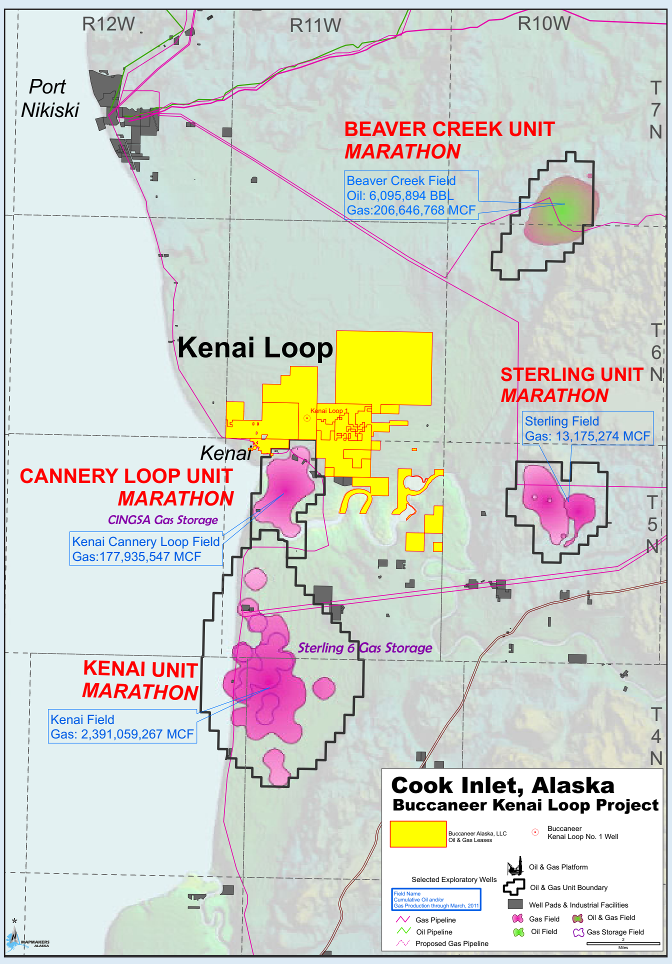
Petroleum news

Vol. 16, No. 30 • www.PetroleumNews.com

A weekly oil & gas newspaper based in Anchorage, Alaska

Week of July 24, 2011 • $2

page 3 Persily: state shouldn't wait on others, should start gas fiscal negotiations



Buccaneer releases Kenai Loop gas estimates; plans second well

The Kenai Loop prospect contains 31.5 billion cubic feet of natural gas and 3.9 million barrels of oil equivalent in proven reserves, according to operator Buccaneer Energy Ltd.

The figures come from an independent reserve analysis conducted by the consulting firm Ralph E. Davis Associates Inc., the Australian independent said in a statement on July 20.

The analysis on the onshore field on the Kenai Peninsula put the "proven and probable," or 2P, reserves at 38.3 bcf and

see **KENAI LOOP** *page 23*

Escopeta's Spartan 151 jack-up rig again on way to Cook Inlet

The Spartan 151 is once again Alaska-bound.

The jack-up drilling rig left the Vancouver area on July 20, according to Escopeta Oil Co., the Houston independent that plans to use the rig for an offshore drilling program.

The rig is headed directly for the Kitchen Lights unit in upper Cook Inlet, where Escopeta plans to begin its exploration program by drilling at the Corsair prospect.

The rig is expected to arrive sometime in the first week of August.

Foss Maritime Co. is towing the rig using three tugs — one 6,000 horsepower tug and two 4,500 house power tugs. Foss Maritime is using U.S. flagged ships for the trip.

The Spartan 151 left the Gulf of Mexico in March, sailing around the tip of South America on the M.V. Kang Sheng Kou heavy lift vessel, but got held up off the coast of British Columbia because of issues related to the federal Jones Act. That law requires ships moving between domestic ports to be built, flagged and manned domestically.

The news brings Escopeta another step closer to drilling its first well in Alaska, a milestone it has been working toward to varying degrees since arriving in 1994.

Escopeta must begin drilling by Oct. 31 to meet state work commitments.

—ERIC LIDJI AND KAY CASHMAN

FINANCE & ECONOMY

New inlet player

Houston-based, privately held Hilcorp buying Chevron's Cook Inlet assets

By KRISTEN NELSON

Petroleum News

The familiar logos long associated with Union Oil Company of California and Chevron will soon be absent from Alaska's Cook Inlet, replaced by a new logo, that of Houston-based Hilcorp Energy Co.

Chevron and Hilcorp said July 19 that Hilcorp is acquiring Union Oil's Cook Inlet assets.

Financial terms were not disclosed. The transaction is expected to close by year end pending customary regulatory approvals.

Assets in the sale include Union Oil contracts and interests in the Granite Point, Middle Ground Shoals, Trading Bay and MacArthur River fields; interests in 10 offshore platforms; interests in onshore gas fields including the Ninilchik unit and the Beluga River unit; and two gas storage facilities.

Current net production from the assets is some 3,900 barrels of oil and 85 million cubic feet of natural gas per day.

In a CEO message on Hilcorp's website, Jeff Hildebrand, the company's founder, president and CEO, cited "world-class employees, legacy assets and a strong balance sheet," as the reasons for the company's success.

see **NEW PLAYER** *page 22*

LAND & LEASING

A 'best interest' fight

DNR: Ruling could cause oil and gas delays, appeals to Alaska Supreme Court

By WESLEY LOY

For Petroleum News

The Alaska Department of Natural Resources is asking the state Supreme Court to overturn a lower court ruling the agency says has potential to delay oil and gas exploration.

The case concerns the extent to which DNR is obliged to prepare written findings on whether the leasing of state-owned land is in the state's best interest.

In February, a state Superior Court judge held that DNR's practice of issuing only one best interest finding prior to a lease sale or sales is insufficient. Rather, he ruled the agency has an "ongoing duty" under the Alaska Constitution to issue such findings for subsequent project phases.

The ruling was a victory for a group of Alaska Native and environmental plaintiffs who challenged DNR's Nov. 9, 2009, finding in support of planned 2009-2018 lease sales involving some 2 million Beaufort Sea coastal acres stretching from Barrow to the Canadian border.

The group argued DNR is required to do best interest analyses not only at the leasing stage, but

The DNR petitioned the Supreme Court to review and reverse the judge's ruling, and the high court has accepted the case.

see **COURT RULING** *page 23*

NATURAL GAS

Shell pulling out of Mac

Sets Aug. 31 deadline for bids on Niglintgak discovery, APG confident in interest

By GARY PARK

For Petroleum News

Whether it will be business as usual under changed ownership, or a damaging blow to an already uncertain operation might be known by the end of August — the deadline Shell Canada has set for accepting bids to acquire its 11.4 percent stake in the Mackenzie Gas Project.

To little surprise from those conversant with the project, Royal Dutch Shell has decided to shift the focus of its Canadian unit away from its Mackenzie Delta gas holdings to other assets, notably the Alberta oil sands and British Columbia shale gas prospects, which could be tied to an LNG export venture.

The primary northern asset is Shell's 1971 Niglintgak discovery, which contains an estimated 1 trillion cubic feet of recoverable gas. It is one of three fields that underpin the MGP.

The other corporate gas owners are lead partner Imperial Oil, with a 34.4 percent stake from its 100

None of the remaining MGP partners has shown any interest in bidding for the Shell Canada assets, although APG chairman Fred Carmichael told reporters said his group is "not really concerned" about the outcome of the sales process.

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● NATURAL GAS

Persily: State needs to begin negotiating

Federal coordinator says there is room in market for North Slope gas; state needs to stop waiting, start fiscal term discussions

By STEVE QUINN
For Petroleum News

Larry Persily has seen the prospects of a large-diameter natural gas pipeline from the perspective of a journalist, a deputy revenue commissioner, a Washington, D.C.-based aide in Sarah Palin's administration and a legislative aide.

Now he serves as the federal coordinator for Alaska natural gas transportation projects under the Obama administration.

It's a daunting job that places him squarely in the middle of discussions ranging from regulatory debates and questions over whether the state will ever get a natural gas pipeline under construction.

Since taking the job in March 2010, the state went from competing large-diameter projects to a single pursuit by TransCanada and Exxon, while the prospect of an in-state line has emerged.

Just after returning from the National Association of Regulatory Utility Commissioners in Los Angeles, Persily spoke to Petroleum News about his first 15 months at the helm and his thoughts on the natural gas market and how it could affect the prospects of a long-awaited, large-diameter gas line for Alaska.

Q AND A

Petroleum News: What did you take away from the conference in Los Angeles?

Persily: That the state utility and regulatory commissioners are seeing the benefit of certainty of supply along with the certainty of price, that they are starting to look favorably at power generation to go out and sign long-term deals for gas supply and hedge for the future. Even if it means in some years they might pay less for gas supplies in the spot market, it's OK because they are guaranteed that supply. It's important for the Alaska project because the producers are going to have to sign to move 4.5 billion cubic feet a day everyday for 20 years to finance the project; they are going to want to sell the gas to someone for the next 20 years. As utility regulators feel comfortable with an abundant, stable, long-term domestic supply, they are looking at longer-term deals and that helps underpin financing.

Petroleum News: What have you learned about natural gas markets since taking this job?

Persily: Everyone who makes a prediction is wrong, myself included. Aside from that it's very complex. A lot of factors go into it. Clearly demand is on the upswing as is supply. Those two seem to be irrefutable facts. Utilities and power generators continue to be nervous over what kind of air quality regulations are on the horizon and how it will affect coal as a fuel for electrical generation. How much that is going to effect the future of gas, the gas demand and gas prices — well, those are some pretty big unknowns.

Petroleum News: Is that why so many predictions can be wrong?

Persily: Anything can affect it: weather; the environmental opposition to hydraulic fracturing; the regulations on coal plants; discoveries; the economy; hurricanes. All factor into it. There does seem to be a consensus that we are in for a long time of stable prices. The abundance of shale gas will prevent the price spikes we had in 2000-2001 and 2008. Before shale gas production took off utilities were worried about price spikes. Are you going to spend a billion dollars on a huge gas fired plant when you don't know the cost of fuel for 30 years and if they are going to be able to pass that on to consumers? The spikes we had in past decade scared the hell out of them, and consumers and politicians.

JUDY PATRICK

Federal Coordinator Larry Persily

Petroleum News: Does North Slope gas have a future outside of Alaska?

Persily: Yes, it does. I think Alaskans need to realize they have an interest in a commodity, which is not as scarce as they thought it might be a few years ago, but it's still in high demand. North America burns a lot of natural gas. Between the U.S. and Canada something like 80 billion cubic feet a day. Yes, shale gas is growing but conventional gas production is declining much like North Slope oil. So you need a lot of new gas to replace the old stuff that isn't there anymore and a lot of new gas to supply the new demand. If Alaskans get realistic as to what their gas is worth, at least in the short term, and look at the benefits over 50 years of a big gas line project with cheapest gas for Alaskans and with concurrent oil and gas exploration that would occur in the North Slope, we could still do very well with a North Slope gas line. The leaders of the state have to sit down and see if they can negotiate reasonable fiscal terms with the producers. The producers are going to have to take risks of billions and billions of dollars to pay for construction and the mortgage for 20 or 30 years until it's paid off.

Petroleum News: I don't see any movement of that kind. When should it begin?

Persily: I'd say they do it now. It's going to take two or three years realistically to negotiate fiscal terms. Why not start in 2011. The Trans Canada-Exxon schedule calls for them to receive a yes or no on their certificate application from FERC in 2014. If it's going to take two or three years to negotiate fiscal terms, why not start now?

Petroleum News: Should we be concerned by the lack of news from the open season? We are about 13 months past the end of it.

Persily: We should be realistic. Commercial negotiations are high-centered because Point Thomson hasn't been resolved, because there has been no initiation of initial talks with the state, because the three producers aren't exactly best buddies to begin with, because gas prices are low. BP has other things it's dealing with — its problems in Russia. Conoco is busy splitting itself into two companies and getting a new CEO. There are other things the companies have to do so rather than wait for their schedule, why don't we force the issue? Why don't we find out is it possible to negotiate fiscal terms? I haven't seen or heard anything that tells me it's impossible.

Petroleum News: Should we presume that it's uneconomical?

Persily: Anybody who proclaims it's uneconomical is looking at today's spot prices, which have nothing to do with a decades-long, multibillion-dollar investment. Yes it's uneconomical at today's prices. No one is building it today and locking in today's prices for the next 50 years.

Petroleum News: Didn't you say last year if they didn't have precedent agreements by now it was bad?

Persily: In December when Trans Canada didn't meet its self-imposed deadline, well, yeah I worried because I think Alaskans are giving up on the project without trying. AGIA was oversold to Alaskans and to the Legislature. It doesn't get you a project. All it gets you is a certificate, which is valuable if you're going to build a pipeline. But if you're not going to build a pipeline that's a $500 million certificate to hang on the wall. It's part of the job, but wasn't going to get you a project. Anyone who believes so, who says so, it's misleading. So the state had decided four years ago in the interest of moving this along, to get a certificate. Now Alaskans

see **PERSILY Q&A** page 19

NATURAL GAS

AGDC sees 2018 as crucial year for gas

Recommends public ownership of gas line from North Slope to Fairbanks, Southcentral, with construction, operation contracted out

By KRISTEN NELSON
Petroleum News

Alaskans could end up burning their permanent fund checks to keep warm — or they could take action to get North Slope natural gas to Fairbanks and Southcentral by 2018.

That was the way Dan Fauske, CEO and executive director of the Alaska Housing Finance Corp. and president of AHFC subsidiary Alaska Gasline Development Corp., put the options to the Anchorage Chamber of Commerce July 18.

