment, ExxonMobil has said.

The company is working on multiple fronts to permit the site construction and pipeline, and to arrange the many contractors needed for the job. Generally, construction on the North Slope must be done in winter when the fragile tundra is frozen.

What should go where?

ExxonMobil is operator of the Point Thomson unit, with other major stakeholders including BP and ConocoPhillips.

Whether ExxonMobil will get the permit isn't the issue; it probably will.

The question is what conditions will be attached. Specifically, it appears final decisions have yet to be made on placement of certain well pads, pipelines, roads and other features.

A number of scenarios were offered in the massive final EIS the Corps released July 27.

Because the majority of the Thomson Sand reservoir is beneath the Beaufort Sea, offshore development would maximize access. But such an approach was ruled out because of the added environmental risk and the availability of long-reach drilling technology, allowing for wells drilled from onshore pads, the EIS said.

ExxonMobil prefers placing the pads right on the coastline, and the state concurs. But some federal officials favor

see **MOVING TARGET** *page 20*

Petroleum news

Oil Patch Bits

UIC announces 2nd annual charity golf tournament

UIC Technical Services, a member of the Ukpea vik Iñupiat Corp. family of companies, said Aug. 1 that it is hosting its second annual UIC Foundation Charity Golf Tournament on Sept. 18. The tournament will take place at a new location, Swan Point Yacht and Country Club in Swan Point, Md. In addition to the golf tournament, the event will include a raffle and both a silent and live auction for donated items including Alaska Native art.

Proceeds from this event will benefit the UIC Foundation, a non-profit organization that provides scholarship funding to qualified Alaska Native students. The foundation has distributed over $400,000 in scholarships over the past three years to qualified recipients attending college or vocational school. The foundation provides financial assistance with items such as tuition, fees, and books. You can learn more about the UIC Foundation at www.ukpik.com/uicfoundation.htm.

The success of this event is credited largely to its sponsors, who lend their names and financial support. By participating as a sponsor, organizations benefit from extended exposure through promotional efforts directed toward the supporters of the UIC Foundation including a thank you ad in Petroleum News, as well as the UIC newsletter which is mailed to UIC's over 2,500 Iñupiat shareholders. Those interested in sponsoring can contact event organizer Kelvin Martinez at 703-562-0340 or Kelvin.Martinez@bowheadsupport.com.

For more information on the UIC Foundation Charity Golf Tournament and to register, visit www.cvent.com/d/pcqzxv/1Q.

ECA compliance waiver granted to US ship owner TOTE

As reported on the MarineLink website Aug. 8th, Totem Ocean Trailer Express has received a permit providing a conditional waiver from the current Emissions Control Area fuel sulfur content requirements of MARPOL Annex VI regulation 14.4 while the company pursues conversion of its vessels to alternative fuels. The permit was issued by the United States Coast Guard under authority provided in Regulation 3 of Annex VI.

This permit is the product of a public-private partnership among TOTE, the United States Environmental Protection Agency and the USCG. It will enable TOTE to develop and convert its two ORCA-class vessels, already the "greenest" ships in the U.S. domestic fleet, to the use of liquefied natural gas, LNG, as their primary fuel source. The conversion will advance technology and accelerate the use of natural gas as a cleaner domestic energy source.

"This is the first permit issued under the Annex VI, Regulation 3 program, and it is tangible evidence that when committed organizations join together, innovative solutions can result," said Phil Morrell, vice president of Marine and Terminal Operations at TOTE.

Totem Ocean Trailer Express is one of six operating companies owned by TOTE Inc., a subsidiary of Saltchuk Resources of Seattle, Wash. The privately owned shipping company

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

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

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SHELL DRILLING

"Progress related to the final construction of the Arctic Challenger containment barge remains steady," Shell spokesman Curtis Smith told Petroleum News in an Aug. 15 email. "We continue to work closely with the U.S. Coast Guard to outline a schedule for final inspections and an on-water deployment that would lead to certification. There's no set timeline for the completion of this important process."

