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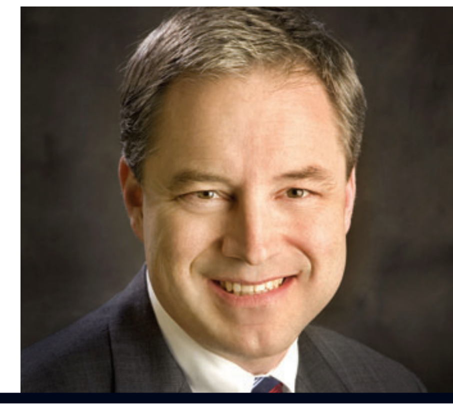


page 4 Q&A: Parnell seeks oil tax changes, more access to federal lands, water

ALASKA VOLCANO OBSERVATORY

Ormat Technologies Inc. is exploring for geothermal energy on the southern flanks of the Mount Spurr volcano, about 80 miles west of Anchorage, Alaska.

Ormat confirms Spurr geothermal; needs utilities to purchase power

Ormat Technologies' summer 2010 small-bore drilling program on the southern flanks of Mount Spurr volcano, on the west side of Alaska's Cook Inlet, has confirmed the likely existence of a geothermal source that would enable power generation for the Alaska Railbelt, Paul Thomsen, Ormat's director of policy and business development, told the Alaska House Resources Committee Jan. 24.

Thomsen said that the purpose of the company's drilling program is to determine whether there is an appropriate combination of underground heat, underground water and permeable rocks to enable the construction of a viable geothermal power plant.

And so far things look good.

Encouraging

"Results to date have been very encouraging," Thomsen said. "The shallow water shows the mixing of geothermal fluids. The geochemistry indicates that there is a very high temperature resource — we can look at water molecules and see how hot they've ever been. All of this is indicating, as we thought, that this is a very hot, very good potential geothermal resource."

Ormat picked up 15 leases on the southern flanks of Mount Spurr in the State of Alaska's September 2008 geothermal lease

see **SPURR GEOTHERMAL** *page 17*

Shell defers drilling plan to 2012; still needs air quality permit

Faced with continuing permitting uncertainty following the Environmental Appeals Board remand of the U.S. Environmental Protection Agency's air quality permit for its planned Beaufort Sea drilling, Shell has abandoned its plan to drill in the Beaufort in the summer of 2011, deferring that plan into 2012.

PETE SLAIBY

"This is not an environmental issue," said Pete Slaiby, vice president for Shell Alaska, in a Feb. 3 media briefing about Shell's drilling decision. "We have made significant and voluntary capital improvements in the air emissions technology we have applied to the entire (drilling) program that will allow us to have almost no material impact on the Arctic air shed. It is an issue of processing a permit application in a timely way. We have been in this process, trying to achieve an air permit, now for five years."

Slaiby said that as a result of the deferral of its Beaufort Sea drilling, Shell expects to farm out in 2011 most of the assets earmarked for the drilling operation.

see **SHELL DECISION** *page 20*

EXPLORATION & PRODUCTION

An explorer, alone

BRPC, partners prepping North Slope's only exploration well for 2010-11

By ERIC LIDJI
For Petroleum News

A multi-company joint venture led by Brooks Range Petroleum Corp. has announced plans to drill what will likely be the North Slope's only exploration well this winter.

The Alaska-based independent plans to start drilling at the North Tarn prospect in early March. The North Tarn No. 1 well site is about two miles west of the Kuparuk River unit.

BRPC plans to drill the well using Nabors rig 9ES.

"We are excited to get started at the North Tarn well and feel that with the signing of the 9ES rig contract, we now have all the contracts in place to effectively execute a successful season," said Bart Armfield, vice president of field operations for BRPC.

"Overall, we have a four-well commitment that we're proposing for that unit, plus a seismic program."
—Jim Winegarner, vice president of land and external affairs for BRPC

The 6,300-foot well would test targets in the Brookian formation and the deeper Kuparuk formation. The Brookian is the same formation producing at Tarn, the Kuparuk satellite to the south, while the Kuparuk is the main formation producing at the

see **BRPC** *page 19*

NATURAL GAS

RCA approves CINGSA

Commission OKs the certificate and tariff for planned Kenai gas storage facility

By ALAN BAILEY
Petroleum News

Just a month or so after approving a certificate of public convenience and necessity for Cook Inlet Natural Gas Storage Alaska's planned Kenai gas storage facility, the Regulatory Commission of Alaska has approved a tariff for the facility.

In a final order issued Jan. 31 the commission said that it was approving the tariff because all issues raised during a tariff hearing had been resolved. Tariff approval is, however, subject to some adjustments to the tariff's specification of the gas storage service area.

CINGSA is fast tracking the development of its facility in the Sterling C sands of the Cannery Loop gas field, on the south side of the City of Kenai, to head off a potential Southcentral Alaska utility gas shortfall in the winter of 2012-13. The

Because CINGSA will not commence gas injection into its facility until April 2012, there is sufficient time for the companies involved in gas storage usage to figure out the required routing of the stored gas and then implement any necessary pipeline infrastructure upgrades, RCA said in its order.

see **CINGSA** *page 18*

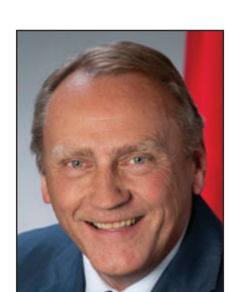
GOVERNMENT

NWT signs for transfer

Agreement in principle with Ottawa; 5 of 7 aboriginal groups not in agreement

By GARY PARK
For Petroleum News

FLOYD ROLAND



JOHN DUNCAN

Two decades of negotiations brought the Canadian and Northwest Territories governments to a signing ceremony that they hope will lead in a couple of years to a final transfer of control over northern natural resources to the NWT, but the gulf between the aspirations of the NWT government and a large portion of its aboriginals remains as wide and deep as ever.

NWT Premier Floyd Roland and federal Indian Affairs Minister John Duncan mustered as much optimism as they could in announcing a "devolution" agreement-in-principle that sets the stage for the NWT to control resource development on public lands and the right to collect royalties and taxes from the resources.

Roland said that much of what Canada's 10 provincial governments have as a matter of constitutional right is what northerners are now close to achieving.

He said the NWT, which occupies about 12 percent of Canada's land mass, is now at a point where it "can progress to a final set of negotiations where a

see **TRANSFER** *page 14*

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Alaska - Mackenzie Rig Report

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

Alaska Rig Status

North Slope - Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Doyon Drilling			
Dreco 1250 UE	14 (SCR/TD)	Prudhoe Bay W-202	BP
Sky Top Brewster NE-12	15 (SCR/TD)	Kuparuk 2L-320	ConocoPhillips
Dreco 1000 UE	16 (SCR/TD)	Prudhoe Bay H-15/01	BP
Dreco D2000 UEBD	19 (SCR/TD)	Alpine CD2-77	ConocoPhillips
OIME 2000	141 (SCR/TD)	Kuparuk 1E-08A	ConocoPhillips
TSM 7000	Arctic Wolf #2	Stacked at Prudhoe Bay	FEX/Available
Nabors Alaska Drilling			
Trans-ocean rig	CDR-1 (CT)	Stacked, Prudhoe Bay	Available
AC Coil Hybrid	CDR-2	Kuparuk 2X-18L1	ConocoPhillips
Dreco 1000 UE	2-ES	Prudhoe Bay Stacked out	Available
Mid-Continental U36A	3-S	Prudhoe Bay Stacked out	Available
Oilwell 700 E	4-ES (SCR)	Milne Point MPF-65	BP
Dreco 1000 UE	7-ES (SCR/TD)	Prudhoe Bay DS 05-30	BP
Dreco 1000 UE	9-ES (SCR/TD)	Going to Southern Miluveach Unit to drill North Tarn #1 on March 1	Brooks Range Petroleum
Oilwell 2000 Hercules	14-E (SCR)	Prudhoe Bay Stacked out	Available
Oilwell 2000 Hercules	16-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Oilwell 2000	17-E (SCR/TD)	Prudhoe Bay Stacked out	Available
Emsco Electro-hoist -2	18-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Varco TDS3	22-E (SCR/TD)	Stacked, Milne Point	Available
Emsco Electro-hoist	28-E (SCR)	Stacked, Deadhorse	Available
Emsco Electro-hoist Canrig 1050E	27-E (SCR-TD)	Stacked at Point Thompson	Available
Academy AC electric Canrig	105-E (SCR/TD)	Stacked at Deadhorse	Available
Academy AC electric Heli-Rig	106-E (SCR/TD)	Stacked at Deadhorse	Available
OIME 2000	245-E	Oliktok Point 0107-04	ENI
Nordic Calista Services			
Superior 700 UE	1 (SCR/CTD)	Prudhoe Bay Drill Site 18-13C	BP
Superior 700 UE	2 (SCR/CTD)	Prudhoe Bay Well Drill Site A-39A	BP
Ideco 900	3 (SCR/TD)	Kuparuk Wel1J-137	ConocoPhillips

North Slope - Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
BP (rig built & being assembled by Parker)			
Top drive, supersized	Liberty rig	Endicott SDI for Liberty oil field	BP
Nabors Alaska Drilling			
OIME 1000	19-E (SCR)	Oooguruk ODST-46i	Pioneer Natural Resources
Oilwell 2000	33-E	Prudhoe Bay Stacked out	Available