He said he worked on AGIA, the Alaska Gasline Inducement Act, and really hopes it works, because in addition to gas that project would bring the state $2 billion in revenue.

But two concerns prompted the Legislature to ask for an evaluation of an in-state gas pipeline, Fauske said: the fear that AGIA might fail to produce a large line from the North Slope to market, and the fear that Southcentral Alaska was running out of natural gas.


DAN FAUSKE

Alaska's two largest cities are currently at risk, he said: Fairbanks pays too much for energy and Anchorage could run out of natural gas, which has been used for electricity and home heating in the area for decades.

Fauske said that in his AHFC role he's concerned that some $2.2 billion in mortgages the agency holds in the state's central population corridor will be worthless without energy to heat those homes.

The establishing legislation, House Bill 369, requires that the Alaska Stand Alone Gas Pipeline or ASAP be economically feasible; deliver gas at the lowest cost to residents; allow connections for industrial use, utilities and residents; and use state land, existing highway and railroad rights of way to the maximum extent possible.

Fauske, with Dave Haugen, the AGDC project manager, and Michael Rocereta, AGDC's commercial manager, briefed the chamber on the status of ASAP and why the project is important.

State ROW secured

Haugen said proper project pacing is important and said that aspect of ASAP was reviewed by Independent Project Analysis, which assesses where a project is "in terms of a staged-gate approach."

With megaprojects, those over a billion dollars in size, you work through phases with a go/no-go decision gate at the end of each phase, narrowing project uncertainty as you move through the phases.

Phase 1, business development, has been completed, Haugen said, and the project is moving into the phase which culminates in an open season.

In that open season, the market will determine whether the project is valid.

The state right-of-way lease has been finalized and signed by Fauske, "so we have over 400 miles of the pipeline alignment now in title to AGDC and that was accomplished just like it was supposed to be in HB369," Haugen said.

The environmental impact statement and record of decision are expected in early 2012, followed by issuance of the federal right-of-way grant. The EIS will be out for public review later this summer, Haugen said.

While some private and Native corporation right-of-way agreements will be required, "early in the 2012 timeframe we should have a completed EIS as well as control of most of the right of way, all the way from Prudhoe Bay" to Southcentral, he said.

Some 2,000 other permits are required, some of which require long lead time, and that work is under way, Haugen said.

Supply issues

Rocereta, the project's commercial manager, said AGDC worked with a team led by Kurt Gibson from the Alaska Department of Natural Resources on a Cook Inlet gas production forecast.

In 1995, he said, Cook Inlet produced about 600 million cubic feet a day — consistent production and cheap gas. But in about 2005, production started to decline at a 6-8 percent rate per year, and there wasn't enough gas to keep the Agrium fertilizer plant going. That decline continued at about the same rate and "toward 2010 we saw one of the trains at the Nikiski LNG plant shut down." Early this year, the plant owners, ConocoPhillips and Marathon, said they would mothball the plant.

What does the future hold?

Rocereta said if industry did in-fill drilling, deeper and shallower pool exploitation, with investment projects DNR knows about right now, production could be extended flat to 2018 at about 250 million cubic feet a day. If there were significant new discoveries brought online that could push the line out farther, he said, maintaining that 250 million which represents local demand.

But, he said, in-field drilling to maintain production takes perfect investment, and a lot of people in industry say that probably won't occur. At 10 wells per year, production could hold steady out to 2018; at five wells a year, out to 2016.

Demand issues

With a line sized at 500 million standard cubic feet a day, an industrial anchor will be needed, Rocereta said, and accounts for some 270 million cubic feet of the proposed demand. That anchor could be the existing liquefied natural gas plant in Nikiski; it could be a greenfield plant; or "other industrial users that we haven't imagined."

There are several mining projects which could use natural gas, and AGDC included one, at 30 million cubic feet a day. There is also an enriched stream of natural gas liquids in the fuel gas volume, which totals some 60 million cubic feet a day.

There will be some ethane, propane and butane shipped along with the methane, and the idea here is whether additional propane and butane can be mixed into the stream and perhaps exported, he said, so some 30 million cubic feet a day of NGLs were included with fuel gas, a total volume of about 60 million.

"Does the project live or die by shipping that enriched stream," Rocereta asked. "The answer is absolutely not."

Without that stream the net tariff impact is about a dollar, but "we have other commercial levers that we can pull in other places that could make up for that," he said.

Fairbanks demand of about 60 million cubic feet was included, along with about 100 million for Anchorage residential, commercial and Railbelt power, to make up the 500 million cubic feet of forecast demand for ASAP.

Anchorage demand continues to grow as Cook Inlet supply declines, so over time ASAP would meet some, but not all, of the demand from Cook Inlet.

The Susitna dam project, projected to come online in 2026, would be equivalent to some 50-60 million cubic feet of gas a day, Rocereta said, so the dam isn't in competition with ASAP.

Shipper, buyer interest

ASAP held an expression of interest meeting, a non-binding open season, which brought together the North Slope

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Petroleum News and its supplement, Petroleum Directory, are owned by Petroleum Newspapers of Alaska LLC. The newspaper is published weekly. Several of the individuals listed above work for independent companies that contract services to Petroleum Newspapers of Alaska LLC or are freelance writers.

OWNER: Petroleum Newspapers of Alaska LLC (PNA)
Petroleum News (ISSN 1544-3612) • Vol. 16, No. 30 • Week of July 24, 2011
Published weekly. Address: 5441 Old Seward, #3, Anchorage, AK 99518
(Please mail ALL correspondence to:
P.O. Box 231647 Anchorage, AK 99523-1647)
Subscription prices in U.S. — $98.00 1 year, $176.00 2 years, $249.00 3 years
Canada — $185.95 1 year, $334.95 2 years, $473.95 3 years
Overseas (sent air mail) — $220.00 1 year, $396.00 2 years, $561.00 3 years
"Periodicals postage paid at Anchorage, AK 99502-9986."
POSTMASTER: Send address changes to Petroleum News, P.O. Box 231647 Anchorage, AK 99523-1647.

● NATURAL GAS

TransCanada eyes LNG role

Canadian pipeline says it will compete for opportunities; needs alternatives while battling for Keystone XL, new gas production

By GARY PARK
For Petroleum News

TransCanada is too big to be counted out of the running to carry natural gas to LNG export points in the United States and Canada, says the pipeline company's Chief Executive Officer Russ Girling.

To that end, the operator of North America's largest gas line is holding discussions with "various market participants … to make sure they know what we can do for them," he told an unconventional energy conference in Calgary.

"We are looking at those kinds of opportunities and we are not going to shy away from developing them," Girling said. "We will compete as hard as anybody for those opportunities if the marketplace wants them to occur."

He said that if Asian markets want access to North American gas he has no doubt the facilities will get built.

For now, Girling said TransCanada is looking for clear signals that long-term contracts to underpin LNG projects are likely to follow from recent large investment deals by Asian interests in U.S. and Canadian gas development, notably deals between Encana and Korea Gas, Progress Energy Resources and Malaysia's Petronas, Penn West Petroleum and China Investment Corp. and China National Offshore Oil Corp. and Chesapeake Energy.

He said the Asian investors likely want access to technology they can use to develop their own shale gas resources along with the option to move North American gas to their home markets, especially in the wake of the Fukushima nuclear power plant disaster in Japan.

Winners not sure

Although it is too early to predict how events will unfold, Girling said his experience suggests that "the ones you think are going to win aren't necessarily the ones that win at the end of the day."

"There's a lot of conversation that goes on and a lot of projects that are being discussed. We are in the deal flow and we will figure out where we can add value," he said.

More than just the need to ensure it has a stake in any major ventures, TransCanada needs insurance should its Keystone XL oil sands pipeline to the U.S. Gulf Coast come apart and to offset the

> *For now, Girling said TransCanada is looking for clear signals that long-term contracts to underpin LNG projects are likely to follow from recent large investment deals by Asian interests in U.S. and Canadian gas development …*

challenges to its Mainline system, which the Globe and Mail portrayed in a headline this month as a "pipeline in peril."

The Mainline covers 8,760 miles to the largest Canadian markets, once handling 6 billion cubic feet per day.

Over the past five years, TransCanada has seen contracted volumes decline 70 percent and shipments drop to 3.1 billion cubic feet per day, mostly reflecting the decline in conventional production in Western Canada and the rise of shale gas in the northeastern United States.

While TransCanada has acknowledged it is "acutely aware of the competitive situation of the Mainline," Girling said the system has been in place for 60 years and will still be there 60 years from now.

Hopes tied to B.C.

Those hopes are tied to the emergence of shale gas in British Columbia, which TransCanada estimates will see Mainline volumes rebound to 4 bcf per day by 2014, based on secured new contracts for 2.3 bcf per day by 2015 and the prospect of another 2.3 bcf per day over the next decade.

Unhappiness among shippers that Mainline tolls have climbed to C$2.24 per gigajoule this year from C$1.30 in 2006 has led to speculation that some gas buyers in Ontario are recommending the National Energy Board order the shutdown of C$1 billion-C$2 billion of unused infrastructure, resulting in lower tolls — an option that TransCanada refuses to consider.

The company argues that the undepreciated value of the Mainline works out to about C$700,000 per mile compared with the C$4 million per mile it would cost to build a new pipeline (rising to C$10 million per mile in heavily populated areas).

Girling said that even of Mainline tolls were doubled that would be "way cheaper" than embarking on a new pipeline. ●

Contact Gary Park through publisher@petroleumnews.com

XL tug-of-war intensifies

Like it or not, TransCanada is caught in a showdown with no previous parallels as it tries to win over hearts and minds in support of its $7 billion Keystone XL project, while getting dragged into events that are not of its making.

Just as the Calgary-based company had a fleeting chance to enjoy support from an influential source it got sideswiped by the leak of crude oil from an ExxonMobil pipeline in Montana.

An article in the Wall Street Journal contained a ringing endorsement of XL, designed to ship 500,000 barrels per day of crude from the Alberta oil sands to refineries on the Texas Gulf Coast.

It described XL as a "shovel-ready, multibillion-dollar" project that would create 100,000 jobs in the United States, providing economic stimulus at a time when U.S. unemployment is 9.1 percent.

The newspaper argued that if President Barack Obama "were drawing up a plan from scratch to boost union employment and deflate Iranian-ally Hugo Chavez of Venezuela, it might look like Keystone XL."

"U.S. greens loathe oil and the tar sands has become the next Alaska in green mythology. We get that. But what about jobs and growth?" he article said.

But Brian Jorde, an Omaha attorney counseling landowners to reject TransCanada's easement agreements, said a drawn-out legal fight over access to private properties is inevitable, even if TransCanada culminates a three-year wait later this year with a presidential permit from Secretary of State Hillary Clinton.

TransCanada Chief Executive Officer Russ Girling said the Wall Street Journal article was evidence that "some other people" are starting to understand Keystone's benefits.

However, opponents gained fresh ammunition from the Montana spill and a report by University of Nebraska water resources engineering Professor John Stansbury, who accused TransCanada of "flawed and inappropriate assumptions about the frequency and severity" of spills from the XL project, estimating the count at close to 100 over 50 years rather than the company's calculation of 11 spills.

He estimated spills could run to 122,867 barrels in the Missouri River, 165,416

see KEYSTONE XL page 7

EXPLORATION & PRODUCTION

BRPC proposing Putu unit near Nuiqsut

Third unit proposed by the joint venture this year would delineate and develop the Tofkat prospect last explored in early 2008

By ERIC LIDJI
For Petroleum News

A joint venture led by Brooks Range Petroleum Corp. is proposing its second unit in the "billion-dollar fairway" between the Kuparuk River unit and the Colville River on Alaska's North Slope.

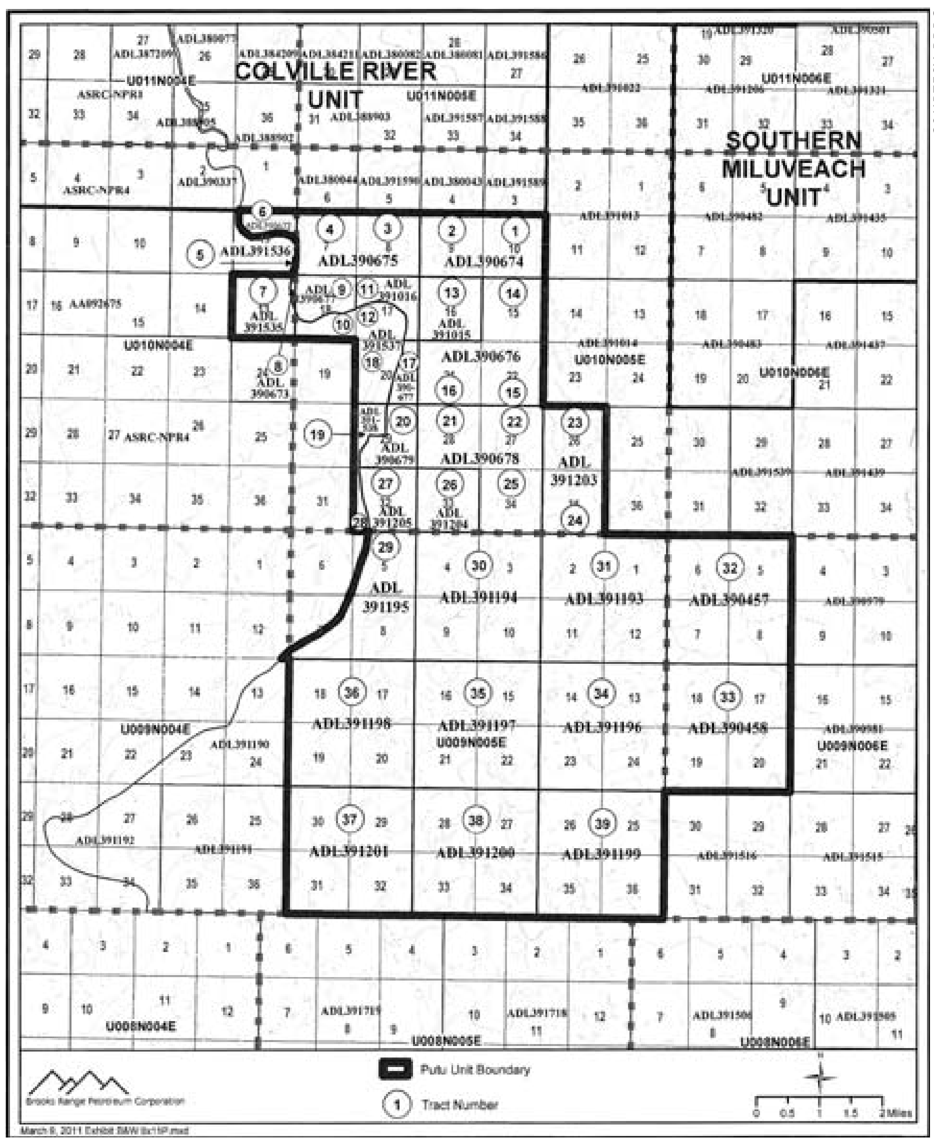
The proposed Putu unit would cover some 39,994 acres over 28 leases, of which 11 are owned by the State of Alaska and 17 are owned jointly by the state and Arctic Slope Regional Corp.