Site preparation

The vessels that have already headed north will prepare Shell's planned drilling sites in the Chukchi and Beaufort seas for the arrival of the Noble Discoverer and Kulluk drilling vessels, both of which remain at Dutch Harbor in the Aleutian Islands for now. Site preparation includes the positioning of the anchors for the rigs, Smith said.

Shell had planned to drill up to three wells in the Chukchi Sea and up to two wells in the Beaufort Sea this year. But because of the delayed start to the drilling season the company has scaled back its expectations to one well in each sea. However, the company has said that it may also drill some top holes for other wells, to achieve a head start on next year's drilling.

Before it can start drilling in the Chukchi Sea Shell also needs a compliance order from the Environmental Protection Agency, following a request for some changes to the air quality permit for the Noble Discoverer drillship. Shell has also requested changes to the air permit for the Kulluk, the floating drilling platform earmarked for use in the Beaufort Sea — the company can use the Kulluk meantime, pending an EPA ruling on the Kulluk permit changes.

This year the Chukchi Sea has experienced exceptionally heavy early summer ice and Shell has said that the ice would have prevented the start of Chukchi Sea drilling in July as originally planned, regardless of the situation with the containment barge.

Salazar comments

During an Aug. 13 press conference Secretary of the Interior Ken Salazar, who had just returned from a visit to the North Slope, said that the waters in the area of Shell's planned Chukchi Sea drilling are now clear of ice. At this point it is the need to complete work on the containment barge, and not sea ice, that is delaying the drilling, Salazar said.

"It's not the ice conditions that have held up the effort in terms of moving forward," Salazar said. "It's the necessity for Shell to be able to demonstrate that they have met the regulatory requirements we have put into place, and those regulatory requirements must be met. If they are not met there will not be a Shell exploration effort that will occur this year."

Salazar said that Interior still needs to make decisions on Shell's applications for drilling permits and that at this point Shell has not presented any alternative plan, such as the drilling of top holes.

"If they present an alternative we'll take a look at it, but right now the plan as I have understood it is that they are still moving forward to get their containment vessel certified and their plans are still to move forward with the drilling of an exploration well or two up in the Chukchi and in the Beaufort Sea," Salazar said, adding that Interior would ensure that any requested change to Shell's plans meets the appropriate regulations and that the environment of the Arctic is protected.

Little risk of spill

"The exploration that takes place, if it does take place, will take place under the most cautious, highest guarded activity ever in the history of any kind of ocean energy development," Salazar said. "So I'm not very concerned frankly that we are going to have any kind of an oil spill by these closely guarded exploration activities."

The larger questions that need to be addressed over a longer period of time, before any outer continental shelf development takes place, include issues such as the local infrastructure and Coast Guard capabilities, Salazar said.

And, with environmental conditions in the Arctic in a state of flux under the effects of climate change, science will be critical to future decision making, he said.

Meantime, the current situation with Shell is dynamic.

"We don't know yet what will be happening this summer, what will be happening in the next 10 or 20 days," Salazar said. "We don't have an alternative from them. … I will hold their feet to the fire in terms of making sure that we are doing everything we can do abide by the standards and regulations we have set and to make sure that the environment in the Arctic seas is protected."

—ALAN BAILEY

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OIL PATCH BITS

has operated roll-on/roll-off cargo vessels between the ports of Tacoma, Wash., and Anchorage, Alaska, since 1975.

The comprehensive project will also lead to the establishment of long-term supplies of LNG for use by other sectors of the transportation industry in the Puget Sound region.