Cook Inlet Basin – Onshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Aurora Well Service			
Franks 300 Srs. Explorer III	AWS 1	Stacked out on the west side of Cook Inlet near Tyonek	Available
Cook Inlet Energy			
Atlas Copco RD20 34		Undergoing winterization at W. McArthur River Unit	Cook Inlet Energy
Doyon Drilling			
TSM 7000	Arctic Fox #1	Beluga Stacked	Available
Marathon Oil Co. (Inlet Drilling Alaska labor contractor)			
Taylor	Glacier 1	Rig released by Armstrong Cook Inlet	Available
Nabors Alaska Drilling			
Continental Emsco E3000	273	Stacked, Kenai	Available
Franks	26	Stacked	Available
IDECO 2100 E	429E (SCR)	Stacked, removed from Osprey platform	Available
Rigmaster 850	129	Kenai Stacked out	Available
Rowan Companies			
AC Electric	68AC (SCR/TD)	Stacked Kenai, Cosmopolitan	Pioneer Natural Resources
Kuukpik	5	Stacked, Kenai	Available

Cook Inlet Basin – Offshore

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Chevron (Nabors Alaska Drilling labor contract)			
	428	M-11 Steelhead Platform	Chevron
XTO Energy			
National 1320	A	Coil tubing cleanout planned off Platform A in the near future	XTO
National 110	C (TD)	Idle	XTO

Mackenzie Rig Status

Canadian Beaufort Sea

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

Central Mackenzie Valley

Rig Owner/Rig Type	Rig No.	Rig Location/Activity	Operator or Status
Akita/SAHTU			
Oilwell 500	51	Racked in Norman Wells, NT	MGM Energy Corp.

The Alaska - Mackenzie Rig Report as of February 3, 2011. Active drilling companies only listed.

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

This rig report was prepared by Marti Reeve

JUDY PATRICK

Baker Hughes North America rotary rig counts*

	Jan. 28	Jan. 21	Year Ago
US	1,732	1,713	1,317
Canada	637	621	531
Gulf	26	27	41

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

*Issued by Baker Hughes since 1944

● GOVERNMENT

Parnell: Changes promote jobs, more oil

Governor addresses tax proposals, access to federal lands, prospect of a natural gas pipeline, troubles jumpstarting OCS exploration

By STEVE QUINN
For Petroleum News

Gov. Sean Parnell didn't wait for the Legislature to gavel in before introducing his plan to revamp the state's oil and gas tax structure. He's seeking to lower the 25 percent tax rate on net profits to 15 percent for production from new fields and reduce the surcharge known as progressivity. A few days later in his State of the State address, Parnell stressed additional resource priorities including access to federal lands and waters for resource development. This means collaboration with the industry as well as his peers; he serves as vice chair of the resources committee for the National Governors Association. Parnell sat down with Petroleum News and discussed a wide range of resource issues including oil taxes; the prospects of a natural gas pipeline; the trouble jumpstarting outer continental shelf exploration and production; and stemming the annual 6 percent to 7 percent decline of throughput in the trans-Alaska oil pipeline.

Q AND A

Petroleum News: What are your resource goals for the state?

Parnell: There are several equation changers when it comes to creating more jobs in resource development. One of those is tax regime. The other is permitting. The third is access to those resources. The fourth is accessible affordable energy.

If our administration can change for the better the tax regime and permitting regime, open up access, and create more opportunities for lower cost and lower abundant energy, we can create more resource development jobs.


JUDY PATRICK

GOV. SEAN PARNELL

That's ultimately what I'm trying to achieve. As a state we were supposed to be able to access our resources so we would not become a ward of the federal government. What I can do is focus on state lands and those equation changers or game changers, which is what you'll see us doing.

Petroleum News: Is the end game jobs or is it filling the pipeline?

Parnell: I'm interested in Alaskans having more opportunities. The production aspect comes with that: So greater production means grater revenue, more and better schools and public safety. They are all interconnected. I do tend to think of private sector and economic growth. Then I think about product for the state. I also think about our national security. Having more domestic production is a good thing.

Petroleum News: Can the state afford your tax reduction bill?

Parnell: I don't think we can afford to stand still and cling to a parachute that's only half full. The pipeline will keep working at a certain level. We can all do the math. Unless we get more oil production into that pipeline then we are at risk financially.

The notion that it costs money to do something is misguided because it's a short-term view of things. I understand it comes from legislators who want to spend money right now. I'd rather provide a lower tax environment, and create new jobs, and new production. I'm not looking at the next five, seven, 10 years. I'm looking farther down the road, longer-term.

If the companies' reinvestment is at a level of 50 percent of what they are taking out, the cost to the state is a couple of billion over the next 30 years. If you look out across 30 years and you assume a particular level of reinvestment of those tax credits the cost to the state is minimal compared to thousand or tens of thousands of jobs.

Think of the North Slope. You've got Prudhoe Bay and Kuparuk and they have been punched full of holes — hundreds of wells. There is a lot of acreage that rings those two fields, mostly to the south. It's all leased but it hasn't been drilled for years. Why not take steps to incentivize hundreds of new wells, and thousands of new jobs?

Petroleum News: Why the change of heart? Before you were re-elected you seemed to think ACES was working.

Parnell: Last session I introduced legislation to create infield drilling tax credits along with several other tax benefits because I believed it would create jobs on the North Slope. The Legislature said they were not going to do it for the North Slope. But we'll create tax benefits for Cook Inlet and we have some increased activity for Cook Inlet. What I've said this year has been entirely consistent with that. If there is a demonstration there will be new jobs, new production, we are going to move forward with lower taxes. That's entirely consistent with what I did last year and it's what I want to do moving forward.

Petroleum News: Can this be done in 90 days?

Parnell: Sure it can. I've served in both the House and the Senate. When legislators start talking about a special session on Day 10 (of the regular session), it makes me wonder what's really going on in the background. Legislators can move on jobs for Alaskans if they really want to during the 90-day session.

Petroleum News: Do you have any gas line concerns?

Parnell: Because of the uncertainty of whether a gas line will occur in the next eight or nine years, yeah that's the concern. Any chance I get I push these companies to move together on commercializing Alaska's natural gas, I take it.

Petroleum News: Have you lost any faith in the prospect of getting a gas line built?

Parnell: What I've lost is patience with legislators who think that a $40 billion deal comes together overnight. We've become this government that you order a burger and get it in two minutes. These deals take time to put together. We are still within the time line that AGIA contemplated. Legislators who supported AGIA ought to be willing to give AGIA a chance to work in the timelines contemplated.

Petroleum News: Are you worried shale development affecting Alaska.

Parnell: Certainly shale development can affect gas line economics. As long as the largest companies in the world appear to be seriously pursuing natural gas in Alaska, which is already coming out of the ground, I'm not so worried about shale. Shale is potentially a shorter-term play. New York has already outlawed it. It has its environmental concerns. It takes a lot of capital to punch the holes for shale gas. I think there is room for both. Everything we see says that natural gas will be needed for decades to come. That's a 50-year hori-

see **PARNELL Q&A** page 6

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● ENVIRONMENT & SAFETY

Canada won't lead the way

Environment minister rejects call for independent climate change action, sticks with policy of harmonizing Canadian, US regulations

By GARY PARK
For Petroleum News

Canada is not prepared to "go-it-alone" on a climate change program, despite the urgings of an influential government-appointed panel that Ottawa should proceed independently of the United States by introducing a national cap-and-trade system and set a ceiling price for carbon.

A new report by the National Roundtable on the Environment and the Economy, or NRTEE, said a made-in-Canada approach would allow Canada to achieve significant greenhouse gas reductions over the next decade rather than waiting for the U.S. to act.

But newly installed Environment Minister Peter Kent refused to budge from his government's commitment to harmonize its policies with the Obama administration, which he described as a "sensible and realistic" strategy.

Rejecting the panel's call for a Canadian cap-and-trade system, he said Ottawa has "chosen to move ahead with regulation and we believe that we're seeing early results."

"We believe we will achieve our targets for 2020," Kent said, referring to the federal commitment to lower 2005 emissions levels by 17 percent by 2020.

He said Canada is working with the U.S. on regulations to limit tailpipe emissions from vehicles and is continuing to develop regulations for trucks and is ahead of the U.S. in tackling emissions from coal-fired electricity plants.

Two previous NRTEE reports

The NRTEE, which has issued two previous reports examining the economic risks and opportunities of taking climate change action in Canada, has aligned itself with all three opposition parties in the Canadian Parliament which have criticized Prime Minister Stephen Harper's determination to move in lockstep with the U.S.

Harper has insisted Canada should not make any moves that would weaken ties with its major trading partner.

The Canadian petroleum industry has been especially concerned that independent measures could damage the revival of plans to develop Alberta's oil sands, which account for about half of Canada's crude oil exports to the U.S.

"Harmonization, where possible and when feasible, makes sense for Canada," said NRTEE president David McLaughlin.

"In the face of persistent U.S. uncertainty as to its own climate policy future, Canada will need to look to its own options, in the right way, at the right time," he said.

NRTEE chair Bob Page said Canada needs to "understand how we can meet our environmental responsibilities as a sovereign state ... fully comprehending the unique economic ties we enjoy on this continent. We are looking towards conformity in purpose, not uniformity in detail."