That area abuts the village of Nuiqsut and in 2007, Brooks Range and its partners negotiated a surface access agreement with the Kuukpik Corp., the local Native corporation, making it one of only two companies to have negotiated such an agreement.

The proposed five-year term would run through March 31, 2016.

The joint venture includes Alaska Venture Capital Group LLC (the Kansas-based parent company of Brooks Range), Brooks Range Development Corp. (the local development affiliate of Brooks Range), TG World Energy Inc. and Ramshorn Investments Inc.

The Alaska Department of Natural Resources is taking comments on the proposal through Aug. 18.



COURTESY BRPC

Six-well exploration plan

The companies began acquiring leases in the area in 2003.

Brooks Range told DNR that the working interest owners have spent "well over" $25 million to date exploring the proposed unit area.

That includes a major exploration campaign in early 2008, when Brooks Range and its partners drilled the Tofkat No. 1 well and the Tofkat No. 1A and 1B sidetracks and acquired more than 220 square miles of 3-D seismic, covering the entire proposed unit.

That exploration work identified "many potential hydrocarbon accumulations and additional prospects." Brooks Range is now proposing the Tofkat development project to target a Kuparuk formation reservoir discovered during the 2008 drilling campaign.

If the project is sanctioned and successful, Brooks Range could rent space on the nearby Colville River unit facilities, but as of now the company plans to build independent processing facilities to connect any production to the common carrier Alpine Pipeline.

That exploration work identified "many potential hydrocarbon accumulations and additional prospects."

Production possible by 2015

Brooks Range is proposing to have permits in place for the Tofkat development project by the end of 2013 and to apply for the formation of a participating area by the end of 2014, and projected that it could begin production from the unit as early as July 2015.

Because it would use that production center to improve the economics of other potential accumulations, Brooks Range is also proposing a six-well exploration campaign.

In its unit plan, Brooks Range divided the unit into three exploration blocks and proposed to drill a well in each by the end of March in 2013, 2014 and 2015, respectively. Alternately, Brooks Range could localize those wells if drilling results concluded that focused delineation would be more beneficial than broader exploration in the short term.

The company would then apply for a second unit plan by April 2016 and proceed to drill three more wells by deadlines at the end of March in 2017, 2019 and 2021, respectively.

Currently, the priority for those wells is:

•The Kuparuk formation in the North exploration block;

•The Kuparuk formation in the Southeast exploration block;

•The Alpine formation in the Southwest exploration block; and

•The Alpine formation in the Southeast exploration block.

A preliminary work plan for the winter of 2012 and 2013 involves site preparation, building a 1.5-mile ice road from the annual Alpine ice road to the drilling site and building an ice pad, drilling a Tofkat No. 2 well and possibly performing a flow test.

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PUTU UNIT

Previous drilling found oil

Originally known as Titania, Brooks Range began calling the prospect Tofkat in 2007 to avoid confusion with a similarly named ConocoPhillips exploration program.

Phillips Petroleum originally included Titania/Tofkat as an extension of the Colville River unit in 2002, but never drilled at the prospect and allowed the unit to contract.

Brooks Range ultimately drilled Tofkat No. 1 to 13,174 feet.

Log analysis of the Tofkat No. 1 well showed an interval of 10 feet of gross pay and between four and six feet of net pay, the joint venture told Petroleum News in April 2008.

The companies ultimately took 10 oil samples from four sandstone reservoirs, finding:

•22.9-24.0 degree API oil in the Brookian Topset 1 at 6,128 feet;

•13.4-14.7 degree API oil in the Brookian Topset 2 at 6,294 feet;

•36.6-38.2 degree API oil in the Brookian Turbidites at 11,000 feet; and

•41.8-42.0 degree API oil in the Kuparuk zone at 11,943 feet.

The deepest Kuparuk zone showed properties similar to oil in the Kuparuk Nanuq field, partner TG World elaborated in May 2008. The Brookian Turbidite zone "appears to be in a low porosity reservoir where penetrated," but the formation "is productive in nearby fields where better sandstone facies are developed," the company wrote in a statement. Finally, "the heavier oil properties for the two shallower reservoirs are characteristic for the North Slope" but the "sands were in low porosity reservoirs where penetrated, but are productive in nearby fields where better sandstone facies are developed," TG World said.

Moving toward development

Brooks Range and its partners are clearly in the process of expanding their scope from an active exploration outfit to a potential producer across numerous North Slope assets.

Brooks Range and its partners are clearly in the process of expanding their scope from an active exploration outfit to a potential producer across numerous North Slope assets.

Although the company does not yet have production in Alaska, it currently operates one unit and is waiting for approval on another three. The joint venture formed the Beechey Point unit in 2009 over its leases in the Gwydyr Bay area north of the Prudhoe Bay unit and since the start of 2011, the companies have proposed three additional units:

•The Southern Miluveach unit over its North Tarn No. well one mile northeast of Putu;

•The Greater Bullen unit over its undrilled acreage south of the Point Thomson unit; and

•The newly proposed Putu unit over its Tofkat prospect along the Colville River. ●

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PIPELINES & DOWNSTREAM

Alyeska restarts line after maintenance

Alyeska Pipeline Service Co. said July 17 that it safely restarted the Trans Alaska Pipeline System following a planned maintenance shutdown of the 800-mile oil pipeline system which runs from Alaska's North Slope to Valdez.

Major projects included work at Pump Station 4 south of Prudhoe Bay and at Pump Station 11 (now the Glennallen response base) near Glennallen.

At Pump Station 4, the company said, a 48-inch diameter 62,000 pound valve and a 36-inch diameter 26,000 pound valve used to redirect the flow of crude oil inside the pump station were replaced as part of planned maintenance. The valves are part of the system that enables the station to receive and launch inline cleaning and inspection devices known as "pigs."

Near Glennallen, at the Pump Station 11 site, piping to accommodate a pump station was installed as part of original construction but the pump station itself was never built. During the shutdown, the legacy pipe and valves were replaced with new "straight line" pipe to eliminate the potential for corrosion in the unused "dead leg" piping.

Other work included maintenance work on several mainline valves and work at several pump stations and the Valdez Marine Terminal, including valve maintenance, annual electrical system maintenance and inspections, and modifications to the LEFM (leading edge flow monitoring) equipment at pump stations 3, 8 and 11.

Mike Joyner, Alyeska's senior vice president for operations, called the work "an outstanding example of flawless operations and maintenance and a fine demonstration of TAPS teamwork." Alyeska said the major shutdown, the only one this year, was set to last 36 hours and was completed ahead of schedule.

Alyeska operates the 800-mile trans-Alaska oil pipeline for owner companies BP Pipelines (Alaska), ConocoPhillips Transportation Alaska, ExxonMobil Pipeline Co., Unocal Pipeline Co. and Koch Alaska Pipeline Co.

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KEYSTONE XL

barrels in the Yellowstone, 140,950 barrels in the Platte and 198,000 barrels in the Sandhills region of Nebraska.

Friends of the Earth spokesman Alex Moore said the assurances from TransCanada about its emergency response plan "do not stand up to scrutiny," arguing due diligence is required before construction starts.

Those arguments were bolstered when ExxonMobil's Silvertip Pipeline released 750 to 1,000 barrels of crude into the Yellowstone on July 1.

However, U.S. State Department spokeswoman Wendy Nassmacher said Silvertip is buried only 5 to 8 feet below the river bottom, while TransCanada's plans call for buying XL 30 feet beneath the river bed.

In addition, Montana Gov. Brian Schweitzer, an XL supporter, said the pipeline "is a completely differently designed system" and would have no physical contact with the water.

"Unless people are willing to park their cars and move into a cave and eat nuts, we're going to continue to produce energy and that energy needs to be moved to the source of consumption," he said.

—GARY PARK

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● NATURAL GAS

Storage a game changer for gas industry

More than 450 storage sites in Lower 48, Canada solve imbalance problem between steady production, demand swings based on weather

By BILL WHITE

Researcher/writer for the Office of the Federal Coordinator

The invisible link that keeps North America's natural gas industry running efficiently lies buried in more than 450 sites across the Lower 48 and Canada.

This unseen — and unheralded — agent is underground natural gas storage, and it underpins the gas industry from production to pipelines to consumers.

Because so much natural gas is stored after production, gas utilities can reliably flow fuel to homeowners' furnaces when frosty winters boost demand for heat. Thanks to gas storage, electricity plants have additional fuel to power their spare generators when sweaty summers cause consumers to crank up air conditioners.

Underground natural gas storage solves the imbalance between relatively constant natural gas production during the year and gas consumption that swings wildly with the seasons.

In the same way that stockpiling water behind dams allowed farming to flourish in parts of the arid West, underground gas storage was a catalyst for impressive growth within the natural gas industry. After innovators learned in the 1950s how to store gas and retrieve it from hollowed-out salt beds and old abandoned oil or gas reservoirs, the gas industry started finding new markets and new ways to use the nuisance hydrocarbon that flowed up from oil wells. As a result, flaring or venting much of the produced methane largely became a practice of the past.

After innovators learned in the 1950s how to store gas and retrieve it from hollowed-out salt beds and old abandoned oil or gas reservoirs, the gas industry started finding new markets and new ways to use the nuisance hydrocarbon that flowed up from oil wells.

One chronicle of the gas industry labels the development of modern storage as among "the most important advances in the industry's history."

A wild imbalance

The chasm between steady gas production and erratic gas consumption can be seen in these numbers:

Last year, U.S. gas production ranged from 60 billion cubic feet a day in January to 64 bcf a day in December, a 4 bcf range from low to high. But consumption varied from 52 bcf a day in April to 92 bcf a day in January, a 40 bcf range. When needed, storage and imports filled the gap between production and consumption.

Because the proposed multibillion-dollar Alaska North Slope pipeline through Canada would carry so much gas — 4.5 bcf a day — some of it likely would need to go into storage at times during the year.

U.S. underground gas storage sites hold a three- to 10-week supply of natural gas, depending on the time of year.

Besides saving spring, summer and fall gas production for the heavy demand months of winter, gas might go into storage for any of these reasons:

• A trader buys gas when prices are lower in hopes of selling it when prices rise.

• A local gas utility parks gas in storage to meet spikes in demand during cold spells.

• A Lower 48 power company holds spare gas in storage to use during times of extreme heat.

Stored gas also gets tapped when unexpected production disruptions occur, such as when a hurricane shuts in Gulf of Mexico wells.

Storage tends to stabilize natural gas prices, easing pressure on prices that might surge when demand is high and plunge when demand slackens.

In all, the Lower 48 had 409 underground storage sites at the end of 2009, with a capacity to hold 4.3 trillion cubic feet, or tcf, of working gas, which is gas that can be withdrawn. (The sites also have "base" or "cushion" gas that stays in place forever to provide the internal pressure needed to flow working gas up wells.) About 2.7 tcf was in storage during the year on average — more during the summer and less in winter. In both late 2009 and late 2010, stored gas topped 3.8 tcf, its highest level ever, raising worry that the country lacked enough storage. Winter demand for gas quickly saved the day, however.

Canada has over 50 storage sites that together can hold up to about 700 billion cubic feet of working gas.

In Alaska, a company led by SEMCO, the parent of local utility Enstar Natural Gas Co., hopes to start up an 11 bcf storage site next year in a depleted reservoir the company is rehabilitating near Kenai. It will be the first open-access gas storage operation in the state. Enstar and regional electric companies plan to use the storage to serve peak demand in the winter, even if the proposed big pipeline from Prudhoe Bay starts delivering gas to Alaskans.

It's common for local utilities to own storage sites in the Lower 48; it gives them peace of mind that they can handle fluctuating demand. Other storage owners include pipeline companies and independent operators.

Natural gas gets stored in three types of underground sites:

• Old, depleted oil and gas fields — by far the most popular form of storage.

• Aquifers — the most expensive site to develop.

• Salt caverns — an up-and-coming storage method.

The storage sites typically are located near gas fields, near population or industrial centers, and/or near major pipelines.

That's why the California sites are near Los Angeles or San Francisco; the Texas and Louisiana sites are near the Gulf Coast fields, petrochemical belt and major gas trunk lines; and many sites lie near the big northern cities of New York, Pennsylvania, Ohio, Michigan and Illinois.

Here's a closer look at the three kinds of gas storage sites.