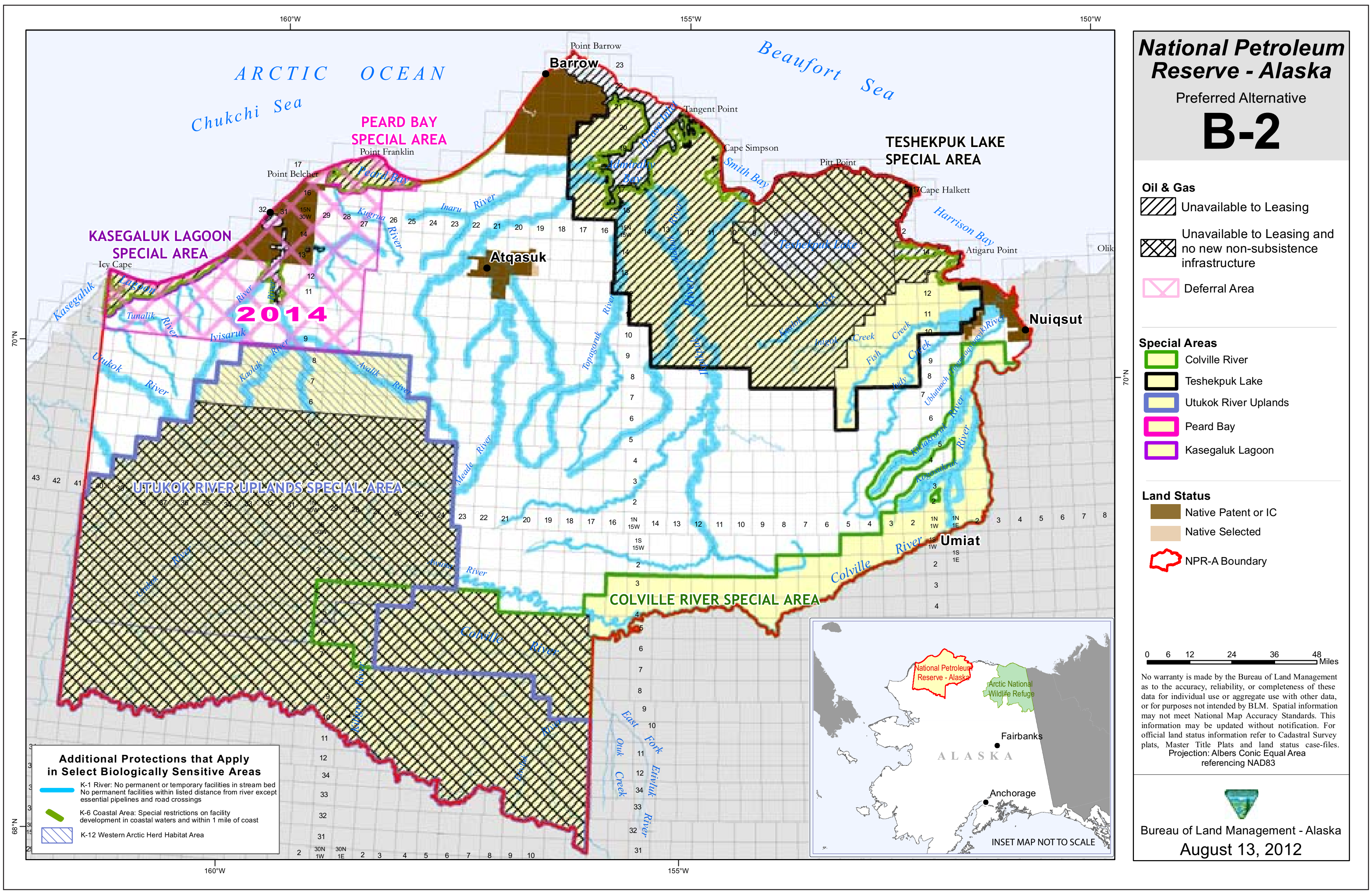
Crowley's logistics group named a top provider

Crowley Maritime Corp. said Aug. 6 that its logistics group has been selected as a Top 100 third-party logistics provider by a major logistics industry trade publication, Inbound Logistics, for the fourth consecutive year. The list serves as a qualitative assessment of service providers deemed as the best equipped to meet or surpass readers' evolving outsourcing needs.

Editors selected this year's class of Top 100 3PLs from hundreds of candidates. The service providers selected are companies that, in the opinion of the editors, offer the diverse operational capabilities and experience to meet readers' unique supply chain and logistics needs, as well as enabling them scalability.