Call for phased-in approach

The NRTEE, in calling for a phased-in approach that would lay the groundwork for greater harmonization as U.S. policies take shape, has recommended action on four options:

• Setting a price collar that limits the Canadian carbon price to no more than C$30 per metric ton of carbon dioxide equivalent higher than whatever price may be set in the U.S.;

• A national cap-and-trade system with auctioning of permits and revenue recycling to cap emissions and address regional and sectoral concerns;

• Limited international permits and domestic offsets to keep domestic carbon prices lower for Canadian companies; and

• A technology fund of up to C$2 billion to stimulate investment in emission-reduction technologies.

The report said it will be more expensive for Canada to reduce emissions than the U.S., partly because U.S. industrial infrastructure and coal-fired power plants are older and will have to be replaced sooner.

Otherwise, if Canada and the U.S. set an identical price, Canada would fall short of matching the U.S. goal for lowering emissions by 2020, the NRTEE said.

Pembina: Report raises questions

Without an independent policy, greenhouse gas emissions would be 10 percent above 2005 by 2020, creating a gap of 178 million metric tons a year between Ottawa's goal and projected emissions, it estimated.

The Canadian petroleum industry has been especially concerned that independent measures could damage the revival of plans to develop Alberta's oil sands, which account for about half of Canada's crude oil exports to the U.S.

The Alberta-based Pembina Institute said the report shows that Canada would see strong economic growth even if it led the U.S. in adopting a broad-based price on greenhouse gas pollution.

Claire Demerse, associate director of Pembina's climate change program, said the report "raises some fundamental questions about the government's long-standing policy of waiting for the U.S. before implementing strong climate policies in Canada."

She said the NRTEE's "detailed and credible analysis shows Canada would see strong economic growth across the country even if we lead the United States in adopting a broad-based price on greenhouse gas pollution."

Demerse said the NRTEE has demonstrated that quick action to introduce stronger climate policies is "both affordable and feasible … (and) there are no credible excuses for delay." ●

Contact Gary Park through publisher@petroleumnews.com

What comes down goes up

The drive by Canadian oil sands producers to reduce their carbon emissions has made headway with per-barrel output from in-situ projects dropping by 15 percent in 2009 from 2008 and from mining projects by 18 percent in 2008 from 2007.

That was the positive spin derived from figures compiled by Evaluate Energy, a London-based source of energy information.

The flip side showed that the rapid growth in production levels also boosted overall emissions by 45 percent in the 2004-2009 period to 44 million metric tons, a total that will continue climbing as production ramps up.

"On a micro level, they have been bringing (greenhouse gas emissions) down, but on a macro level the only direction emissions are going is up," said Chris Wilson, an analyst with Evaluate Energy.

He said that despite the progress being made by producers on a per-unit basis "there aren't going to be any emissions reductions now or realistically any time soon. I don't think this will be acceptable to environmental groups."

Wilson said further reduction gains are possible with the use of new thermal-recovery technologies such as solvent injection and large-scale carbon capture and storage.

Greg Stringham, vice president of oil sands at the Canadian Association of Petroleum Producers, told the Calgary Herald that, even in a worst-case scenario, the oil sands will account for about 9 percent of Canada's overall GHG emissions, compared with 5 percent at present.

However, he said that technologies that are just being brought into full-scale use will continue to drive down the per-barrel intensity of emissions.

"Over the long term, it is wise policy to put a foot in the camp of an industry that is focused on performance enhancement," Stringham argued.

A study by CanOils, the Canadian division of Evaluate Energy, estimated that integrated producers (those who both extract and upgrade bitumen) lowered their average carbon dioxide emissions to 123 kilograms per barrel of synthetic crude in 2009 against 150 kilograms in 2008, while in-situ emissions dropped to 93 kilograms in 2008 from 110 kilograms in 2007.

—GARY PARK

● EXPLORATION & PRODUCTION

BP moves Liberty startup out to 2013

By KRISTEN NELSON
Petroleum News

BP has moved the startup date for its offshore North Slope Liberty project out to at least 2013.

Initial production had been pegged for 2012, and in its "Fall 2010 Revenue Sources Book," published last November, the Alaska Department of Revenue listed Liberty production beginning at 5,000 barrels per day in fiscal year 2012 with production estimated to peak at 39,000 bpd in fiscal year 2013.

The 2013 startup date surfaced Feb. 1 in materials BP presented at its 2010 results and investor update.

Liberty was listed as a project for which the final investment decision has been made, but shown with a startup date of 2013 to 2016.

Steve Rinehart, BP's Alaska spokesman, told Petroleum News in a Feb. 2 e-mail that the 2013 startup date "is a further step along the path we have been following."

He said the last public schedule BP gave for Liberty had drilling beginning in late 2011, with oil production in 2012.

On the Web

See previous Petroleum News coverage:

"BP takes timeout for Liberty rig review; will mean 100 fewer jobs," in Dec. 5, 2010, issue at www.petroleumnews.com/pnads/558437109.shtml

The 2013 startup date surfaced Feb. 1 in materials BP presented at its 2010 results and investor update.

Rig work suspended in November

But in November, "we said we would suspend construction on the rig while we conduct a thorough engineering and design review, and that we would develop a new schedule as that review moved forward."

"The project review is progressing, and our current estimate is oil production could begin in 2013," Rinehart said.

Rinehart told Petroleum News in late November that BP was going to "suspend construction on the rig itself for a period of time," described much of what would be done as "a thorough engineering review" and called it "a decision to move ahead deliberately."

In July BP said drilling would delayed from late in 2011 to "likely" sometime in 2012, after statements by federal and state agencies that they would seek an environmental and safety review of Liberty following the Deepwater Horizon disaster in the Gulf of Mexico.

The 100 million barrel Liberty field is in the Beaufort Sea, some 15 miles east of Prudhoe Bay. Drilling is planned from the Endicott satellite drilling island some eight miles west of Liberty, using ultra-extended reach wells. ●

Contact Kristen Nelson at knelson@petroleumnews.com

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PARNELL Q&A

zon, not a 10- or 20-year horizon.

Petroleum News: What do you do if the companies come to you and say this doesn't pencil out. Do you find any new ways to monetize the gas?

Parnell: I'm open to any ideas when it comes to monetizing the gas. I'm not sitting there waiting. That's whole reason I want to see hundreds of new wells drilled. Alaska needs to monetize all of its resources. Just south of Prudhoe Bay and Kuparuk, that's oil. We should not be standing still and letting that land languish. We should be providing incentives to get new oil production and jobs. There is a lot of oil still left in the North Slope. We are just not going to sit still.

Petroleum News: The state will have spent about $100 million by the end of this fiscal year on gas line reimbursements. Is that money well spent so far?

Parnell: I think so, especially when you consider that Alaska has never been in a place where companies have actually nominated their gas for a gas pipeline. That's the historic nature of where we are. Being in a place where companies are negotiating precedent agreements. That's the historic nature of where we are.

Petroleum News: Let's get back to TAPS (the Trans-Alaska Pipeline System). What are your concerns in both filling the pipeline but also the integrity of the infrastructure?

Parnell: I'm concerned that Alyeska operates TAPS in an environmentally safe and sound way. That being said, one of the best ways to do that is put more oil in the pipeline. It's like your boiler and the hot water lines under your boiler. When you shut down the water, then you have to restart it, you discover the heat from the water helped keep everything sealed. The valves work when everything is flowing full and hot. It's the same thing with a pipeline where you have larger quantities of oil flowing through at greater temperatures. System integrity is not the kind of issue it is when it's down to 300,000 barrels a day or 400,000 barrels a day. That's why my emphasis is putting more oil in the pipeline. It gets hard to maintain at lower flow and lower temperatures.

Petroleum News: With that in mind, some would like to see oil come from the Chukchi and Beaufort. You spoke about federal overreach. Realistically what can you do about that?

Parnell: We cannot afford federal agency overreach that results in fewer jobs and diminished economic opportunity. It doesn't bode well for our future. What I'm seeing is the agencies working to pick states off one by one. I think we're stronger together.

Petroleum News: Does it trouble you that the federal government sold the leases but it's the federal government who won't let them drill?

Parnell: That's the issue. The federal government has a leasing system. Five years later Shell can't even get an air permit that takes months to get in the Gulf of Mexico.

It's kind of a bait and switch by the federal government: to take money on one hand for a lease but not allow lease exploration and development activity.

Petroleum News: You've touched on oil a lot. Do you think the focus moved away from oil for a couple of years in favor of the gas line and now it's shifting back?

Parnell: The question really should be what do we need to do to move forward. We still have a lot of oil to find, a lot of minerals to find and a lot of natural gas. Point Thomson is a priority for me. The first order of priority is more oil for TAPS. What you're seeing is I recognize the value in all resources.

Petroleum News: Talk about Point Thomson. Where would you like to see this by year's end?

Parnell: I'd like to see a settlement, a resolution that's in the state's best interest, and more work in Point Thomson. That's been one of the state's bright spots in exploration activity. I think there is a resolution that's in the state's best interest. At this point I wouldn't call it imminent, but I think it's possible. It's an important key because it holds a lot of gas that's crucial for the pipeline. ●

EXPLORATION & PRODUCTION

Rollercoaster: ANS production back on par

By end of January Alaska North Slope crude oil production almost level with beginning of month, following spill driven shutdowns

By KRISTEN NELSON
Petroleum News

Alaska North Slope production was at 647,255 barrels per day on Jan. 1; by the end of the month it had almost reached that level again, peaking at 646,075 bpd Jan. 30, following shutdowns after a leak was found at Pump Station 1 on Jan. 8, and again mid-month for repairs.