Depleted reservoirs — the big daddy

Depleted reservoirs are the Wal-Mart of gas storage: They're big, almost everywhere and dominate the industry.

They're also cheaper to develop and expand than alternative storage methods.

The nation's 150-year history of oil development has pocketed the country with old reservoirs that petered out decades ago, particularly in parts of

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GAS STORAGE

Appalachia — a storage-site epicenter.

They're cheaper to develop in part because their geology is well understood already. Storage sites need host rock formations that are porous — rocks bearing tiny pores that can hold gas, like the way a sponge holds water — and permeable — pores that are connected so stored gas can flow up withdrawal wells. The host rock formations also need an impermeable rock layer above the reservoir that will hold the stored gas in place rather than let it leak away. Depleted reservoirs have proven themselves on these points, so the developer has less expense proving the reservoir works for storage.

Depleted reservoirs might also have wells sunk in them and they're likely near pipelines, further easing development costs.

Beyond this, base gas is already present in whole or part. Even though the reservoir is technically "depleted," it still contains lots of gas. What's actually depleted because of past production is the underground pressure that allows the gas to flow. The existence of the base gas means the storage site operator doesn't need to obtain and inject as much gas just to pressurize the storage site. (The normal practice is that customers storing gas pay a fee that over time covers the developer's cost of acquiring base gas.)

Of the nation's 409 storage sites at the end of 2009, 335 were depleted reservoirs. Of the 4.3 tcf of working gas capacity, 3.7 tcf was in depleted reservoirs.

Over half of the Lower 48 states host at least one depleted reservoir gas storage site. Many such storage sites are in Ohio, West Virginia and Pennsylvania, birthplace of the U.S. oil industry.

The mother lode of stored gas lies in the seemingly unlikely locale of Michigan. As 2010 began, one in eight of the Lower 48's depleted reservoir storage sites had a Michigan address, accounting for over one-sixth of the nation's working gas storage capacity in depleted reservoirs.

What makes Michigan special? Beneath parts of the state are formations known as pinnacle reef reservoirs — tall vertical mounds of lime and limestone, coral and other materials, according to one federal report. These reefs are highly porous and highly permeable, making them choice storage sites.

As widespread as depleted reservoir storage sites are, they have an important drawback: The gas stored in them usually can't be withdrawn very fast. That makes them fine for long-haul pipeline owners that tap stored gas for load balancing and supply management. But they're ill-suited to meet the emerging storage trend of delivering gas on short notice.

Aquifers — choice of last resort

Storage in aquifers occurs most often when no depleted reservoirs or salt beds are nearby. Most of the nation's 43 aquifer sites are in Illinois and Indiana.

Aquifers are the most expensive form of storage to create and expand — double the cost of converting a depleted reservoir. Their geology must be tested, wells drilled, pipelines laid and dehydration plants built — dry gas is injected but water can come up with the withdrawn gas. It can take up to four years to develop an aquifer into a storage site, twice as long as developing a depleted reservoir.

Aquifers also have another expensive drawback: Half to three-fourths of the gas injected in them will become cushion gas that might never be retrieved. Most aquifer sites were built when natural gas prices were low, so the cushion gas was relatively inexpensive to lose.

To minimize the chances that fresh water within an aquifer is contaminated, aquifer storage falls under U.S. Environmental Protection Agency rules.

Salt caverns — quick turnaround artists

The hot trend in gas storage is to park the gas in new or expanded salt caverns.

Salt caverns are like the small basketball star who compensates for lack of height with his exceptional speed and agility. Their competitive advantage is that the gas stored in them can be delivered quickly. This makes them ideal holding sites for gas to meet demand surges or emergencies. In some cases, a salt cavern can begin flowing as on an hour's notice, according to naturalgas.org, an industry website. Power companies with gas-fired electricity generators that switch on during peak demand have a particular affection for high-deliverability storage sites.

These numbers illustrate their workhorse productivity: The nation's 35 salt cavern sites could deliver 20 bcf of gas a day as of last year, while depleted reservoirs — with 10 times as many sites and 12 times as much working gas capacity — could deliver just 70 bcf a day, according to U.S. Energy Information Administration data. Straggling in last were the nation's 43 aquifers, which could deliver 9 bcf a day.

To create caverns, developers blast water into salt beds or salt domes. This dissolves the salt, flushes it to the surface and hollows out a chamber. The cavern is as air tight as a space capsule, allowing little injected gas to escape. And the cavern walls have the structural strength of steel, letting them hold up well over time, according to naturalgas.org.

Key drawbacks of salt caverns include their smaller size than the typical aquifer or depleted reservoir, and the amount of injected gas — about one-third — that must be reserved as cushion gas to pressurize the cavern.

The other major drawback is that almost all of the nation's salt caverns lie in Texas and Louisiana, particularly along the Gulf Coast. This geographic isolation limits their usefulness.

A new world for gas

Gas storage has been around for nearly a century, but it's only in the past 60 years that it has caught on in a big way, helping transform the gas industry.

The first successful storage site was developed in Ontario in 1915. By 1930, the United States had nine storage sites in six states. All involved depleted reservoirs.

But the world of natural gas was very different back then from what we know today, where the methane in natural gas heats homes, offices and schools; and fires power-plant generators nationwide.

Methane is the main component of natural gas, but before World War II methane use was confined mostly to local markets near oil and gas fields. Because many big gas fields were located in Texas, Oklahoma and Kansas, far from population centers, the surplus methane was vented, flared or reinjected to push more oil from a reservoir. The real money in natural gas involved extracting and selling its liquids — propane, butane and ethane — that could be used as fuel or chemical feedstock in industry. But liquids comprise just a fraction of the natural gas stream.

World War II changed much in America, including the long-distance transportation of oil and gas. Before the war, tankers carried virtually all of the oil shipped from Texas and Louisiana to East Coast refineries. But after the war began, German U-boats hunted tankers along shipping lanes and knocked down the fleet like ducks in a shooting gallery. The government issued an urgent call for new pipelines, and industry responded. After the war, when tanker sailings were safe again, some of these new long-distance oil pipelines were unneeded and two of them — called Big Inch and Little Inch — were converted to carry natural gas eastward instead.

A gas pipeline building frenzy then ensued.

Gas producers were finding new markets. U.S. natural gas production doubled from 11 bcf a day in 1946 to 22 bcf by 1953. All this new gas created its own crisis. Demand for gas was seasonal. The producers and pipelines had too much gas for some of the year and not enough at other times.

Storage was the solution.

At the end of World War II, about 50 underground storage sites existed in the United States, most of them built during the war. By 1956, the nation had 188 sites — about half the number of today. Depleted reservoirs remained the storage method of choice, but the industry was experimenting with other ways to store gas and gas liquids. They tried abandoned mines. They tried digging chambers out of underground rock formations. Many ideas flopped quickly as too expensive to build or too inefficient — gas would leak away or not enough injected gas could be withdrawn later.

A breakthrough innovation occurred in 1949, when the Sid Richardson Gasoline Co. built and tested a salt cavern at its Kermit, Texas, gas processing plant. The company injected propane and later with-

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EMPLOYMENT OPPORTUNITY

Alaska Department of Revenue
Tax Director

The Alaska Department of Revenue is seeking a dynamic individual to lead the Tax Division. The Tax Director oversees a 125 person division responsible for collection of oil and gas severance taxes, corporate income taxes, fisheries business taxes, and a variety of excise taxes. In addition, the Tax Division is responsible for revenue forecasting and development of state tax and fiscal policy and oversees the State's charitable gaming program. The Director is responsible and accountable for the planning, budgeting, staffing and operation of the division and has substantial responsibility for the determination of policy and for the way in which policies are carried out as they pertain to tax administration.

The preferred applicant should have oil and gas tax and/or industry experience and be able to maintain cooperative relationships with industry, community organizations, and the Legislature; speak effectively before public groups and legislative committees; successfully fulfill the mission of the division; analyze problems and develop solutions; and function independently. A Bachelor's degree in business, public administration, accounting, finance, economics or a related field is required. Previous supervisory experience and a CPA, MBA or Law Degree is preferred. The position is located in Anchorage, Alaska.

Interested applicants should submit a cover letter and full resume, including three references to: Alaska Department of Revenue, Deputy Commissioner, Bruce Tangeman, 550 W Seventh Avenue, Suite 1820, Anchorage, AK 99501 in a sealed envelope marked Confidential. Applicants should fully and succinctly explain their applicable experience and their oil and gas knowledge.

The estimated annual salary for this position is between $110,000 and $150,000, DOE. The last day to apply for this job is August 1, 2011; 5:00 PM Alaska Time. The State of Alaska is an EEO/ADA employer.

● ENVIRONMENT & SAFETY

Pipe fails at BPXA's Lisburne facility

Spill not expected to affect oil production from Alaska's North Slope; breach came during pressure test of newly installed valves

ALASKA DEC

Lisburne Production Center L-1 drill site viewing north at the release point at the pipeline road crossing.

By WESLEY LOY

For Petroleum News

Little if any significant production impact was expected to result from a pipeline spill reported July 16 at BP's Lisburne facility on Alaska's North Slope.

BP Exploration (Alaska) Inc. estimated 50 to 100 barrels of methanol and produced fluids, including an undetermined volume of crude oil, spilled onto a gravel pad and into a freshwater tundra pond.

The spill was said to consist of 60 percent methanol and 40 percent produced fluids.

An 8-inch line in a piping system known as a header ruptured underground at a roadway crossing at the L-1 drill site, situation reports from the Alaska Department of Environmental Conservation said. The spilled fluids came out either end of a casing through which the ruptured pipe passes.

About 2,040 square feet of wet tundra and 4,960 square feet of gravel pad were affected, the situation report said.

The line is used to divert production from wells to a test separator required by regulation, not to transport production to the Lisburne processing facility, BP said.

The pipe failure occurred during a hydrostatic pressure test intended to check newly installed valves.

The line failed after pressure reached 949 psi, the situation reports said. It reportedly was rated for considerably higher pressure, but BPXA spokeswoman Dawn Patience couldn't specify how high.

Incident under investigation

The Lisburne field is a reservoir located within the BP-operated Prudhoe Bay unit. Lisburne began production in 1986.

BPXA subcontractor employees discovered the spill at 3:28 a.m. July 16. The spill was reported to the Alaska State Troopers at 4:05 a.m., the DEC situation reports said.

"While the L-1 drill site will remain shut-in, this incident will not delay the restart condition for the Lisburne Production Center," the DEC said.

Spill responders laid boom, and vacuum trucks recovered 15 barrels of spilled liquids from the tundra.

About 2,040 square feet of wet tundra and 4,960 square feet of gravel pad were affected, the situation report said.

The Lisburne facility had been shut down for maintenance for about a month, and so no production loss was experienced, Patience said.

"While the L-1 drill site will remain shut-in, this incident will not delay the restart condition for the Lisburne Production Center," the DEC said.

The cause of the pipeline failure, and whether corrosion was a factor, remained under investigation, Patience said. Corrosion has been a well-publicized issue for BP since a pair of major oil transit lines sprang leaks in the Prudhoe Bay field in 2006.

"It would be preemptive to the investigation of the L-1 incident to speculate on a cause," Patience said in a July 19 e-mail to Petroleum News. "This investigation is already underway and we will share the results with regulators."

Patience added: "The pressure test was continuously monitored and the spill was detected immediately. The test was terminated and spill response was initiated. The test we were undertaking was in fact an integrity inspection of the pipe and its components. Hydrostatic pressure testing is a common and accepted method for integrity testing and is one of the ways a prudent operator ensures safe and reliable pipeline operations." ●

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● LAND & LEASING

Point Thomson field remains in limbo

Hopes for settlement continue as lawyers for Alaska Department of Natural Resources, oil companies press arguments in Supreme Court

By WESLEY LOY
For Petroleum News

Alaska industry watchers have waited for months for some resolution to the Point Thomson dispute, now parked before the Alaska Supreme Court.

So far, talk that the state and Point Thomson unit operator ExxonMobil are near a settlement of the matter hasn't proven out.

"We are cautiously optimistic that we can resolve this dispute in the near future," Elizabeth Bluemink, spokeswoman for the state Department of Natural Resources, told Petroleum News on July 20.

That's been the official line for quite a while.

Meantime, the lawyers are continuing to joust in court, showing few signs that it's time to shake hands on a deal to settle a matter worth billions of dollars to both sides.

What's more, recent court filings indicate ExxonMobil is not alone in pressing the fight with the state. Chevron, a major stakeholder in Point Thomson, recently dealt a legal blow to DNR.

Point Thomson is a rich oil and gas field on Alaska's eastern North Slope, along the Beaufort Sea coast next to the Arctic National Wildlife Refuge.

Aside from ExxonMobil and Chevron, major stakeholders include BP and ConocoPhillips.

All the companies are fighting in court to prevent DNR from breaking up the Point Thomson unit, which the agency has attempted to do "due to lack of production after three decades of unitization," the state's lawyers pointedly remarked in a June court filing.

The oil companies have had considerable success in defending the unit and its underlying leases. The case is before the Supreme Court because a judge in January 2010 reversed former DNR Commissioner Tom Irwin's termination of the Point Thomson unit, prompting the state to appeal.

The Supreme Court proceedings initially remained static, as the two sides repeatedly asked for time to try to negotiate a settlement out of court.

Now the proceedings appear to be back on track, with the state having filed its weighty opening brief and ExxonMobil on the clock to file its reply brief by Aug. 5.

Chevron enters fray

In the meantime, some peripheral legal skirmishing has broken out.

On June 8, lawyers for Chevron filed a motion asking the Supreme Court to strike part of DNR's opening brief.

Chevron said state lawyers had improperly raised a third legal question for the high court to consider, in addition to the two that the court previously had agreed to review at the state's request.