"We are happy to recognize Crowley as a Top 100 3PL for the fourth year in a row," said Felecia Stratton, editor, Inbound Logistics. "Their consistent commitment to enhancing the customer's supply chain options while providing a complete menu of scalable services has once again been recognized by our transportation buyers and readers. In an economy where we see many companies reigning in the services they provide, Crowley's continued expansion throughout their service areas makes for a reliable long-term partnership to logistics customers."

Editor's note: All of these news items — some in expanded form — will appear in the next Arctic Oil & Gas Directory, a full color magazine that serves as a marketing tool for Petroleum News' contracted advertisers. The next edition will be released in March.



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NPR-A PLAN

for oil and gas leasing. This land is estimated to hold about 549 million barrels of discovered and undiscovered economically recoverable oil and approximately 8.7 trillion cubic feet of economically recoverable natural gas, which constitute "the vast majority of projected oil resources in the NPR-A available for leasing," Interior said in a release accompanying Salazar's announcement.

The preferred alternative also allows for the possibility of future pipelines and other infrastructure to support offshore oil and gas production in the Beaufort and Chukchi seas, Interior said.

"The proposal would allow us to expand our leasing in the NPR-A, as we have done over the last three years, and to build on our efforts to help companies develop the infrastructure … to bring supplies of petroleum products online," Salazar said in announcing the preferred alternative. "This plan also strikes an important balance by recognizing the need to protect America's treasures in the Arctic, from the raptors of the Colville River and the polar bears of the Beaufort Sea coast, to Teshekpuk Lake, Peard Bay, and some of the largest caribou herds on Earth."

The proposed plan will make about half of the total area of the NPR-A available for leasing and will provide a roadmap for the transition from leasing through cautious exploration to "smart development," Salazar said.

Off limits area

Under the plan a large area of land in northern NPR-A, around Teshekpuk Lake, Smith Bay and Admiralty Bay would be off limits to oil and gas leasing. Many in the oil industry view this land, especially land immediately south of the Beaufort Sea coast, as particularly prospective because of the proximity to a major geologic structure called the Barrow Arch, a structure closely associated with major North Slope oil fields.

Sen. Lisa Murkowski, R-Alaska, responded to the Interior announcement with a terse statement.

"Today, the Obama administration picked the most restrictive management plan possible," Murkowski said. "The environmentally sensitive Teshekpuk Lake area was already under a 10-year deferral for additional study, but this alternative goes vastly beyond that, putting half of the petroleum reserve off limits. This decision denies U.S. taxpayers both revenue and jobs at a time when our nation faces record debt and chronic unemployment."

Environmental organizations took a predictably different view.

"We are encouraged that the Bureau of Land Management is taking steps to balance oil and gas development with the need to protect important wildlife habitat in the western Arctic's National Petroleum Reserve-Alaska," said Dr. Wendy Loya, lead ecologist for the Alaska regional office of the Wilderness Society and a member of the North Slope Science Initiative's technical advisory panel. "If adopted, the preferred management strategy in the National Petroleum Reserve-Alaska would protect the calving grounds of the Teshekpuk Lake and western Arctic caribou herds. Essential nesting habitat for thousands of shorebirds, molting habitat for geese, and coastlines used by for walrus haul-outs and polar bear dens would not be developed under this plan. This is the right management choice to give scientists more time to better understand the changing Arctic and to protect habitats used for subsistence.

Pipeline routes?

Sen. Mark Begich, D-Alaska, expressed concern that areas designated for special environmental protection might block the construction of a pipeline across the reserve, thus placing at risk the potential development of oil from the Chukchi Sea.

"If the DOI is leaving Kasegaluk Lagoon near Wainwright a special protected area, where many people assume a pipeline will come ashore, what additional conditions are going to have to be met and how feasible is it to get a pipeline in there? The same is true if the pipeline has to cross over a new protected area to the west of Alpine," Begich said. "We've known since the beginning that a pipeline across the NPR-A is a critical piece of the puzzle for successful Arctic development."

On Aug. 13 Salazar told reporters that it would be possible for a future pipeline to cross a special area provided that the pipeline met the conditions required to protect the environmental values that the spe-

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NPR-A PLAN

cial area was designed to address.