January production numbers from the Alaska Department of Revenue's Tax Division show normal production at the beginning of the month, followed by a steep decline — Alyeska Pipeline Service Co. shut the trans-Alaska oil pipeline down completely for four days beginning the morning of Jan. 8 — and then a shallower dip Jan. 15 when the line was shut down for almost two days for the installation of bypass piping.

Because of the extensive downtime during the month, January average ANS production was 471,666 bpd, down 26.5 percent from a December average of 641,518 bpd.

BP Exploration (Alaska)'s Milne Point field had the largest percentage drop month-over-month, down 33 percent, with a January average of 17,999 bpd compared to 26,874 bpd in December.

The largest per-barrel drop was at the BP-operated Prudhoe Bay field, which averaged 233,259 bpd in January, down 101,670 bpd and 30.4 percent from a December average of 334,929 bpd.

Prudhoe Bay includes satellite production from Aurora, Borealis, Midnight Sun, Orion and Polaris.

AOGCC extended reinjection order

The Alaska Oil and Gas Conservation Commission had authorized BP Exploration (Alaska) to pump crude oil into designated development wells on an emergency basis while the trans-Alaska oil pipeline was unavailable.

The order, issued Jan. 11, was extended an additional two weeks on Jan. 21 because the pipeline was unavailable at full capacity.

In extending the emergency order, the commission said repairs to the pipeline were taking "longer than anticipated," and while Alyeska Pipeline Service Co. had completed installation of a piping bypass the line was "still not operating at normal capacity. In turn, BP cannot operate at normal production," the commission said.

The order allowing BP to pump crude oil into development wells was issued because without the ability to ship oil down the pipeline at normal volumes, "some production must be maintained to protect the safety of operating personnel in the fields and Deadhorse by providing fuel gas" and to prevent damage to production equipment and pipelines from freezing.

The initial order expired after 14 days and the commission said BP requested the extension because the trans-Alaska oil pipeline was still not operating at normal capacity.

—KRISTEN NELSON

All production averages down

The ConocoPhillips Alaska-operated Kuparuk River field had the second-highest per-barrel drop, averaging 101,999 bpd in January, down 27,324 bpd and 21.1 percent from a December average of 129,323 bpd. Kuparuk includes satellite production from Tabasco, Tarn, Meltwater and West Sak, as well as production from the Pioneer Natural Resources Alaska-operated Oooguruk field. Department of Revenue figures do not break out Oooguruk production; the most recent figures available from the Alaska Oil and Gas Conservation Commission are for November, when Oooguruk averaged 8,942 bpd.

The ConocoPhillips' operated Alpine field averaged 70,358 bpd in January, down 16,288 bpd and 18.8 percent from a December average of 86,646 bpd. Alpine production includes the Fiord, Nanuq and Qannik satellites.

The BP-operated Lisburne field averaged 23,824 bpd in January, down 8,221 bpd and 25.7 percent from a December average of 32,045 bpd. Lisburne production includes Point McIntyre and Niakuk.

On the Web

See previous Petroleum News coverage:

"Trans-Alaska oil pipeline up and running," in Jan. 23, 2011, issue at www.petroleumnews.com/pnads/728512344.shtml

"Winter shutdown," in Jan. 16, 2011, issue at www.petroleumnews.com/pnads/951089528.shtml

The BP-operated Northstar field averaged 13,746 bpd in January, down 5,124 bpd and 27.2 percent from a December average of 18,870 bpd.

The BP-operated Endicott field averaged 10,481 bpd in January, down 2,350 bpd and 18.3 percent from a December average of 12,831 bpd.

Cook Inlet crude oil production averaged 9,673 bpd in January, down 8.3 percent from a December average of 10,547 bpd.

The temperature at Pump Station 1 on the North Slope averaged minus 9.7 degrees Fahrenheit in January, compared to minus 11.8 F in December.

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

Contact Kristen Nelson at knelson@petroleumnews.com

NATURAL GAS

Energia Cura names pipeline Arctic Fox

A proposed small gas pipeline from Alaska's North Slope to the state's Interior now has a name: The Arctic Fox Pipeline.

Energia Cura, a Fairbanks-based energy consulting firm and parent to Fairbanks Pipeline Co., said in a Feb. 2 statement that the line was named after Congressman Don Young, R-Alaska, commented that the proposed line would be small, smart and quick.

Energia Cura met with Young Dec. 27 to discuss the value of the line, which would be a small-diameter high-pressure line moving volumes of gas justified for Interior markets.

Energia Cura said it has also met with Mike Nizich, chief of staff to Gov. Sean Parnell, to reiterate a request for a due diligence review of the project and continues to meet with Alaska leaders and others in the industry.

"We have substantiated the viability and profitability of an all-Alaska natural gas pipeline and we openly invite the public and our public officials to review our feasibility study and economic analysis," said Alex Gajdos, FPC co-founder. "We want our public officials to see that that there is a valid alternative to waiting for a big pipe. We can move gas to Alaskans now and prosper by owning the pipeline ourselves. We can get gas to Alaskans now."

FPC said it will continue to provide its documents to interested parties and will continue to post detailed updates on the firm's website, www.fairbankspipelinecompany.com.

Energia Cura has constructed pipelines in Alaska and operates and maintains a pipeline system connecting the trans-Alaska pipeline system to both North Pole refineries.

—PETROLEUM NEWS

GOVERNMENT

Begich introduces Arctic oil spill bills

U.S. Sen. Mark Begich, D-Alaska, has introduced three bills aimed at safe and responsible oil and gas development in the Arctic. The bills would initiate comprehensive Arctic oil spill research and planning; require transport of oil ashore by pipeline; and provide Alaska with revenues from offshore development.

"Arctic oil and gas development is a necessary part of any comprehensive national energy policy which is needed if we are going to reduce our dependence on foreign sources of energy," Begich said in a statement.

SEN. MARK BEGICH

The senator said the U.S. needs to "build the necessary infrastructure and do everything possible to prevent oil spills, but we also need to get moving on our oil and gas development to secure economic and national security."

"And there's absolutely no reason Alaskans shouldn't get their fair share of revenues from our OCS development," he said.

The senator said the U.S. needs to "build the necessary infrastructure and do everything possible to prevent oil spills, but we also need to get moving on our oil and gas development to secure economic and national security."

Versions of the bills were also introduced in the last Congress.

• The Responsible Arctic Energy Development Act directs the National Oceanic and Atmospheric Administration, the U.S. Coast Guard and other federal agencies to conduct research to improve oil spill prevention, response and recovery in the Arctic.

• The Resources for Oil Spill Research and Prevention Act funds Arctic oil spill research and planning efforts by increasing the per barrel contribution to the Oil Spill Liability Trust Fund by 3 cents per barrel for domestic oil and by 7 cents per barrel for imported oil, amounts estimated to raise some $300 million annually.

• The Alaska Adjacent Zone Safe Oil Transport and Revenue Sharing Act secures a share of federal revenues from offshore oil and gas development for the State of Alaska and Alaska's coastal communities equal to that provided to Gulf Coast states from drilling in the Gulf of Mexico. The bill also requires oil produced in federal waters in the Chukchi and Beaufort seas to be brought to shore by pipeline.

—PETROLEUM NEWS

Seamount reappointed to AOGCC

Among appointments submitted to the Legislature for confirmation by Alaska Gov. Sean Parnell on Feb. 1 was Dan Seamount, reappointed as a member of the Alaska Oil and Gas Conservation Commission.

Seamount was appointed to the commission in 2000 and reappointed in 2005.

The term for which Seamount has just been appointed expires in 2017.

Seamount holds the geologist seat on the commission and currently serves as chairman.

—KRISTEN NELSON

JUDY PATRICK

DAN SEAMOUNT

FINANCE & ECONOMY

Weeks wants indie credit extended

Asks Parnell to remove 2016 sunset provision on the Small Producer Tax Credit; credit pays for fields smaller than 50,000 bpd

By ERIC LIDJI

For Petroleum News

A tiny North Slope explorer is asking the State of Alaska to extend a tax credit for small producers.

UltraStar Exploration Managing Member Jim Weeks sent a letter to Gov. Sean Parnell on Jan. 28 asking him to indefinitely extend the Small Producer Tax Credit. Parnell recently proposed a several revisions to the state fiscal regime for exploration and production.

The Small Producer Credit pays up to $12 million per year to companies that produce less than 50,000 barrels of oil equivalent per day (and an increasingly smaller credit for companies that produce between 50,000 and 100,000 barrels of oil equivalent per day).

The credit is set to expire in 2016 (although if a company brings a field online between 2006 and 2016, then the credit lasts for nine years from the start of production).

Weeks believes it should be extended indefinitely.

"Rather than have a specific year when the Small Producer Credit expires, I recommend that it stay in place for each reservoir or unit until payout of the exploration, delineation and development costs necessary to get the oil flowing," Weeks wrote.

Because of the long lead time needed to develop reserves on the North Slope, Weeks hypothesized that companies likely wouldn't get to claim the credit on any production from leases acquired last year. He noted that it took UltraStar, the smallest explorer on the North Slope, six year per well to drill. UltraStar may never get to claim the credit.