The state's lawyers argued they had, in effect, posed all three issues in their appeal, and that the questions are "intertwined" in a case that concerns whether DNR had the right to terminate the unit, whether the agency treated the oil companies fairly, and whether their failure to submit what the state considers an adequate plan of development constitutes a "material breach" of the Point Thomson unit agreement.

On June 24, an individual Supreme Court justice ruled in favor of Chevron, striking portions of DNR's opening brief.

Status in the field

Despite the legal cloud hanging over the field, ExxonMobil has drilled a pair of wells at Point Thomson with DNR's permission.

But the Nabors rig ExxonMobil hired to drill the holes was stacked, and no further drilling plans have been announced.

Whether the company's goal of beginning production from Point Thomson by the end of 2014 remains achievable is unclear.

ExxonMobil has pledged a $1.3 billion development to produce 10,000 barrels a day of natural gas condensate from the high-pressure Point Thomson reservoir.

A lot of wheels are in motion for this project, including an environmental impact statement the U.S. Army Corps of Engineers is preparing and ExxonMobil's application for a right of way to lay a new $80 million, 22-mile pipeline to carry Point Thomson liquids production west to the existing Badami pipeline. From there, the liquids ultimately would flow into the trans-Alaska oil pipeline.

The main question, it would seem, is whether the oil companies and the state can come to some understanding as to Point Thomson's ultimate fate. ●

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GAS STORAGE

drew almost all of it with virtually no contamination. And the cavern cost relatively little to build.

Good news traveled fast, and within a year five more salt-deposit storage sites were under way, including one in Michigan, according to an industry history.

Storage allowed the natural gas and gas-liquids industries to blossom. Dry gas production nearly tripled from 22 bcf a day in 1953 to 59 bcf in 1973 as more and more American homes burned gas in their furnaces.

Meanwhile, by the early 1980s flaring and venting of natural gas had plunged by over 90 percent from its 1946 peak.

Future favors salt caverns

Much of today's innovation involves using new technology and techniques that reduce the amount of cushion gas needed, or that extract stored gas faster to meet short-term demands.

Another trend involves who is entering the business once exclusively the domain of pipeline companies and local gas utilities. Storage owners increasingly are businesses devoted exclusively to providing gas storage for a fee.

The storage industry continues to grow as U.S. gas demand rises. Gas consumption last year reached a record 66 bcf a day on average, according to the EIA.

The Federal Energy Regulatory Commission oversees about half of the nation's storage sites — those involved in interstate movement of natural gas. The other sites, connected to intrastate pipelines and local gas companies, answer to state regulators. The Regulatory Commission of Alaska is overseeing the rates charged to use the new Kenai Peninsula storage set to open next year.

A report in June by the Interstate Natural Gas Association of America Foundation, a trade group, forecasts the United States and Canada will need another 589 bcf of working gas storage capacity by 2035, with salt caverns dominating the new capacity. The capital cost would be $4.8 billion (in 2010 dollars).

As was said earlier, the Lower 48 working gas storage capacity was 4.3 tcf in 409 sites as 2009 ended. Since 2000, FERC has certificated 98 new or expansion projects totaling 1.1 tcf of working gas capacity, although not all have been built.

Just this year through June 3, FERC certificated four projects — two in Louisiana, one in Utah and one in Iowa — totaling 100 bcf of working gas capacity. As of a month ago, FERC had six more applications pending.

A report in June by the Interstate Natural Gas Association of America Foundation, a trade group, forecasts the United States and Canada will need another 589 bcf of working gas storage capacity by 2035, with salt caverns dominating the new capacity. The capital cost would be $4.8 billion (in 2010 dollars). ●

Editor's note: This is a reprint from the Office of the Federal Coordinator, Alaska Natural Gas Transportation Projects, online at www.arcticgas.gov/node/621.

GOVERNMENT

BLM asks for wilderness nominations

Secretary of the Interior Ken Salazar wants to build a bipartisan wilderness agenda that can be enacted by Congress. In support of that effort, Bureau of Land Management state offices have been asked to solicit suggestions and recommendations from state and local elected officials, tribes and other federal land managers "on areas that deserve wilderness protection and that have broad support for congressional designation," BLM said July 19.

BLM said the effort is an extension of Salazar's June 10 letter to members of Congress requesting their ideas on "crown jewel" areas of public lands that have strong local support for permanent wilderness protection.

BLM Director Bob Abbey said in a statement that: "The best ideas for conservation come from the ground up, and we hope this effort will help lay a foundation for a bipartisan wilderness agenda in this Congress."

BLM said the effort is an extension of Salazar's June 10 letter to members of Congress requesting their ideas on "crown jewel" areas of public lands that have strong local support for permanent wilderness protection.

The Department of the Interior will submit a list of "crown jewels" that it believes are ready for wilderness designation to Congress this fall, based on input from congressional, state, local and tribal partners.

BLM will also issue updated guidance to its offices affirming Salazar's June 1 secretarial memo stating that BLM will not designate any lands as "wild lands."

—PETROLEUM NEWS

● PIPELINES & DOWNSTREAM

Legislators ask officials about reforms

THE ASSOCIATED PRESS

Legislators questioned federal officials July 15 about their plans to tighten the country's pipeline safety rules following numerous high-profile spills and explosions during the past year, asking whether the lead agency overseeing energy pipelines had been overly cozy with the industry.

The agency's highest concern is public safety, and reform proposals pending before Congress will give the government the authority it needs to prevent accidents, Cynthia Quarterman, administrator of the Pipeline and Hazardous Materials Safety Administration, told a congressional committee.

"Having spent time with the employees within the agency, I know they may have concerns about upper-level leadership but in terms of their commitment to the mission, it is the highest thing on their mind," Quarterman testified at the hearing. "To a person, their concern is the safety of the public."

It will likely be months before investigators determine what caused an oil pipeline to rupture near Billings, Mont., on July 1, spilling about 1,000 barrels of crude into the scenic Yellowstone River. The spill fouled dozens of miles of shoreline and backwaters.

Previous accidents also issue

Committee members also quizzed Quarterman and other panelists about a Pacific Gas & Electric Co. natural gas pipeline explosion last year in San Bruno, Calif., that killed eight people, injured many more and left 38 homes in smoking ruins.

Also mentioned was the rupture of an Enbridge Inc. pipeline in July of last year in southwest Michigan, which spilled more than 800,000 gallons of oil into the Kalamazoo River.

"The industry has been driving policy," said U.S. Rep. Jackie Speier, a California Democrat whose district includes San Bruno. "We've got to make it safe for the consumers, for the ratepayers."

Michigan Republican Rep. Fred Upton, who chairs the Committee on Energy and Commerce, compiled a large list of witnesses including several members of the oil and gas industry, but testimony from ExxonMobil Pipeline Co. was postponed for a second hearing July 21.

Quarterman said the Montana accident has focused her agency's attention on preventing pipeline failures.

She previously said it will likely be August or September before water levels in the river are low enough to exhume the section of damaged pipe responsible for the spill.

It could take two months after that before investigators identify a cause, and her agency won't know for certain how large the leak was until it examines records at the company's control room in Houston, she said at another congressional hearing July 14. ●

EXPLORATION & PRODUCTION

Anadarko gets partner approval for test

Anadarko Petroleum Corp. is returning to the Brooks Range foothills.

The Texas independent recently confirmed that it has received approval from partners BG Group and Suncor Energy to test an exploration well it drilled several winters ago. "We're hoping to get out there this winter to do a stimulated test of the gas zones that we discovered," Anadarko spokesman Mark Hanley told Petroleum News on July 20.

"Out there" is the Chandler No. 1 well that Anadarko began drilling in early 2008 and completed in early 2009 near the Colville River and the Umiat airstrip.

The "rig-less test" will include fracture stimulation work, Hanley said. "We know there is gas there," Hanley said. "Testing will give us a lot more information about how the reservoir and rocks will perform, what kind of flow rates and volumes we can get."

The program was the first to specifically target natural gas in northern Alaska, a region without any major natural gas transportation infrastructure. Anadarko is returning to the area as the state is ramping up its efforts to sponsor an in-state gas line to Fairbanks and Anchorage.

Anadarko is already permitting its return.

The company recently applied for a land use permit from the Alaska Division of Mining, Land and Water to use the Franklin Bluffs staging pad for mobilization efforts.

Anadarko wants to use about 11 acres of the pad from October 2011 to May 2012.

The company eventually plans to build a snow and ice road from Franklin Bluffs, along the Dalton Highway, to the Chandler No. 1 well site near the Colville River.

Anadarko also recently applied for a permit to set thermistor strings along the proposed ice road route. Those would provide real-time ground temperature data that Anadarko would use to determine when the ground is frozen enough for heavy equipment.

—ERIC LIDJI

● LAND & LEASING

Anadarko, Repsol land deals approved

North Slope deal precedes development plans, DNR also OKs various working and royalty interest deals in the Cook Inlet basin

By ERIC LIDJI
For Petroleum News

Anadarko Petroleum Corp. has transferred a 50 percent working interest and 40.5 percent royalty interest in 23 leases to the Kansas-based Alaska Venture Capital Group LLC, according to recent lease reports from the Alaska Department of Natural Resources.

The acreage is among the leases in the Greater Bullen unit that AVCG, through its operating arm Brooks Range Petroleum Corp., is proposing on the eastern North Slope.

Pending partner approval, Brooks Range is proposing the Telemark development project to bring a potential Brookian-age reservoir in the Flaxman sand online by 2015, as well as a six-well exploration program for the proposed unit over the next eight years.

Sun-West Oil and Gas Inc. allowed a single offshore lease off the coat of the Arctic National Wildlife Refuge (1002 Area) to expire.

The leases are south of the Point Thomson unit and expire in January and June 2012.

Repsol deal approved

DNR approved a partnership between two central North Slope leaseholders and the Spanish major Repsol YPF. In March, the Armstrong Oil and Gas subsidiary 70 & 148 LLC and fellow Denver independent GMT Exploration Co. LLC transferred a 70 percent working interest and a 56 percent royalty interest in 157 onshore leases to Repsol.

The 494,211-acre leasehold sits just south of the Prudhoe Bay unit.

Repsol previously announced a $768 million multiyear exploration program to look for relatively low risk conventional oil in the region beginning as soon as this coming winter.

Partners Armstrong and GMT also traded interests in several other Alaska properties.

GMT transferred a 3.33 percent royalty interest in eight leases in the Beaufort Sea to Armstrong CEO Bill Armstrong. In Cook Inlet, Armstrong Cook Inlet LLC transferred various working and royalty interests to its partners at the North Fork unit in the southern Kenai: Jonah Gas Co. LLC, Nerd Gas Co. LLC, Dale Resources Alaska LLC and GMT.

On the North Slope, Sun-West Oil and Gas Inc. allowed a single offshore lease off the coat of the Arctic National Wildlife Refuge (1002 Area) to expire.

Cook Inlet deals approved

In Cook Inlet, DNR's Division of Oil and Gas approved the transfer of the Hanna prospect from independent investor Paul Craig to Houston-based Escopeta Oil and Gas Corp. Craig is transferring 100 percent working interest and 82.5 percent royalty interest in the four-lease prospect.

Escopeta is permitting a 5,500-foot well to test gas-bearing sands at the 6,800-acre prospect located on the west side of Cook Inlet, near the mouth of the Susitna River.

Craig also transferred 5 percent royalty interest in those leases to his company PLC LLC.

Also in Cook Inlet, Renaissance Alaska LLC transferred a 0.375 percent royalty interest in three leases at the offshore Northwest Cook Inlet unit to Seitel Offshore Corp.

Coil Inc. transferred a 0.0625 percent royalty interest in two leases at the West McArthur River unit on the west side of Cook Inlet to individual investor Elizabeth B. Clinton. ●

NOTE: A copyrighted oil and gas lease map from Mapmakers Alaska (www.mapmakersalaska.com/) was a research tool used in preparing this story.

Contact Eric Lidji at ericlidji@mac.com

● LAND & LEASING

DNR issues new info for fall lease sales

By KRISTEN NELSON
Petroleum News

What's changed since the Alaska Department of Natural Resources issued best interest findings for the upcoming Alaska North Slope and Beaufort Sea areawide lease sales?

The U.S. Fish and Wildlife Service designated critical habitat for polar bears in the Beaufort Sea and North Slope areawide sale areas.

An Alaska Superior Court judge ruled in favor of REDOIL (Resisting Environmental Destruction on Indigenous Lands) that preparation of a single BIF violates the Alaska Constitution.

In a July 14 decision, DNR Commissioner Dan Sullivan said the department received substantial new information which justified supplementing the findings for the sales.

And the Deepwater Horizon blew up in the Gulf of Mexico, taking 11 lives, spilling oil into the Gulf and generating a number of investigations and inquiries — not all of which are complete — by federal and state governments.

Best interest findings are issued for 10 years; each year before a sale is held the state solicits substantial new information. The most recent BIF for the Beaufort Sea sale area was issued in 2009; the most recent North Slope BIF in 2008.

In a July 14 decision, DNR Commissioner Dan Sullivan said the department received substantial new information which justified supplementing the findings for the sales.

DNR received comments from the Alaska Department of Fish and Game, from The Wilderness Society and collectively from the Northern Alaska Environmental Center, Resisting Environmental Destruction on Indigenous Lands or REDOIL, Sierra Club, Natural Resource Defense Council, Friends of Alaska National Wildlife Refuges, Center for Biological Diversity, Defenders of Wildlife and Alaska Wilderness League.

The commissioner said in the decision that the state will consider information from the Oil Spill Commission final report to the president, dated Jan. 11, on the Deepwater Horizon explosion and oil spill in the Gulf of Mexico.

Supplements to the findings include notification that a single BIF was found unconstitutional in Alaska Superior Court in February. DNR said it "will comply with the court's decision" in the case brought by REDOIL "unless modified by the Alaska Supreme Court."