"What the plan does … is it still allows a pathway forward for the construction of a pipeline that would take place somewhere across the NPR-A," Salazar said. "But those decisions would be made in the future. They would be decisions that would be subject to a thorough environmental impact analysis before any decisions are made on any kind of permit that we granted."

Multiple goals

Salazar said that since 2009 the Department of the Interior's Arctic planning decisions have been guided by environmental conservation values; the need to ensure that the subsistence needs of Native Alaskans are honored; and the need to enable oil and gas development.

Regardless of the importance of oil and gas development in NPR-A and the importance of the nation's energy needs, it is equally important to realize that NPR-A includes an iconic landscape comparable in significance to other great landscapes of the United States, Salazar said. And the reserve includes important habitat areas for a variety of wildlife, he said.

"When we talk about the two caribou herds in the National Petroleum Reserve, they're the largest caribou herds that we have in this nation," Salazar said. "When you think of one caribou herd at over 350,000 in population and the important subsistence uses that provides, it is an iconic place of our Earth."

Subsistence values

Recounting a visit with Edward Itta, previous mayor of the North Slope Borough, including a trip to a subsistence camp and to an ice cellar used to store the products of subsistence hunting, Salazar emphasized the importance of the subsistence values of the Native communities.

"We know that 40 northern and western Alaska Native villages are dependent on the food that comes from the caribou and from the waterfowl and other wildlife that they hunt," Salazar said.

Going down the path of those who would close the entire NPR-A to all development would mistakenly ignore the importance of U.S. energy security, while opening the entire reserve to development could mar the landscape, leading to the need for hugely expensive restoration, Salazar said.

"We want to make sure that we don't mess it up," Salazar said. "It has to be done right so that the conservation values which are so unique to these 22 million acres are in fact honored and are in fact protected."

Over the next few weeks officials from the Bureau of Land Management will consult with other government agencies — the State of Alaska, the North Slope Borough, the U.S. Fish and Wildlife Service and the Bureau of Ocean Energy Management — that are participating in the development of the environmental impact statement, or EIS, for the plan, Mike Pool, acting director of the Bureau of Land Management, told the Aug. 13 press conference. A final EIS will follow. There will then be a 30-day public comment period before BLM completes its plan and EIS decision, ready for signing off by Salazar.

"We project that decision to occur sometime in December," Pool said. ●

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LINC ENERGY

Highway.

So Linc delayed its program by one year.

While the 2012 edition is similar the 2011 edition, Linc expects the program to be enhanced by a year of additional technical work, 3-D seismic processing and interpretation, project development and community engagement. In addition to three community meetings in Anaktuvuk Pass and Nuiqsut over the winter and early spring, Linc launched a project specific website, www.lincenergyumiat.com, in April 2012.

This winter, Linc plans to drill as many as three vertical wells — two shallow and one deep — a horizontal well into the Lower Grandstand formation and a disposal well.

The Umiat prospect is one of the white whales of northern Alaska.

The U.S. Navy discovered the field in 1946, during its epic drilling campaign across the National Petroleum Reserve-Alaska. But the field has remained undeveloped because of its remoteness from infrastructure, historically low oil prices and insufficient technology at the time to unlock the shallow oil in a reservoir partially located within permafrost.

With high oil prices and the state considering plans to build an all-season road to Umiat, interest in the prospect increased over the past decade. The small independent Renaissance Umiat LLC announced an exploration program in 2007, but ultimately delayed drilled on numerous occasions before selling the prospect to Linc in mid-2011.

Now, Linc says it is "committed" to developing Umiat, and is studying facilities, pipeline and access scenarios "to determine the best, most efficient, plan for development." And while a road to Umiat "would have a very positive impact on the Umiat development program," Linc believes "Umiat could be successfully developed without a road."

UCG online in five years

Although it hasn't received as much public attention as its Umiat project, Linc has also been pursuing an underground coal gasification exploration program over the past year.