Credit dates to Murkowski

The Murkowski administration created the Small Producer Credit in 2006 with the Petroleum Profits Tax, an overhaul of the fiscal regime. The Palin administration kept the credit when it revised the tax code in 2007 under Alaska's Clear and Equitable Share.

The Parnell revisions are popular among independents. A group of six smaller explorers issued a statement saying the bill "addresses the fundamental concerns of all companies that would like to explore for and develop reserves on the North Slope."

The companies are Armstrong Oil and Gas (through its subsidiary 70 & 148), Brooks Range Petroleum Corp. (the operating arm of the Alaska Venture Capital Group), GMT Exploration, Great Bear Petroleum, Savant Alaska and Renaissance Alaska.

UltraStar Petroleum is exploring the Dewline unit north of Prudhoe Bay and south of Northstar. The company drilled the Dewline No. 1 well in early 2009 and is preparing to drill a follow-up well and sidetrack in the winter of 2011 and 2012.

Winstar Petroleum, a sister company to UltraStar run by all the same players, drilled Oliktok Point State No. 1 in 2003, but that well ultimately proved to be a dry hole.

The Parnell bill would lower the tax rate at new fields, cap production taxes and extend some Cook Inlet tax credits to the North Slope, among other proposed revisions. ●

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● EXPLORATION & PRODUCTION

Wilcox: Alaska needs small independents

Co-founder of Cook Inlet Energy says big oil companies open basins, smaller companies needed for smaller geologic opportunities

By KRISTEN NELSON
Petroleum News

J.R. Wilcox, the president and one of the co-founders of Cook Inlet Energy, says Alaska needs small independents to develop smaller geologic opportunities in the state, to keep larger fields producing and basically to keep the lights and heat on after the super majors move on.

Cook Inlet Energy took over fields in Cook Inlet which had been shut-in and has been returning wells to production.

"We're currently producing a proud one-sixth of 1 percent of Alaska's oil production," Wilcox said.

Wilcox told the Alaska Support Industry Alliance's annual Meet Alaska conference in Anchorage Jan. 21 his focus was on the role of small independents — and what the State of Alaska needs to do to encourage small operators.

Wilcox is a fifth-generation Alaskan and said his focus is on the long-term: His great-great grandfather came to Alaska and his focus is on where Alaska will be 100 years from now and what his great-great grandchildren will be doing.

A novelty

The state has a problem to address and "that's that Cook Inlet Energy is a novelty," Wilcox said. "The most remarkable thing about Alaska as an oil basin north of the Mexican border is the almost complete absence of small independents."

JUDY PATRICK

J.R. WILCOX

He said he loves big oil companies because "they can do all the things that small companies can't," from building facilities and pipelines to advancing technology.

"They're the basin openers," Wilcox said.

But there are 8,000 to 10,000 operators producing oil and gas in Texas; in Alaska there are eight, he said. And while super majors account for 10 percent of the oil and gas produced from state lands in Texas and large independents account for another 20 percent, 70 percent of that production is from small independents.

Texas is not an anomaly, he said — the same holds true for states like Oklahoma and Kansas.

"Small producers, while not doing the big sexy projects, are actually giving you your bread and butter production," Wilcox said.

More focus needed

Alaskans tend to focus only on the super majors, Wilcox said: on attracting new investment from super majors to slow North Slope production decline; on bringing North Slope gas to market; on opening federal lands onshore and offshore for development. Addressing those issues involves discussions around a more stable fiscal regime and battling with the federal government for development.

But Alaskans also need to focus on another issue: "How do we create a vibrant class of independent companies?"

Looking into the future, "the most significant thing we can be doing is trying to create a vibrant class of entrepreneurs and the infrastructure that is going to create a state capable of taking advantage not just of the very, very large

see WILCOX page 13

● NATURAL GAS

Legislature gets report on AGIA payments

By KRISTEN NELSON
Petroleum News

The commissioners of the Alaska departments of Revenue and Natural Resources reported to the state Legislature Jan. 28 on reimbursements made by the state under the Alaska Gasline Inducement Act.

TransCanada Alaska Co. LLC and Foothills Pipe Lines Ltd. received the state license under AGIA in December 2008, and in exchange for commitments related to the project schedule, tariffs and future expansions, TC Alaska is entitled to inducements from the state including up to $500 million in matching reimbursements for qualified project expansions.

Reimbursements are at a rate of 50 percent of qualified expenditures prior to the close of the first binding open season and 90 percent thereafter. Qualified expenditures include costs directly and reasonably related to advancing the project, and exclude overhead, lobbying and litigation costs, civil or criminal penalties or fines, or expenditures for assets or work product acquired or developed before the license was issues.

TC Alaska submits expenditures on a monthly basis and requests for reimbursement each quarter.

The Department of Revenue does a due diligence review on the expenditures and a separate, high-level due diligence review if done by the state's technical pipeline monitor.

Delay at end of FY 2010

At the end of fiscal year 2010 (June 30, 2010), TC Alaska was behind in submitting reimbursement expenditures, partly due to the addition of ExxonMobil to the existing reimbursement process. The state and TC Alaska focused on getting the reimbursement current and that was accomplished by the end of October.

In fiscal year 2011, $250,000 was appropriated for development of an AGIA information reimbursement system to improve the collection, tracking, reviewing and reporting of project expenditures. The automated system is expected to be complete this May.

The first annual audit of TC Alaska was completed by Martindale Consultants Inc. in November and covered expenditures reimbursed by the state through the calendar year ending Dec. 31, 2009, which covered four months of activity because of delay in submission of reimbursements.

To date, TC Alaska has been reimbursed some $36.7 million at the 50 percent rate for work submitted through the second quarter of 2010.

Reimbursements

By the end of fiscal year 2010, TC Alaska had been reimbursed some $4.4 million for expenditures submitted through the second quarter of 2009. The state said the addition of ExxonMobil to the project delayed the rate at which TC Alaska could submit expenditures.

To date, TC Alaska has been reimbursed some $36.7 million at the 50 percent rate for work submitted through the second quarter of 2010.

TC Alaska has submitted a total of $92.2 million in gross expenditures for review. The state took exception to $13.8

see AGIA REPORT page 14

● FINANCE & ECONOMY

BP's Carson refinery one of 2 to be sold

Facility near Los Angeles is major processor of Alaska North Slope crude oil; Washington's Cherry Point refinery also uses ANS crude

By WESLEY LOY
For Petroleum News

A major destination for Alaska North Slope crude oil — BP's Carson refinery near Los Angeles — is going on the sale block.

BP announced Feb. 1 it would sell the Carson refinery along with its troublesome Texas City refinery as part of a continuing campaign to divest up to $30 billion in assets to cope with the Deepwater Horizon disaster.

The London-based company said it aims to complete the refinery sales by the end of 2012, reducing its U.S. refining capacity by half. BP said it "expects significant market interest" in the large refineries.

The sale of the two plants "will make BP the smallest refiner among its international competitors," the company said.

But it emphasized it still will have a stable of "higher quality refineries and related marketing networks," and that it plans refinery upgrades.

BP's other refinery assets include the Cherry Point, Wash., refinery, which also takes major deliveries of North Slope crude; the Whiting, Ind., refinery; and a 50 percent interest in the Toledo, Ohio, refinery.

"These refineries have greater flexibility to refine a range of crude oils including heavy grades, and on average are more diesel-capable than BP's current portfolio," the company said. "They are also well-integrated with BP's marketing operations."

Carson refinery specs

BP picked up the Carson refinery through the ARCO acquisition in 2000.

Located on 630 acres near the Long Beach and Los Angeles harbors, the Carson refinery "is at the heart of an integrated fuels value chain stretching across southern California, Arizona and Nevada," BP said.

It supplies 25 percent of Los Angeles gasoline demand and 50 percent of the jet fuel at the LAX airport, a BP fact sheet on the Carson refinery says. The plant employs about 1,200 people.

Carson processes 265,000 barrels of crude oil per day, including Alaska North Slope, Middle East and West Africa crudes. Alaska crude accounts for about 70 percent of the refinery's intake.

Tankers load North Slope crude at the terminus of the trans-Alaska pipeline at Valdez and haul it south through the Pacific for delivery almost exclusively to West Coast refineries.

"The assets associated with the Carson refinery also to be divested include BP's interests in a cogeneration plant on the refinery site, crude and product terminals and also its marketing interests," BP said. "As part of this sale, BP expects to divest the ARCO brand (though retaining brand rights for northern California, Oregon and Washington) and to retain ownership of and license the ampm brand."

Texas City refinery

BP acquired the Texas City refinery in the 1998 merger with Amoco.

It has been a troublesome property for BP, the scene of a 2005 explosion that killed 15 workers.

Located south of Houston near Galveston Island, Texas City is the third largest U.S. refinery, producing 3 percent of the nation's gasoline supply. It runs 475,000 barrels of crude per day, and in 2009 processed 54 different types of crude from all over the world, a fact sheet says.

"During the last few years, over $1 billion has been invested in modernizing and improving the plant," BP said. "However, Texas City lacks strong integration into any BP marketing assets."

see **REFINERY SALE** page 11

PIPELINES & DOWNSTREAM

Exxon still waiting for right of way

Alaska officials don't plan to issue ExxonMobil a pipeline right of way for its Point Thomson development until after the U.S. Army Corps of Engineers decides on a wetlands permit for the project.