Lessees are also advised of the U.S. Fish and Wildlife Service designation of critical habitat for polar bears, and of ongoing review and evaluation by the State of Alaska of information from the Deepwater Horizon investigations and the Alaska Risk Assessment reports.

The commissioner said in the decision that the state will consider information from the Oil Spill Commission final report to the president, dated Jan. 11, on the Deepwater Horizon explosion and oil spill in the Gulf of Mexico. The Alaska Oil and Gas Conservation Commission is reviewing and assessing the adequacy of relevant statutes and regulations following the Deepwater Horizon, and is awaiting completion of a joint investigative report by the Bureau of Ocean Energy, Management, Regulation and Enforcement and the U.S. Coast Guard. AOGCC has public hearings scheduled for Sept. 15.

"As this process develops, new or modified mitigation measures, lessee advisories, or other statutory or regulatory requirements addressing issues such as safety, environmental safeguards, risk management, and reporting standards may be forthcoming," the lessee advisory says. ●

Contact Kristen Nelson at knelson@petroleumnews.com

LAND & LEASING

Potential Alaska state and federal oil and gas lease sales

Agency	Sale and Area	Proposed Date
DNR	Beaufort Sea Areawide	Oct. 26, 2011
DNR	North Slope Areawide	Oct. 26, 2011
DNR	North Slope Foothills Areawide	Oct. 26, 2011
BLM	NPR-A	2011

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

This week's lease sale chart sponsored by:
Geokinetics

GOVERNMENT

Corps extends comments for Umiat EIS

The U.S. Army Corps of Engineers has extended the public comment period for the scoping portion of its environmental review of a proposed road to Umiat.

The Army Corps will now take comments through July 26.

The Alaska District of the U.S. Army Corps of Engineers is currently preparing a draft environmental impact statement for an all-season gravel road connecting the Dalton Highway to oil and gas prospects in the foothills of the Brooks Range Mountains, a project outlined last year by the Alaska Department of Transportation & Public Facilities.

The Army Corps recently completed five scoping meetings — in Fairbanks, Anchorage, Nuiqsut, Barrow and Anaktuvuk Pass — and plans to issue a scoping report this fall.

Comments can be made online at www.foothillswesteis.com/submit-a-comment.

—ERIC LIDJI

FINANCE & ECONOMY

Judge OKs federal settlement with BPXA

The federal government's civil case against BP in connection with the 2006 oil leaks in the Prudhoe Bay field is now closed.

U.S. District Judge John W. Sedwick of Anchorage on July 13 signed off on a "consent decree" settling the suit against BP Exploration (Alaska) Inc.

Under the consent decree, BPXA must wire the Justice Department a $25 million civil penalty, implement an "integrity management program" for its Prudhoe pipeline network, and hire an "independent monitoring contractor" to report to the government on the company's compliance.

The Justice Department in March 2009 sued BPXA on behalf of the Environmental Protection Agency and the Pipeline and Hazardous Materials Safety Administration. The suit asserted claims based on alleged water, air and pipeline safety violations in connection with a pair of oil spills from corroded Prudhoe oil transit lines.

Under the consent decree, BPXA must wire the Justice Department a $25 million civil penalty, implement an "integrity management program" for its Prudhoe pipeline network, and hire an "independent monitoring contractor" to report to the government on the company's compliance.

The company did not admit liability in accepting the settlement.

BPXA operates Prudhoe Bay, the nation's largest oil field, on behalf of itself and partners ExxonMobil, ConocoPhillips and Chevron.

A state civil suit remains pending against BPXA in connection with the spills.

—WESLEY LOY

● NATURAL GAS

Polar LNG applies for pipeline ROW

Pipeline would connect Prudhoe Bay to the site of proposed liquefied natural gas plant in Deadhorse; scheduled for summer 2013

By ERIC LIDJI
For Petroleum News

Polar LNG LLC is applying for a right of way for a North Slope natural gas pipeline.

The above ground pipeline would run 3.8 miles from Flow Station 1 at the Prudhoe Bay unit to the Polar LNG Pad, formerly known as Child's Pad, in Deadhorse, paralleling an existing pipeline running from Flow Station 1 to Drill Site 12 and east to the pad.

That route would cross two unnamed lakes.

The 8-inch pipeline would carry between 36 million and 50 million cubic feet per day to a proposed liquefaction plant. Polar LNG plans build the pipeline between early 2012 and mid-2013, and previously said it planned to build the plant in the summer of 2013.

Fairbanks Natural Gas signed a 10-year supply agreement with ExxonMobil in 2008.

The 8-inch pipeline would carry between 36 million and 50 million cubic feet per day to a proposed liquefaction plant. Polar LNG plans build the pipeline between early 2012 and mid-2013, and previously said it planned to build the plant in the summer of 2013.

Polar LNG, an affiliate of Fairbanks Natural Gas LLC, would eventually truck liquefied natural gas to Fairbanks and North Pole. The current plan is to direct 75 percent of the fuel to Golden Valley Electric Association and the remainder to existing FNG customers.

GVEA turbine can run on gas

Golden Valley Electric Association brought a new turbine online in 2007 at its North Pole plant that currently runs on naphtha, but is designed to also run on natural gas.

Although naphtha is cleaner than other fuels and produced at the Flint Hills refinery located across the street from the plant, it is also tied to crude oil markets and prices.

As currently envisioned, the plant would include three trains producing 255,000 gallons of LNG per day total. The plant could also make up to 12,000 gallons per day of propane.

Around 55 percent of the plant capacity is currently committed and Polar LNG said the excess capacity would be used to expand the natural gas distribution system in Fairbanks.

Fairbanks Natural Gas signed a 10-year supply agreement with ExxonMobil in 2008.

Polar LNG estimated the pipeline will cost around $11 million and will be financed by Pentex Alaska Natural Gas Company, LLC — the company that owns both Polar LNG and Fairbanks Natural Gas — through its majority owner Harrington Partners LP. ●

Contact Eric Lidji at ericlidji@mac.com

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PERSILY Q&A

need to finish the job to see if they can put together fiscal terms to put together with a certificate. It's going to be more difficult than it was three years ago based on the long-term outlook for prices, but North Americans are still going to burn 80 billion cubic feet a day of gas. It's got to come from somewhere. If you can get Alaska gas into that market and still make some money off of it, why not?

Petroleum News: Does it make things easier for you now that you're down to one project to focus on with BP and Conoco pulling the Denali project?

Persily: No. because the permits are the same. Whether you talk to the federal pipeline safety office, FERC, or Fish and Wildlife for permitting, or are looking for data collection needed for the pipe. There was only going to be one pipeline. You still need BP and Conoco the producers.

Petroleum News: What about Shell pulling out of the Mackenzie Valley gas project in Canada? Does that concern you from a market perspective?

Persily: No. That's a smart business decision by Shell. Companies don't throw money at every venture out there. Mackenzie has spent a lot of money, a lot of time. Mackenzie's economics are tougher than Alaska's. Alaska has a producing field out there. The gas comes up. We just have to treat it and stick it in the pipe. Mackenzie has none of the production facilities. A little more than half of the $16 billion will go to production facilities; a little less than half is going to the pipe. With the Alaska project, let's face it, oil is going to carry most of the cost up there. Whether it's airstrips, electrical power, the wells, that's basically been charged off against oil. The Mackenzie project has to cover all that.

Petroleum News: You've noted other developments that speak to demand. Can you discuss those?

Persily: The biggest demand driver in the years ahead is going to be electrical generation. Anytime a utility or power generation company announces they are going to retire an old coal fired plant that builds more demand. The more demand, the better shot Alaska has in getting into a growing market. That isn't the only one. The demand build that is necessary to increase the odds for an Alaska project is not going to come from people turning up the thermostat at home on cold days. It's going to come from long-term purchase contracts from utilities and industrial customers. The truth is, shale gas by holding down prices, even though Alaskans are aghast at the notion, lower prices do build more demand. Not just utilities switching from coal, but the resurgence of petrochemical and industrial users, so if it goes their way and we reach a sweet spot and there is enough demand for Alaska gas to get into there. You certainly don't want demand overwhelming supply because that gets out of balance and prices go too high, and when prices go too high people stop using gas. Certainly there is talk about long-haul truckers and delivery fleet vehicles switching to compressed natural gas. I think there will be more of that, but nothing near the volume you get off power plants. There is a lot of that in countries other than the U.S. If things go well, you're talking about 1 billion cubic feet of demand increase in the next 10 years for compressed natural gas vehicles. Sure it helps. But in the last two years, you've had 4 billion cubic feet a day of increased gas demand for power-generation. That's where the big numbers are going to come from.

> *"I don't see any permit problem that can't be resolved. I think the economics and fiscal terms and the politics are what would stop this project."*
> **—Larry Persily, federal coordinator, Alaska Natural Gas Transportation Projects**

Petroleum News: You helped draft the state's gas storage law and your office recently produced a report on gas storage in the U.S. How important is that?

Persily: Gas storage is essential to Alaska no matter where they get it: Cook Inlet; Prudhoe Bay; Indonesia. There is a huge spike in the winter. You can't open a valve and drain wells any quicker because of a cold day. Storage has been essential to the North American gas supply system. It gives utilities certainty knowing the gas is there. It creates a year round demand and there is a place to sell it year round.

Petroleum News: What were your thoughts on the in-state line report?

Persily: It's very thorough, it's well documented. They did a good job on a short timeframe. Even the report said it's Plan B, but I know a lot of Alaskans view it as Plan A. It does point out that the economics of it are very marginal. More than likely you are going to have to have state investment in it. Again I pose the question: Before you invest billions of dollars on a small line, so small that it's not going to create a need for more exploration on the North Slope and won't produce that much in property tax revenues, why don't you see if you can somehow use that same amount of money, leverage it to get a big line that produces a lot of tax and royalty revenue, cheaper gas tariffs and an immediate need to go out there and look for oil and gas. I understand Alaskans are frustrated, they have been hearing about a gas line since 1968. They've had a series of governors that told them it's coming any day now. Well it didn't come any day now. They are angry; they are pissed off; they don't want to hear it anymore. They want to see something done, and the right to decide when something gets done. It makes sense to have it as an option, to have it ready if Plan A doesn't work out, but realize that it comes at a high cost and has its own problems, too.

Petroleum News: Getting back to the fiscal negotiations with the state, where do you start?

Persily: You do not take out the Stranded Gas Act from the Murkowski administration and say 'OK, boys this is our starting point.' I don't think you do that.

The last time Alaska tried negotiating with producers it was a political disaster of epic proportions.

If you are going to try to convince people of something that is very controversial, very contentious, I don't see why starting with a draft with one of the most unpopular laws, during one of the most unpopular negotiations by one of the most unpopular governors. They meant well with it, but the execution was lacking. Start with a blank piece of paper and see what you can get done.

I don't see any permit problem that can't be resolved. I think the economics and fiscal terms and the politics are what would stop this project.

I don't see myself as an optimist or a pessimist; I'm just a realist. Alaska needs it. Alaska can profit from it. Complaining that it wasn't done yesterday, well we should confront the issues and see if we can get it done tomorrow. ●

Contact Steve Quinn at squinnwrite@gmail.com

Petroleum news

Business Spotlight

Calista has new relations specialist in Bethel

DAISY MAY BARRERA

Calista Corp. said July 14 that it has hired Daisy May Barrera to serve as the Bethel-based shareholder relations specialist. While the corporation's headquarters are in Anchorage, the business center of the state, the management team feels that it is crucial to have an employee based in the Calista region's main hub of Bethel. Barrera will interact with Calista shareholders and both regional and village organizations in the region.

Barrera, a Calista shareholder from Nunapitchuk, is providing assistance to more than 13,000 shareholders and tens of thousands of descendants in the Yukon-Kuskokwim region. Among other duties, she is supporting Calista shareholders and descendants with information updates, including address and status changes. Barrera will also assist shareholders who are executing ANSCA stock wills and stock transfer cases.

Barrera has served as a translator for more than 30 years at local and national levels, has previous experience as an advocate for the Tundra Women's Coalition, held various positions for the Yukon-Kuskokwim Health Corp. including as a behavioral health counselor and corporate training development specialist, and has served as a board member for YKHC and is a graduate of the University of Alaska Fairbanks Kuskokwim Campus and is continuing her education in social work.

STEELFAB announces personnel changes

MICHAEL CASSIDY

EARL RUDD

STEELFAB said July 8 that it has hired Michael Cassidy as logistics manager, in charge of all in-bound and out-bound freight. Cassidy brings over 25 years of operations management experience at Fed-Ex and Wien Airlines to the company.

In addition, longtime employee, Earl Rudd, formerly in shipping and receiving, is now part of the inside sales team at the 80,000-square-foot Post Road location.

STEELFAB has been in business in the same location adjacent to Ship Creek in Anchorage since 1948. STEELFAB's covered work area has increased six-fold from 1988 to more than 80,000 square feet. Indoor fabrication space, including a specialty paint and coating building, contains six 10-ton overhead cranes, five 5-ton overhead cranes and modern equipment to include a computer-guided plasma cutter, shot blaster, beam camber machine, a beam fabrication machine and press brakes.

see OIL PATCH BITS page 21

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

GOVERNMENT

State uses US spills to push CD-5 bridge

The State of Alaska is using recent spills into U.S. waterways from buried pipeline crossings as additional evidence that the U.S. Army Corps of Engineers should reverse its insistence on a buried line for CD-5.

The Corps rejected a proposal by ConocoPhillips to take a crude oil pipeline across the Nigliq channel of the Colville River by bridge, insisting instead on a directionally drilled buried line.

Natural Resources Commissioner Dan Sullivan sent a letter to the Corps of Engineers' district commander on July 20, asking him to take into account the recent spill into the Yellowstone River in Montana and other recent spills from buried pipelines that caused pollution in U.S. and Canadian waterways.