In late 2011, Linc spud the first hole in its Alaska underground coal gasification program, TYEX01/01X, on the west side of Cook Inlet, less than three miles from the Beluga Power Station. Linc called the results of the 1,450-foot core hole "very encouraging."

Linc also acquired 2-D seismic over its Interior and Cook Inlet underground coal gasification acreage between September 2011 and April 2012. The company also called those results "very encouraging," pointing in particular to its acreage in the Interior "where there is very little previous exploration drilling and very few well logs exist."

Linc plans to drill two more exploration holes on the west side of Cook Inlet this summer and fall followed by one exploration hole in the Interior region, near Healy.

The goal of the program is to target specific sites for future commercialization.

For the upcoming exploration program, Linc commissioned a new, fit-for-purpose rotary-core rig from Buffalo Custom Manufacturing. The dual capabilities allow the rig to "drill at a faster rate and offer greater borehole stability and control than a traditional core rig."

Linc is aiming to bring synthesis gas production online in Alaska within five years.

Underground coal gasification is a way to "create" natural gas inside coal deposits too deep to mine. The process involves injecting air and water into an ignited coal seam to synthesize the carbon and hydrogen into methane, the main ingredient of natural gas.

Linc announced its underground coal gasification plans as soon as it arrived in Alaska in early 2010, but those plans grew when the Alaska Mental Health Trust awarded the company an underground coal gasification exploration license over three large blocks.

Linc said it currently holds 167,917 acres of exploration licenses.

Waiting on unit decision

And Linc continues to pursue conventional gas targets in Cook Inlet, as well.

While much of the acreage it picked up in March 2010 recently expired after the end of its primary term, the company continues to hold one state and one Alaska Mental Health Trust lease in the Point MacKenzie region north of Anchorage. Linc recently applied to form the Angel unit around those leases and expects to have a decision in August.

The proposed unit is located just southwest of where Linc drilled the LEA No. 1 well in late 2010. Although Linc decided LEA No. 1 couldn't produce in commercial quantities, "incorporating the data gathered during the LEA No. 1 program into our exploration model resulted in an exciting play development within the proposed Angel Unit." ●

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ARCTIC ROUTE

In an interview with the Canadian Broadcasting Corp., McLeod said that although his preference is still to revive stalled plans for shipping natural gas from the Mackenzie Delta to southern Canadian and U.S. markets, "we are prepared to look at other options, including the Northern Gateway."

Earlier in August, McLeod said that if British Columbia Premier Christy Clark's stand against Northern Gateway reduces Canada's energy export hopes and establishes a "new order of doing business," by requiring a wider sharing of revenue among provinces it is important to "keep all of our options open."

Alberta willing to talk

Alberta Intergovernmental Affairs Minister Cal Dallas was quick to welcome the suggested alternative.

He said his government would be "more than pleased to talk to (McLeod) and anyone in the NWT who is interested in cooperating on projects.

"We view McLeod's comments as a signal that the NWT recognizes that access to markets for Alberta energy would really enhance economic opportunities and jobs across Canada.

"A northern route that would see our bitumen transported out of the NWT to Asia might be a project that could be actively contemplated at some point in the future," he said.

Backlash predicted

But the prospect of an oil sands pipeline through the NWT would likely face the same wall of resistance as pipelines elsewhere in Canada.

Fred Carmichael, chairman of the Aboriginal Pipeline Group, which has the option of a one-third equity stake in the Mackenzie Gas Project, said a pipeline to the Beaufort Sea would face a backlash from environmental and aboriginal organizations.

He suggested the battle against a northern oil route would match that currently being waged against Northern Gateway.

Jack Mintz, director of the School of Public Policy at the University of Calgary, said that if Northern Gateway and Trans Mountain get blocked "it's hard to see what other options there would be in terms of market diversification, like getting oil to Asia."

He said carrying crude through the NWT is not likely to be a viable alternative, given the difficulties of establishing northern shipping lanes.

Mintz also argued that plans to expand and extend pipelines to Central Canada and the Atlantic region do not amount to true market diversification because most of the crude would likely end up in the U.S.