A spokesman for the Alaska pipeline coordinator's office said staff has been working diligently to draft a lease for the line, which would run 22 miles over state land along the Beaufort Sea coast to connect the Point Thomson field with the Badami pipeline to the west.

The coordinator's office expects to finish the draft lease by March and then share it with ExxonMobil, spokesman Graham Smith said.

But the coordinator's office, part of the Alaska Department of Natural Resources, won't issue a final, signed lease until after federal regulators act.

"Long story short, we're going to be waiting for the Corps on this one," Smith said.

The feeling is it would be more efficient to withhold the lease until after the Corps finishes its environmental impact statement and issues its record of decision on the Point Thomson development, Smith said.

But this could mean a considerable wait, as the Corps at last report was running about eight months behind on the EIS. The Corps said it expects to sign its record of decision on March 15, 2012.

PTE Pipeline LLC, a Houston-based affiliate of ExxonMobil Pipeline Co., applied for the state right of way in August 2010.

The pipeline, with a diameter of 12.75 inches, will carry natural gas condensate ExxonMobil intends to produce from the Point Thomson field, located some 60 miles

see **RIGHT OF WAY** page 11

● PIPELINES & DOWNSTREAM

RCA denies APE's request for waiver

Requires Armstrong, partners to submit two years of financial data in order to get CPCN; Enstar pegs early March startup date

By ERIC LIDJI
For Petroleum News

Alaska regulators have denied Anchor Point Energy's request to waive certain financial requirements as part of its efforts to operate a new pipeline in the southern Kenai Peninsula.

Anchor Point Energy, a subsidiary of Armstrong Oil and Gas and its four partners, recently applied for a certificate of public convenience and necessity to operate the new North Fork Pipeline. The pipeline runs 8 miles from the North Fork unit, north of Homer, to the city of Anchor Point, where it will connect into the Southcentral grid.

Normally, a company applying for the certificate must also provide two years of audited financial statements for all the companies with an ownership interest in the business.

Anchor Point asked for a waiver of that requirement.

Anchor Point tried to make the case that the North Fork Pipeline was a fairly risk free business and that the companies involved with running it were financially stable.

Application incomplete

For instance, Anchor Point noted that it didn't expect any "significant capital needs" once the pipeline went into operation and that its "revenues are virtually guaranteed" because Enstar Natural Gas is committed to buying North Fork gas under an approved long-term contract. In addition, Anchor Point said it has "no debt" and is "adequately insured."

The Regulatory Commission of Alaska issued a public notice about the waiver request in early January, and received no comments, but ultimately denied Anchor Point's request because the company

Anchor Point must file a new application by the end of February. Armstrong previously said it could bring North Fork online by mid-February, under good circumstances.

"failed to show good cause for waiver of the requirements."

Because the RCA denied the waiver, the entire certificate application became incomplete.

Now, Anchor Point will need to reapply. The company previously asked the RCA to allow it to operate the pipeline on a temporary basis in order to complete final tests.

Anchor Point must file a new application by the end of February. Armstrong previously said it could bring North Fork online by mid-February, under good circumstances.

Enstar aiming for March

Once complete, the North Fork Pipeline will connect to the South Peninsula Pipeline (previously known as the Anchor Point Pipeline). The Alaska Pipeline Co., a sister company of Enstar Natural Gas, is building that line. The SPP would in turn connect to the Kenai Kachemak Pipeline that feeds into the Southcentral regional transmission grid.

Enstar believes its new pipeline could be ready by early March.

The RCA is currently considering an interconnection agreement between the South Peninsula/Anchor Point Pipeline and the Marathon-operated Kenai Kachemak Pipeline. ●

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INTERNATIONAL

Exxon's Sakhalin-1 extended-reach record

Exxon Mobil Corp. said Jan. 28 that subsidiary Exxon Neftegas Ltd. has set a record for extended-reach drilling at the Odoptu field, offshore Sakhalin Island in the Russian Far East.

The Odoptu OP-11 well reached a total measured depth of 40,502 feet, 7.67 miles, to set a world record for extended-reach drilling, Exxon said. The well also set a world record with a horizontal reach of 37,648 feet, 7.13 miles.

Exxon said the well was completed in 60 days using ExxonMobil's fast drill process and integrated hole quality technology to maximize performance in every foot of hole drilled.

Odoptu, one of three Sakhalin-1 project fields, is five to seven miles offshore northeast of Sakhalin Island. The extended-reach drilling process enables drilling offshore beneath the seafloor from an onshore drilling site.

Six world records

ExxonMobil said that since the first Sakhalin-1 well was drilled in 2003, six of the world's 10 record-setting extended-reach wells have been drilled at the project. The specially designed Yastreb rig, used throughout, has set multiple industry records for measured depth, rate of penetration and directional drilling.

Since startup, Sakhalin-1 has produced some 300 million barrels of oil for export and has supplied approximately 235 billion cubic feet of associated natural gas to customers in Khabarovsk Krai, in far eastern Russia, for home heating and to meet growing energy needs.

Sakhalin-1 includes the Chayvo, Odoptu and Arkutun Dagi oil and gas fields off the northeast corner of Sakhalin Island. Potential recoverable resources include 2.3 billion barrels of oil and 17.1 trillion cubic feet of natural gas.

Exxon Neftegas operates the Sakhalin-1 project on behalf of a consortium that includes affiliates of the Russian state company Rosneft RN-Astra and Sakhalinmorneftegas-Shelf, the Japanese corporation Sodeco and the Indian state oil company ONGC Videsh Ltd.

—PETROLEUM NEWS

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RIGHT OF WAY

east of Prudhoe Bay.

The Point Thomson pipeline will cost about $80 million to build, with annual operating and maintenance costs of $12 million, the PTE application said.

ExxonMobil is anxious to secure regulatory clearance and get on with the development, as it has pledged publicly to begin production of 10,000 barrels a day of condensate by the end of 2014.

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

—WESLEY LOY

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REFINERY SALE

BP revealed its intent to sell the refineries on the same day it announced the resumption of quarterly dividend payments to shareholders, drawing the ire of some Gulf of Mexico residents who said they're still hurting economically from the Deepwater Horizon spill. BP said it would pay a dividend of 7 cents a share for the fourth quarter of 2010.

Chief Executive Bob Dudley called BP "a company in transition" as a result of the oil spill, and that 2011 will be a year of "recovery and consolidation."

"BP remains on track to meet its target of up to $30 billion of divestments by the end of 2011, having concluded agreements for divestments totaling around $22 billion by the end of 2010," a company press release said.

The release noted the divestment program has not included any of BP's inventory of future major upstream projects. ●

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● LAND & LEASING

Linc gets UCG exploration license

Alaska Mental Health Trust Land Office issues seven-year license over 181,414 acres; can later be converted to traditional leases

By ERIC LIDJI
For Petroleum News

The Alaska Mental Health Trust Land Office has issued Linc Energy an underground coal gasification exploration license over 181,414 acres of Southcentral and Interior Alaska.

The license is broken into three general areas, one on the east side of Cook Inlet near Nikiski, another on the west side of Cook Inlet near the Beluga Power Plant and a third in the Interior region of the state around Anderson, Healy and Nenana. The license covers almost all of the 190,000 acres the Mental Health Trust offered in June 2010.

Linc Energy is an Australian independent focused on underground coal gasification, a process for generating synthesis gas from deep coal deposits, as well as traditional oil and natural gas exploration. The company completed its first Alaska well in November.

That well targeted a conventional natural gas reservoir and encountered "a number of gas bearing horizons" and "a number of significant coal seams," the company said. Linc also hopes to soon drill at its acreage at Trading Bay, on the west side of the Cook Inlet basin.

However, that work represented only "stage one" of Linc's plans for Alaska, a way to generate revenue and experience that can be used toward underground coal gasification.

LINC ENERGY

"The gaining of this acreage marks Linc Energy's entry into stage two of its Alaska plan. In conjunction with our continuing oil and gas program, coal exploration for UCG will be conducted aggressively over the next 24 months," CEO Peter Bond said in a statement.

20 billion tons 'known'

Linc arrived in Alaska in March 2010, acquiring 123,000 acres near Point MacKenzie and Trading Bay from San Francisco-based independent GeoPetro Resources.

Prior to picking up the Mental Health

> *"In conjunction with our continuing oil and gas program, coal exploration for UCG will be conducted aggressively over the next 24 months."*
> **—Linc CEO Peter Bond**

Trust license, Linc estimated that its Alaska leases overlaid some 20 billion tons of "known" coal deposits. The company did not offer an estimate for the license area, other than to describe its coal potential as "extraordinary."

"Alaska is shaping up to be one of the key territories for Linc Energy to launch its global energy operations," Bond said. "It is a progressive jurisdiction and has significant infrastructure as an important energy hub."

Land managers use exploration licenses to generate activity in underexplored areas or for underdeveloped resources. Through a license, a company pays for the right to explore a broad area. If that work yields promising finds, the company can form traditional leases.

In its June offering, the Mental Health Trust proposed a seven-year license at $1 per acre. If the licensing leads to leasing, the Trust proposed to offer the land for an initial five-year term at $4 per acre per year that could be extended by five more years by production. ●

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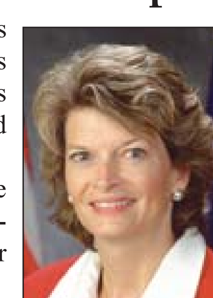
GOVERNMENT

Murkowski retains ranking member spot


SEN. LISA MURKOWSKI

U.S. Sen. Lisa Murkowski, R-Alaska, has retained her spot as ranking member of the Energy and Natural Resources Committee. Robert Dillon, a spokesman for the committee's Republican members, says Murkowski's spot was confirmed during a caucus vote Feb. 1.