"We have long believed that the basis upon which the Corps and the U.S. Environmental Protection Agency rejected the CD-5 bridge permit was erroneous," Sullivan said in a statement after signing the letter.

Sullivan called the decision "part of an unfortunate pattern of shutting down resource development in Alaska."

"The state has recently provided compelling evidence that the Corps' recommended approach to the CD-5 project is not the least environmentally damaging, practicable alternative. Recent events in the Lower 48 further substantiate the state's view."

The Corps is reconsidering its decision rejecting a bridge and aboveground pipe crossing from CD-5 in the National Petroleum Reserve-Alaska. The project would be the first production from NPR-A.

—PETROLEUM NEWS

FINANCE & ECONOMY

Judge tosses RICO claims against BP

A federal judge on July 15 threw out racketeering claims by the lead plaintiffs suing BP over last year's oil spill, and he gave the company another win by setting aside claims filed by one of BP's partners in the well project that resulted in the disaster.

Gulf residents and businesses alleged that BP defrauded regulators in connection with the safety of its drilling operations, its ability to respond to any oil spill, and its response to the actual spill. The Racketeer Influenced and Corrupt Organizations Act, or RICO, was originally enacted to combat the Mafia.

U.S. District Judge Carl Barbier in New Orleans dismissed the claims, saying there is no proof the plaintiffs were directly harmed by the alleged racketeering. The decision does not affect other damage claims still pending against BP and others from the same plaintiffs. A trial is scheduled for February to determine whether Transocean can limit what it pays claimants under maritime law and to assign percentages of fault to Transocean and other companies involved in the disaster.

Also on July 15, Barbier set aside a lawsuit filed against BP by one of its partners on the ill-fated well. He stayed Anadarko's claims because its contract with BP required arbitration of such disputes, rather than litigation. BP was the majority owner of the well that blew out. Anadarko owned a minority stake. Transocean owned the rig that BP was leasing to drill its Macondo well a mile beneath the Gulf of Mexico.

Eleven workers were killed when the Deepwater Horizon rig exploded off Louisiana on April 20, 2010, leading to the worst offshore oil spill in U.S. history.

—THE ASSOCIATED PRESS

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OIL PATCH BITS

Alliance announces Kenai Chapter golf tournament

The Alaska Support Industry Alliance said July 6 that its Kenai Chapter will be holding its annual Golf Tournament Saturday, July 30, 8 a.m. at the Kenai Golf Course.

Registration for this event includes tournament play, hole contests, beverages and snacks, as well as gift packages. An awards banquet will be held following the tournament at Paradiso's with food and fabulous door prizes. For more information and to register and show your support for the Alliance Kenai Chapter and the oil, gas and mining industries please visit www.alaskaalliance.com.

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 September.

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2018 CRUCIAL

producers — the suppliers of natural gas — and potential users of the gas. Rocereta said the meeting was covered by confidentiality agreements, so he couldn't talk about individual expressions of interest, "But what I can say is that this estimate that we put together of the total capacity being desired by off-takers is really close to the aggregated numbers that we got after this expression of interest meeting."

And not everyone who attended expressed an interest in taking gas, which indicates, he said, that there's still unmet demand.

Supply agreements will be required, and potential gas suppliers expressed an interest in negotiating gas supply agreements with interested off-takers. Rocereta said the suppliers requested names of contacts within companies, which AGDC will be providing this week.

"So people are actually going to start talking — the people who are really going to make this thing go are actually going to be talking," he said.

Another thing which came out of the expression of interest meeting was that people were interested in longer-term contracts, 10-year plus contracts, which is another encouraging thing, Rocereta said, because without long-term contracts financing won't be possible.

State owns, others operate

AGDC is recommending a state-owned pipeline because that produces the lowest tariff.

But the state wouldn't be running the line, Rocereta said, it would be like the trans-Alaska oil pipeline which is operated for the owners by Alyeska Pipeline Service Co.

The state would finance the line, some $7.52 billion, and the financing would be paid off by the pipeline tariffs, he said.

Fauske said he's gotten a lot of questions about state ownership, and noted that the state owns AHFC, which has returned $1.9 billion; it owns the Alaska Permanent Fund; it owns the Alaska Railroad; it owns Ted Stevens International Airport; it owns the Alaska Industrial Development and Export Authority, AIDEA.

Fauske said that return on pipeline investment is regulated throughout the country at 12 percent.

"Our attitude is, pay yourself the 12 percent, minus from that a smaller fee to have someone come in and manage it and let's say it's a 3 or 4 percent fee. That 8 percent that you've freed up can be used for any public purpose," he said.

And the projected tariff — $9.63 per thousand cubic feet in Anchorage, $10.45 in Fairbanks — compares to current rates of $8.85 in Anchorage and about $23 in Fairbanks, or $30 based on heating fuel.

While the Anchorage tariff is higher than what Southcentral residents pay now, he said the best numbers AGDC has for imported LNG — an alternative source of gas, and one utilities believe they may need within a few years — are in the range of $14 to $18 for a thousand cubic feet.

"So the state's going to invest $7.52 billion, earn 12 percent return on those dollars and at the end of 20 years will have returned to itself $5.2 billion," Fauske said.

If that project were offered as an investment, "I'm going to be the first one jumping on this one, because your partners are going to be substantial and the need's going to be long-term." ●

Contact Kristen Nelson at knelson@petroleumnews.com

continued from page 1

NEW PLAYER

The sale also includes interests in the Cook Inlet Pipe Line Co. and Kenai Kachemak Pipeline LLC.

Chevron will retain its non-operated joint venture interests on the Alaska North Slope and its 1.36 percent interest in the Trans Alaska Pipeline System.

Hilcorp privately held

Hilcorp, founded in 1989, is one of the largest privately held independent oil and natural gas exploration and production companies in the United States. Headquartered in Houston, the company has more than 700 employees and nine operating areas including the Gulf Coast region, the Gulf of Mexico and the Rockies.

Hilcorp operates across the United States, and said in the joint statement with Chevron that it "continues to grow by actively acquiring and exploiting conventional assets while expanding its footprint into a number of new resource plays."

Hilcorp has been recognized for its progressive culture, values and ethics.

For more information about Hilcorp, go to www.hilcorp.com.

Wagoner: Hilcorp enthusiastic

Sen. Tom Wagoner, R-Kenai, said in a statement that he received a call from Hilcorp representatives notifying him of the acquisition.

"Hilcorp is enthusiastic about the opportunities it sees in Alaska, and it has an aggressive plan to invest in required well maintenance and in-field drilling to restore and increase production from existing fields, as well as pursue the many exploration targets it has identified around the Cook Inlet basin," Wagoner said. "Hilcorp's entry into Alaska is further confirmation of the fact that tremendous oil and gas opportunities remain in the basin," the senator said.

Alaska Commissioner of Natural Resources Dan Sullivan said in a statement that he believes the sale bodes well for new exploration and production in Cook Inlet.

While the Kenai Peninsula bids farewell to a longtime corporate neighbor, the commissioner said, with Hilcorp Kenai will gain a company with a strong track record of entering mature hydrocarbon basins and making the necessary investments to produce more oil and gas.

"We are seeing continued interest in the inlet from serious companies. We look forward to Hilcorp's contribution," Sullivan said.

The commissioner noted the department's successful lease sale in the inlet in June and a new oil and gas assessment by the U.S. Geological Survey significantly boosting estimates to undiscovered, technically recoverable gas resources in Cook Inlet.

Hilcorp, which is privately held, did not provide information beyond the joint statement.

The company's website notes that in September 2010, Hilcorp was "named by the Great Place to Work Institute in conjunction with Entrepreneur as the '5th Best Medium Size Company to Work for in America.'"

Hilcorp was recognized by the Houston Chronicle Top Workplaces 2010 as the "Top Midsize Workplace in Houston."

In its April 2011 issue, the Oil & Gas Financial Journal, in an article based on rankings by IHS Herold Inc., listed Hilcorp as the fourth largest U.S.-based private gas producer and the second largest private liquids producer. In 2010 year-to-date production ranked by barrels of oil equivalent, Hilcorp was third with 28,844,901 BOE and 1,788 wells.

'Three guys and a telephone'

Who is this company coming to Alaska?

On its website Hilcorp describes the company's beginnings "as the proverbial 'three guys and a telephone' trying to make a living in the oil and gas business."

Since then, the website says, Hilcorp has grown to become one of the largest privately held E&P companies in the U.S.

The company said its business model, "acquire and exploit," hasn't changed significantly since it was founded in 1989.

In a CEO message on Hilcorp's website, Jeff Hildebrand, the company's founder, president and CEO, cited "world-class employees, legacy assets and a strong balance sheet," as the reasons for the company's success.

"We focus on what we do well," Hildebrand said, listing the company's core competencies as engineering and geological expertise and operational excellence.

He said the company's vision is "to be the premier private energy company in the industry." The company's mission, he said, is "To efficiently develop energy that would otherwise be lost while providing an enjoyable and challenging work environment where long-term personal wealth can be created."

Hildebrand said the company maintains a unique culture based on: "leaders who set a clear, compelling direction; engaged employees who work like owners; open and honest communication; programs that recognize high performance; one-of-a-kind employee benefits."

Long history

Chevron acquired the Cook Inlet assets of Union Oil Company of California in 2005 and both companies have long histories in the basin, demonstrated by early discoveries credited to the two.

Chevron (then Standard Oil Company of California) discovered Falls Creek in 1961, the Beluga River field in 1962, North Fork in 1965, Ivan River in 1966 and Stump Lake in 1978.

Union Oil Company of California, then called Unocal, discovered the Kenai gas field in 1959, Sterling in 1961, Trading Bay and MacArthur River in 1965 and Pretty Creek in 1979.

When Chevron announced last fall, Oct. 12, that its Cook Inlet assets were being put up for sale, the company's Alaska general manager, John Zager said the company was "proud of our legacy and the dedicated and talented workforce that has developed and operated these assets safely and responsibly for many years."

"We believe that finding a company that views the Cook Inlet as a vital, core assets will benefit employees, the community and the state in the long run," Zager said.

The company has a workforce of some 450 employees and contractors in Alaska. ●

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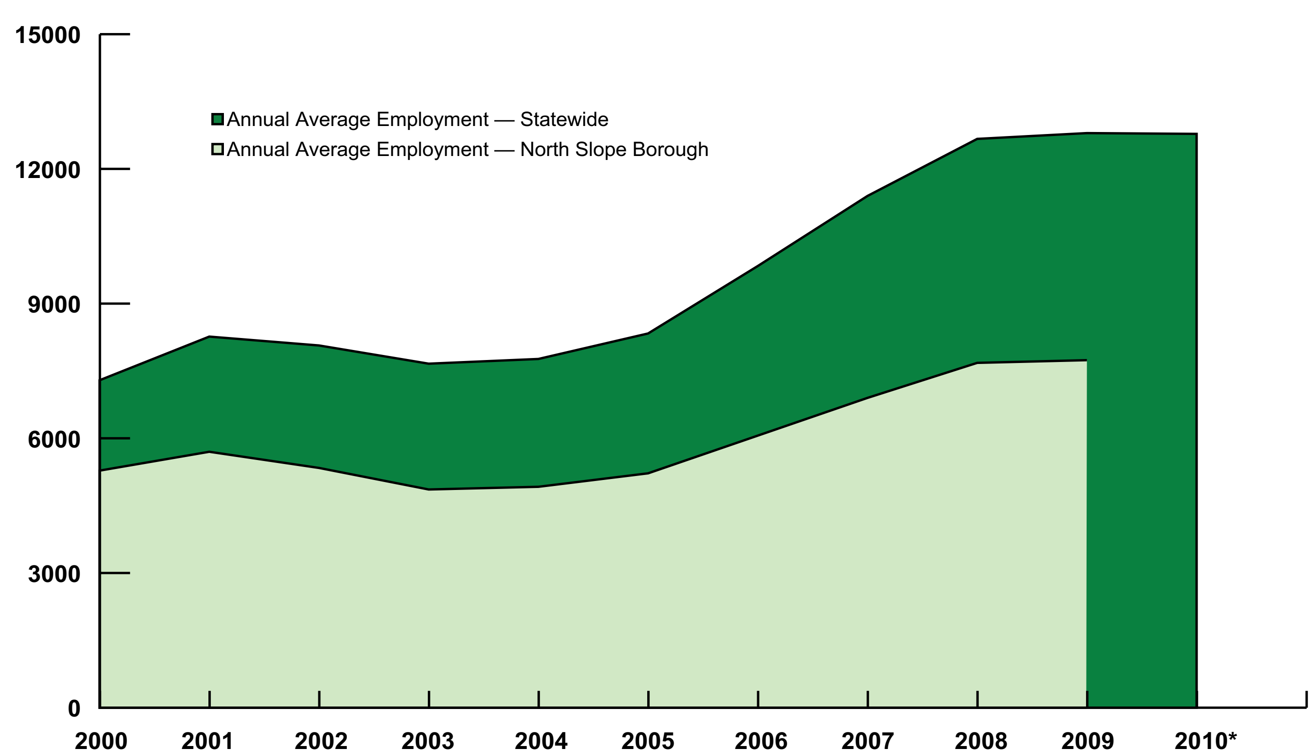
Alaska Statistics