CAPP focused on B.C.

David Collyer, president of the Canadian Association of Petroleum Producers, told the Calgary Herald that his organization is concentrating mostly on establishing shipments to the British Columbia coast.

However, he said rail shipments to the U.S. Gulf Coast, the West Coast and possibly pipelines to Central and Eastern Canada are all part of the mix that is being explored.

Collyer argued that pipelines to tanker ports on the West Coast remain the safest and most economical way to transport large volumes of crude, which means rail offers only a limited role.

On the NWT option, he said producers "have to be realistic," given that Northern Gateway and Trans Mountain have already involved years of work on design, community consultation and efforts to obtain commercial support.

Prospect of ice-free Beaufort

Lending some weight to the notion of year-round tanker movement in the Beaufort Sea, the European Space Agency said Arctic sea ice could disappear entirely by 2022.

Issuing results from two years of satellite studies, it estimated that 900 cubic kilometers of ice have disappeared every year since 2004, leaving only 7,000 cubic kilometers — a dramatic rate that has scientists estimating there could be no sea ice coverage within a decade.

They said the thinning of ice is advancing 50 percent faster than most has predicted, noting the absence of ice caps could see the release of more greenhouse gas methane into the atmosphere, further accelerating global warming and rising sea levels.

However, Seymour Laxon, with London's Center for Polar Observation and Modelling, told the Guardian newspaper that the latest figures are still based on preliminary studies and that the current rate of ice loss might slow down.

NWT facilities a challenge

Doug Matthews, a northern energy consultant and former NWT manager for oil and gas development, told the Globe and Mail newspaper that the challenge of building a pipeline, port facilities, icebreakers and coast guard capacity in the NWT would pose a "huge burden" and would need to be backed by a critical mass of oil or gas for export.

He said McLeod is "just expressing the frustration" of the NWT after years of trying to negotiate the development of its own energy resources.

"You can't just say you're an energy superpower. You have to act like one," he said. "The guys down south can't seem to get their act together."

Aside from its own vast natural gas resources, the NWT is pinning hopes on prospects for the Canol shale oil find in the Central Mackenzie Valley, where companies — including Royal Ditch Shell, Husky Energy, Imperial Oil and ConocoPhillips — have committed C$627 million in the two latest bidding rounds for 13 parcels.

NWT Industry Minister David Ramsay estimates the "massive piece of real estate" could hold 2 billion to 3 billion barrels of recoverable oil, putting it in a similar league with the Bakken.

Husky has plans for this winter to evaluate two vertical wells drilled last year and, although there is concern over the use of hydraulic fracturing in Canol, the NWT government plans to meet in Calgary Aug. 20 with industry, regulators and environmental groups to learn more about the technology and it impact on water in a fragile region.

Environmental lawyer Stephen Hazell said shale oil development in the North should be rigorously studied before it proceeds to the commercial stage.

If the early indications of major discoveries are firmed up they could further reinforce the prospects of feeding oil into a pipeline destined for the Beaufort Sea and Asia.

—GARY PARK

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MOVING TARGET

pushing some of the pads and other infrastructure inland.

While the Army Corps is the lead permitting agency for Point Thomson, two other federal agencies have been providing input — the Fish and Wildlife Service and the Environmental Protection Agency.

"In evaluating the proposed project under the Clean Water Act, we are committed to making a decision that balances protecting aquatic resources with reasonable development," the Corps said in its Aug. 14 statement.

ExxonMobil has provided "some conceptual alternate location maps and figures" that weren't in its permit application, the Corps said. The plans "depict a geographic shift" of the project's east and west pads away from the coast "in an attempt to meet agency environmental concerns."

In his letter to Salazar, Parnell wrote: "The Corps has received agency input on the Point Thomson project for almost three years. Any major amendments to the proposed project should not happen during the last stages of the permitting process."

He asked the secretary to "exercise your authority to improve and coordinate permitting" of Alaska energy projects.

The Corps cautioned it was addressing many issues on the large Point Thomson proposal, and "target dates may move" on making a permit decision. ●

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