Murkowski resigned her leadership post within the Republican conference when she announced plans to run a write-in campaign last year. She took the outsider route after losing her primary to Joe Miller.

Questions were raised about whether the caucus would strip her of her ranking position while she ran for re-election. But it decided to let her keep the spot.Since winning her race, she has expressed confidence that she'd keep her ranking title.

Republican committee members voted on the ranking spot. Their vote was voted on by the full caucus.

—THE ASSOCIATED PRESS

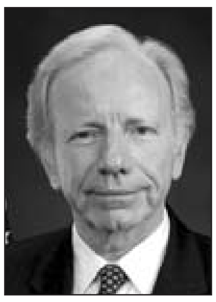
● ENVIRONMENT & SAFETY

Lieberman's last chance to close ANWR?

Connecticut senator again offers bill to designate coastal plain as wilderness; Alaska's Sen. Begich responds: 'Ain't gonna happen'

By WESLEY LOY
For Petroleum News

We've seen no shortage of calls in recent weeks to permanently block oil and gas exploration on the coastal plain of the Arctic National Wildlife Refuge.


SEN. JOE LIEBERMAN

The latest came Jan. 25 when U.S. Sen. Joe Lieberman, a Connecticut independent, introduced a bill, S. 33, to designate the coastal plain as wilderness.

Also known as the 1002 area, the coastal plain encompasses more than 1.5 million acres.

Nineteen of Lieberman's Senate colleagues, all Democrats with the exception of one other independent, signed on as co-sponsors of S. 33.

But Alaska's Democratic senator, Mark Begich, was not among them. He immediately panned the idea of closing off the coastal plain to oil and gas exploration and drilling.

"Ain't gonna happen," Begich said in a Jan. 25 press release.

'A dozen defeats'

Twelve times since 1989, Lieberman has either introduced or been a co-sponsor of legislation to protect the refuge.

Lieberman recently announced he won't run for re-election in 2012.

"I have long believed that we have a responsibility to future generations to preserve the Arctic National Wildlife Refuge, and I have fought to protect it for as long as I have been in the Senate," Lieberman said. "The fact is, we do not have to choose between conservation and exploration when it comes to our energy future; we can do both simultaneously while moving toward a sustainable and diverse national energy policy."

The press release from Begich's office predicted S. 33 will fail, marking "a dozen defeats for Lieberman's bill."

Regardless of party affiliation, Alaska lawmakers typically have supported ANWR oil and gas exploration. The coastal plain is seen as one of the last U.S. hopes for a multibillion-barrel oil strike, development of which would yield jobs and other economic benefits for the state.

Other conservation efforts

ANWR encompasses a total of 19.3 million acres in Alaska's northeast corner.

Oil and gas exploration and production already is prohibited on the coastal plain pending authorization from Congress. The big question now is whether this prohibition will be permanent.

The Alaska National Interest Lands Conservation Act of 1980 designated much of ANWR as wilderness, but Section 1002 of the act set aside the coastal plain for certain biological, seismic and geological studies. These studies are largely complete.

The U.S. Fish and Wildlife Service now oversees the 1002 area as a "minimal management" area — a status intended to maintain existing natural conditions — and likely will continue to do so "until Congress takes further action to decide the fate of the coastal plain," the agency's ANWR website says.

A congressional wilderness designation, or something akin to it, could foreclose any chance for drilling on the coastal plain.

The Fish and Wildlife Service is now conducting a review on whether to recommend new wilderness designations in ANWR, including the coastal plain.

U.S. Rep. Edward Markey, D-Mass., on Jan. 5 reintroduced his perennial legislation to designate the coastal plain as wilderness. The bill, H.R. 139, says such action "will still leave most of the North Slope of Alaska available for the development of energy resources, which will allow Alaska to continue to contribute significantly to meeting the energy needs of the United States without despoiling the unique Arctic coastal plain of the Arctic National Wildlife Refuge."

Using the refuge's 50th anniversary as a hook, environmental groups in November urged President Obama to designate ANWR as a national monument. Such a designation effectively could end chances for oil and gas activity on the coastal plain. ●

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WILCOX

geologic opportunities but of the small and mid-sized geological opportunities.

"And over the long term, that's what it's going to take to realize the sustainable prosperity and energy security in our state."

With locally focused companies a lot more oil and gas revenues will stay in the local area and be invested in energy or other sectors of the local economy, he said.

What's needed?

Cook Inlet production has dropped from 200,000 barrels per day to 10,000 bpd, but there's more oil and gas to be found, he said, and looking at mature basins elsewhere production declines and then rises again as new technologies allow more production or as the oil price rises.

Wilcox said Cook Inlet is the least developed, developed oil and gas basin in North America: the crude quality is high; it's next to the Pacific Rim and ready markets; there is a refinery optimized for Cook Inlet crude; there is a favorable fiscal regime — but there still isn't much going on.

That's because there are barriers to entry, including access issues and complex and unique systems for permits and taxes which make it difficult for small companies. Systems more similar to other basins in the Lower 48 and Canada are needed, he said.

Wilcox said the oil and gas system in Alaska evolved at a time when there were big companies and small government and is based on negotiation, but with small companies and a large government the situation is different.

"It's very easy even if the government isn't being aggressive to just bowl over the small guy. So you really need to … change that paradigm from a negotiation paradigm to a fostering business paradigm," he said.

"If you get enough of a critical mass of small companies in the local economic ecosystem — making money, sharing expertise … you start cutting down infrastructure costs because you're sharing things."

That sector can be grown by lowering barriers, creating "a clear and consistent regulatory regime" and easing up on some land restrictions. That will "broaden and diversify our oil and gas production opportunities" and result in "more stable and durable production for this state," Wilcox said. ●

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ENVIRONMENT & SAFETY

Alaska Forum on the Environment Feb. 7

The 13th annual Alaska Forum on the Environment begins Feb. 7 at the Dena'ina Convention Center in Anchorage.

AFE offers more than 80 break-out sessions with a range of topics that include: climate change, human overpopulation, green buildings, conservation and recovery for polar bears, community gardening in rural Alaska, landfill alternatives, invasive species in Alaska, mining issues, youth environmental summit, hydroelectric projects, North Slope methane hydrates and carbon dioxide exchange, shipping in arctic waters, environmental justice issues, and impacts of poor solid waste management on village health.

AFE runs Feb. 7-11. Detailed information on the keynotes and breakout sessions is available at the AFE website at: http://akforum.com.

—PETROLEUM NEWS

EXPLORATION & PRODUCTION

US drilling rig count up by 19 to 1,732

The number of rigs actively exploring for oil and natural gas in the U.S. increased by 19 the week ending Jan. 28 to 1,732.

Houston-based Baker Hughes Inc. reported that 913 rigs were exploring for gas and 809 for oil. Ten were listed as miscellaneous. A year ago, the count was 1,317.

Of the major oil- and gas-producing states, Pennsylvania gained 10 rigs, Louisiana gained five, New Mexico gained four, Alaska gained three, Colorado gained two and Wyoming gained one.

Arkansas and Oklahoma each lost two rigs and California, North Dakota and Texas each lost one. West Virginia was unchanged.

The rig count peaked at 4,530 in 1981, the height of the oil boom. The record low of 488 was in 1999.

—THE ASSOCIATED PRESS

GOVERNMENT

Begich pushes for Jones Act waiver

U.S. Sen. Mark Begich, D-Alaska, is asking the U.S. Department of Homeland Security to grant Escopeta Oil a waiver of the Jones Act in order to get a jack-up drilling rig to Cook Inlet.

Escopeta got a Jones Act waiver in 2006, on a previous attempt to bring a rig to Alaska.

As Escopeta once again prepares to bring a rig to Alaska, the company asked the federal government for an assurance that the 2006 waiver is still valid, but in November, the U.S. Customs and Border Protection called the waiver "neither open ended nor transferrable."

The Jones Act requires goods moving between U.S. ports to be carried on ships flagged and built in the U.S., but the heavy-lift vessel Escopeta plans to use to move its Spartan 151 jack-up from the Gulf of Mexico to Alaska is a foreign vessel.

Because that answer left the matter somewhat up in the air, Begich asked the Department of Homeland Security to issue the waiver now so Escopeta can bring the rig up this year.

The Jones Act requires goods moving between U.S. ports to be carried on ships flagged and built in the U.S., but the heavy-lift vessel Escopeta plans to use to move its Spartan 151 jack-up from the Gulf of Mexico to Alaska is a foreign vessel.

Without a waiver, Escopeta would be forced to pay a fine. Rowan, the last company to operate a jack-up rig in the Cook Inlet, chose to pay the fine rather than get the waiver.

Buccaneer Alaska, another company looking to bring a jack-up rig to Alaska this year, hopes to avoid the Jones Act by purchasing a rig currently cold stacked in Malaysia.

—ERIC LIDJI

continued from page 1

TRANSFER

final set of decisions will be made by northerners as to whether it's good enough to proceed."

Anne Marie Tout, president of the NWT Chamber of Commerce, said the milestone agreement gives the NWT the long-awaited and "rightful ability to manage and control public lands and to secure a share of revenues generated from those lands."