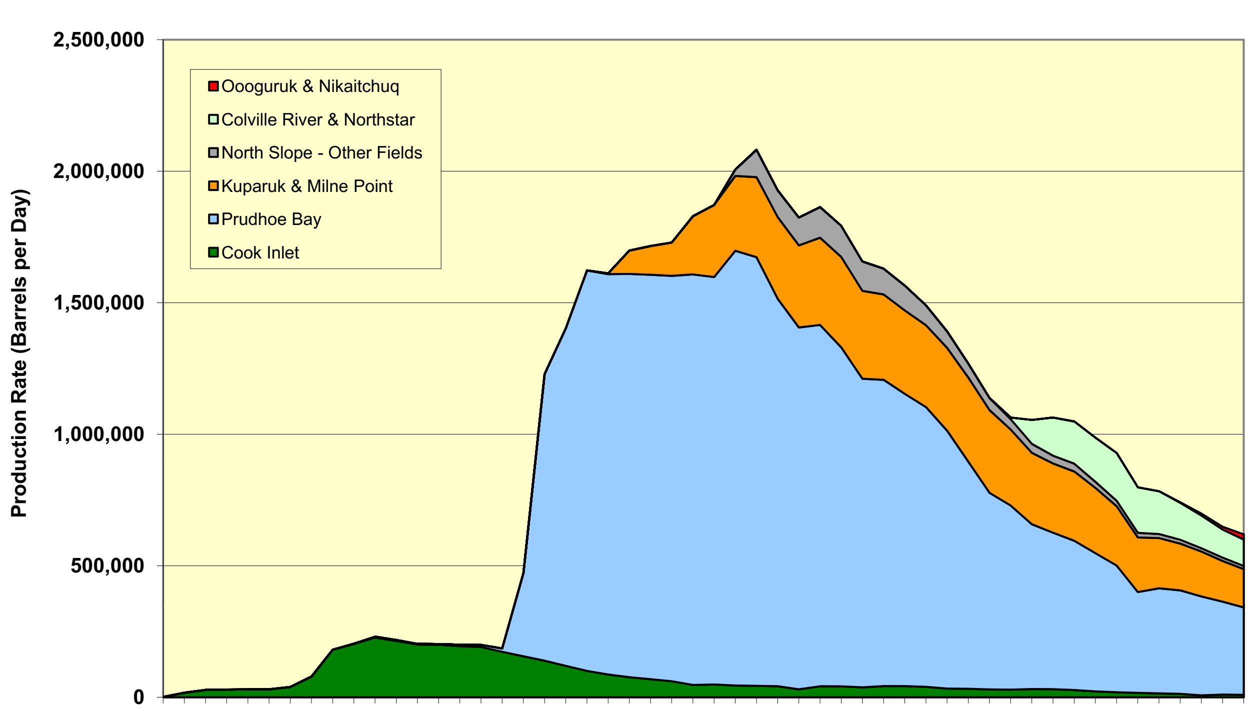
Alaska Oil Industry Employment Statewide and North Slope Borough 2000-2010*



*Preliminary
2010 annual average employment numbers for the North Slope Borough were not available as of the publish date for this chart

Source: Alaska Department of Labor and Workforce Development, Research and Analysis Section and U.S. Bureau of Labor Statistics

Alaska's Average Daily Oil and NGL Production Rate 1960 - 2010



PREPARED BY STEVE DAVIES OF THE ALASKA OIL AND GAS CONSERVATION COMMISSION

Petroleum News will be reproducing this standalone chart from the Alaska Oil and Gas Conservation Commission on a regular basis because of the interest in the decline in Alaska's oil production.

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KENAI LOOP

4.8 million barrels of oil equivalent and the "proven, probable and possible," or 3P, reserves at 51.6 bcf and 6.5 million barrels of oil equivalent.

The company calculated those figures using surface mapping, and pressure and flow rate information from the 10,680-foot Kenai Loop No. 1 that Buccaneer completed in May.

The reserves totals are based on two sands, one at 9,700 feet and another at 10,000 feet.

Second well this quarter

Buccaneer plans to drill Kenai Loop No. 2 this quarter, a step-out well from the same location as Kenai Loop No. 1. Buccaneer hopes it can increase the reserve estimates for the prospect by testing the aerial extent of the two productive sands and by testing the sands below 10,000 feet that Buccaneer believes resemble those two shallower sands.

The spud date for that well is currently dependent on Buccaneer securing a rig.

Buccaneer Director Dean Gallegos said in a statement that as part of the company's three-prong strategy, Buccaneer plans an aggressive drilling program "for the development of the Kenai Loop field and expects to drill additional wells in the next 12 months."

"We anticipate placing the Kenai Loop field into production by the end of 2011," he said.

Kenai Loop is north of the Cannery Loop unit and the city of Kenai, on 8,988 acres of state, Cook Inlet Region Inc. and Alaska Mental Health Land Trust leases in the area.

Buccaneer recently arranged an institutional placement to raise $14.5 million for its onshore and offshore exploration and development program in the Cook Inlet.

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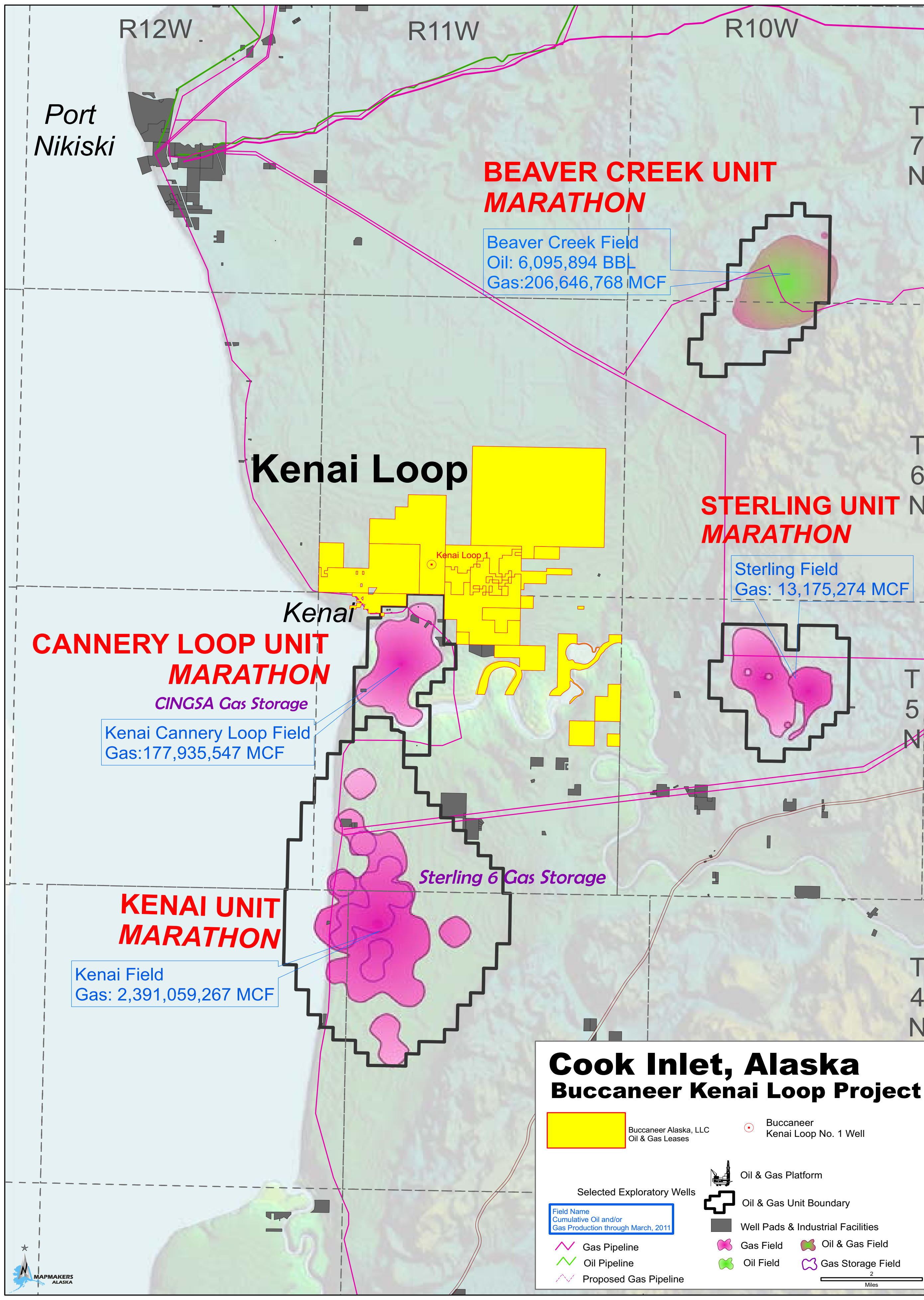

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COURT RULING

also for the exploration, development and transportation phases of oil and gas projects — activities they contend can jeopardize subsistence hunting and fishing.

Organizations challenging the DNR include REDOIL, or Resisting Environmental Destruction on Indigenous Lands; the Gwich'in Steering Committee; the Alaska Wilderness League; the Center for Biological Diversity; and the Northern Alaska Environmental Center.

The DNR petitioned the Supreme Court to review and reverse the judge's ruling, and the high court has accepted the case.

An unnecessary burden

Lawyers for the state argue Peter Ashman, Superior Court judge pro tem, got it wrong.

They say DNR has no constitutional or statutory obligation to write extra best interest findings for post-lease phases of oil and gas projects.

Further, the state lawyers argue that the state already does review these phases to make sure they're consistent with the public interest and don't, for example, harm fish and wildlife habitat. Before any operations can proceed on leased state

see **COURT RULING** *page 24*

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SHELL OUT

percent ownership of the 3 tcf Taglu field, and ConocoPhillips and ExxonMobil Canada with 15.7 percent and 5.2 percent respectively through the 1.8 tcf Parsons Lake find.

In addition, the Aboriginal Pipeline Group, which owns no gas in the region, has an option to secure a 33.3 percent equity stake if it can obtain matching gas volumes from independent producers for the proposed Mackenzie Valley pipeline.

Shell making data available

Shell said it is making relevant data, including its interests in Niglintgak, seven other pools and the pipeline, available to a "broad group of prospective purchasers."

It promotes the Delta in its sales documents as "an exciting, basin-opening opportunity that provides a gateway to the Beaufort Sea and is important for economic development in the Canadian Arctic."

"However, as part of its regular global portfolio review, Shell has decided to focus its resources on other options."

What is unclear is whether the Shell review will have an impact on its successful combined bids of C$43.4 million in June for 100 percent of three parcels in the Central Mackenzie Valley of the Northwest Territories.

Strong hints of Shell's wavering on the MGP emerged four years ago when Royal Dutch Shell acquired the remaining 22 percent share of the Canadian operations it did not already own.

Adrian Loader, Shell Canada's "caretaker" president at the time, said there would be a comprehensive review of all Canadian activities, including the MGP.

That was a shift from earlier support for the MGP from Shell Canada's last chief executive officer, Clive Mather, who said the fundamentals of bringing the stranded gas to market and opening up a new supply basin were "strong," although he conceded the challenges of making an investment decision were "going to be tough."

Shale gas erodes confidence

However, his observations preceded the sudden explosion of interest in developing North America's vast shale gas resources, which has further eroded confidence in the MGP. Partly as a result of seven years of regulatory reviews that cost an estimated C$1 billion, MGP costs are expected to be higher than the last official price tag of C$16.2 billion.

The decision to pull out comes only three months after the MGP received approval from the Canadian government, giving the proponents until December 2013 to decide whether they will proceed with a commercial development.

Still to be negotiated are a fiscal regime with Ottawa and a benefits-and-access agreement with the Dehcho First Nations.

None of the remaining MGP partners has shown any interest in bidding for the Shell Canada assets, although APG chairman Fred Carmichael told reporters said his group is "not really concerned" about the outcome of the sales process.

He said the APG believes there will be "plenty of interest from companies out there who would love to step up to the plate and take over."

One contender could be Korea Gas Corp., which has made a C$30 million investment in the gas holdings of MGM Energy, which include a significant discovery license awarded for the Umiak find.

Officials of the Korean state-owned company have indicated they are prepared to study the economics of shipping LNG from the Canadian Arctic, based partly on predictions of a longer open-water season in the Beaufort. ●

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COURT RULING

land, a company must win DNR approval of a plan of operations. The DNR also reviews and approves unit agreements and plans of exploration and development.

Requiring a written best interest finding for every phase of an oil and gas project would burden DNR, invite lawsuits and "may significantly hinder DNR's ability to permit oil and gas development," the department's lawyers wrote in their Supreme Court petition.

Judge Ashman held that a single best interest finding prior to lease sales, when it's impossible to assess the "cumulative effects" of development, violates Article VIII of the constitution, which deals with use of the state's natural resources.

State lawyers, however, argue the judge found a phantom mandate in Article VIII.

"Nowhere in Article VIII does the term 'best interest finding' appear," they wrote.

The requirement for such findings before "disposal" of state land — that is, leasing — actually is found in Alaska statutes, the state lawyers note. And one statute says state officials "need only prepare a single written finding."

DNR will comply

But Ashman seemed to question the validity of that statute, concluding that the Legislature "is not empowered to enact a statute which would relieve DNR of its ongoing duty to consider best interests of the state at every phase of any project."

Lawyers for the Native and environmental organizations argue post-lease industry activities such as water withdrawals, geophysical exploration and pipeline construction "effectuate the disposal of state land," and in fact have far greater impacts than the "paper transaction" of issuing a lease.

DNR's perspective is very different. It argues it shouldn't be required to comply with "an amorphous constitutional duty when no such duty exists."

Subjecting DNR to a constitutional duty that differs from what the Legislature has prescribed "has the potential to raise long-term uncertainty about the validity of DNR's procedures and to delay exploration activities," state lawyers wrote in their Supreme Court petition. "Given the importance of oil and gas production to state coffers, the uncertainty and resulting delay would be harmful to the public interest."

Ashman remanded the case to the DNR, ordering the department to conform to his ruling.

On July 14, DNR said it would comply with the ruling "unless modified by the Alaska Supreme Court." ●

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