Dene boycott signing

Only two of the NWT's seven aboriginal groups — the Metis and Inuvialuit, who have negotiated land claims and self-government settlements in the oil and gas-rich northwest corner of the NWT — signed the deal. The rest including the Dene, whose land covers about 40 percent of the planned right of way of the MGP pipeline, boycotted.

Those five have appealed to Prime Minister Stephen Harper to overturn what they call a "secretive bilateral devolution negotiation."

However, Duncan said the pact will not infringe on the rights of aboriginal negotiators or groups, but he could not say whether the full participation of all seven groups is legally necessary.

"We think there will be full participation," he said. "The agreement is predicated on that occurring."

Roland said it will be at least two years before the legal text of a "devolution" agreement is in place, giving aboriginal leaders ample time to make their case.

"Now we've come to a place … where a final set of decisions will be made by northerners as to whether it's good enough to proceed," he said.

At stake is about 6 trillion cubic feet of discovered gas on the Mackenzie Delta, backing the proposed Mackenzie Gas Project, and an estimated additional 55 tcf in the Delta and Beaufort Sea, plus 6.2 billion barrels of onshore and offshore oil.

The NWT government has insisted all along that a transfer of federal powers is necessary to attract industry investment in resource development.

NWT production has peaked over the past decade at about 20,000 barrels per day of oil and 670 million cubic feet per day of gas from the southern NWT, but gas exploration has gone into decline pending Canadian government approval and corporate sanctioning of the 1.2 billion cubic feet per day MGP and an associated liquids pipeline.

Currently resource royalties from the NWT go directly to Ottawa, which funds most of the NWT's budget. The NWT has the highest per capita GDP of all provinces and territories at about C$90,000 for a population of 43,500.

If the transfer of power takes place, Ottawa will make a one-time payment of C$27 million in transition costs and C$65 million a year to cover the NWT's increased expenses.

Dene National Chief Bill Erasmus said "we're not against devolution, but our people want to be equal partners and they want to participate in developing the North in a positive way."

Dehcho Chief Sam Gargan said the current deal does not give the NWT a large enough share of resource royalties and does not protect the rights of Dene groups in their land-claim and self-government talks with Ottawa.

Of Canada's other two territories, the Yukon, with an estimated 900 million barrels of oil and 17 tcf of gas, signed a resource deal in 2003. Duncan said Ottawa is committed to starting negotiations with Nunavut, which, based on limited exploration, has an estimated 320 million barrels of oil and 16 tcf of gas. ●

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AGIA REPORT

million and has not reimbursed that amount; $2.5 million is being held pending receipt of additional information.

TC Alaska has submitted third-quarter 2010 reimbursement claims for gross expenditures of $22.3 million, claims which contain costs reimbursable at both the 50 percent and the 90 percent matching rates.

The next reimbursement is expected in late February.

Reimbursements by general cost categories include: $545,172 in general expenses (2 percent); $20,716,088 in pipeline related expenses (56 percent); $10,508,139 in gas treatment related expenses (29 percent); $1,619,235 in environmental, regulatory and land expenses (9 percent); and $3,345,903 in law and other third-party expenses (4 percent).

By region, 70 percent of the qualified expenditures were in Alaska, 24 percent in southern Yukon and 6 percent in British Columbia. ●

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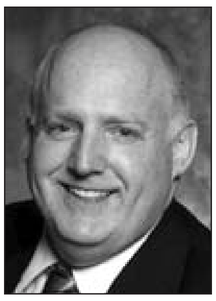
Petroleum news

Oil Patch Bits

Brice family to be inducted into JAA hall of fame

Calista Corp. said that the Brice family was inducted into the 25th annual Junior Achievement of Alaska's Business Hall of Fame Jan. 27 at the Dena'ina Civic & Convention Center in Anchorage. The Brice family, founders of Brice Inc. in 1961 in Fairbanks became a wholly owned subsidiary of Calista Corp. in July 2010.



SAM ROBERT BRICE

Brice Co. was awarded numerous contracts during construction of the trans-Alaska oil pipeline in the 1970s. In 2009 they were named Contractor of the Year by Alaska Business monthly and named Regional Small Business of the Year in 2001 by the U.S. Small Business Administration.

The Junior Achievement of Alaska honors leaders of Alaska businesses. Selection is made by peers based on commitment to Junior Achievement, direct and successful impact to Alaskan business, and a positive commitment to the Alaska business community.

"The Brice family is honored and humbled with this recognition," said Brice President Sam Robert Brice. "Our work doesn't just represent our companies, but also our family."

Global Diving & Salvage welcomes Juettner to AK

Global Diving & Salvage said Jan. 26 that it is pleased to announce the advancement of John Juettner to operations manager, Alaska Region. Juettner has been in the Alaska commercial diving industry for the past 17 years. He has been working in operational support and as a dive supervisor for the past 7 years. As operations manager, Juettner's responsibilities will include asset management, estimating, logistical support and project planning for the Alaska region. "The development of this new position in our region and more importantly, having John move into it will ensure that our customers receive the highest in customer service as well as the ability to utilize his background and knowledge in working in this challenging environment," said David DeVilbiss, Alaska regional manager, Global Diving & Salvage.

JOHN JUETTNER

Sullivan to participate in 2011 ExxonMobil Open

The Alaskan Sled Dog & Racing Association said Jan. 26 that on Feb. 12 Mayor of

see OIL PATCH BITS page 18

continued from page 1

SPURR GEOTHERMAL

sale and since then has moved ahead with a geothermal exploration program involving aerial surveys, ground surveying, surface sampling and the small-bore drilling.

To date the company has invested about $5 million in its Mount Spurr project, Thomsen said. The company has drilled two slim holes to depths of about 1,000 feet — the plan is to continue with the slim-hole drilling, with core holes to depths of up to 4,000 feet in 2011, and with the possibility of drilling a full-size production well in 2012, to determine whether there is a commercially viable geothermal reservoir, he said.

Customer needed

However, the project has reached a point where Ormat needs to find a potential customer, willing to sign up to a power purchase agreement that can underpin the risk of funding the Mount Spurr work.

"As a company, we're reaching the very tough decision of how much capital can we outlay without having a guaranteed contract to take that power, and at what price is that contract going to be at," Thomsen said.

The project should produce 50 to 100 megawatts of power, Thomsen said. And with an expected year-round reliability of 95 percent or better, and with a constant, self-refreshing underground heat source, a geothermal power plant could contribute to meeting the Railbelt's base-load power needs, he said.

Ormat typically self finances a geothermal project until the geothermal power plant goes into operation, at which point the company refinances the project using long term debt — the relatively low project risk at that stage leads to attractive interest rates on the debt.

In the case of Mount Spurr project, the company has been using a $2 million grant from the Alaska Energy Authority, with the company matching that grant with $2.1 million of its own money. The company has been recommended for a further $2 million AEA grant, subject to further company expenditure in excess of $3 million, Thomsen said.

Infrastructure cost

However, coupled into the financing issues for the project is the question of the likely $70 million to $80 million cost of the necessary power plant support infrastructure: a 40-mile power transmission line from Mount Spurr to the nearest point on the Railbelt power grid and about 25 miles of permanent access road. Ormat anticipates holding discussions with the state and with Chugach Electric Association, the operator of the Beluga power plant where a transmission line from Mount Spurr would connect with the grid, about the appropriate mechanism for infrastructure funding, whether by private industry or by the state.

With an estimated construction cost per kilowatt hour capacity of $5,000 to $6,000, the cost of a Mount Spurr power plant would be somewhat higher than the typical $3,000 to $5,000 per kilowatt hour of a comparable plant in the Lower 48. And the costs and possible performance of the plant lead to a likely electricity cost of around 12 cents to 13 cents per kilowatt hour, a figure that is a few cents higher than the avoided cost of using current sources of Railbelt power, Thomsen said.

A reduction in geothermal royalties enacted by the state legislature in 2010 has shaved about one cent off the projected power rate, but some additional incentive, perhaps a refundable tax credit, would be needed to allow geothermal to compete on a straight cost basis, he said.

Fixed cost

But although currently more expensive to produce than, say, power a from a natural gas-fueled plant, much of the cost of geothermal energy involves the amortization of the initial cost of the plant, thus offering the enticing prospect of locking in a fixed power price over a 20-year period, while also enabling the generation of base-load power with virtually no environmental impact. And a typical geothermal power purchase agreement conveys to the power utility all of the green attributes of the power source, such as the elimination of sulfur dioxide, carbon dioxide and nitrogen oxides emissions, Thomsen said.

The proposed design for a Mount Spurr power plant involves bring hot geothermal water to the surface through a well, using that water to heat a secondary, low-boiling point fluid and then using the boiling of that secondary fluid to drive a turbine. The used water would be re-injected underground into the geothermal reservoir, where geothermal energy would reheat the water for re-use. And the secondary fluid would also be continuously recycled.

Air cooling

Taking advantage of the low prevailing air temperatures on the flanks of Mount Spurr, the facility could be air cooled to prevent water evaporation, thus eliminating water depletion and thereby extending the life expectancy of the geothermal reservoir almost indefinitely into the future.

"Once we develop this project we have a lifetime supply of free fuel," Thomsen said.

And, so, the thorny question is whether the utilities, and hence the electricity ratepayers, are willing to pay a bit more now than the going electricity rate, to gain the geothermal benefits of locking in fixed future pricing and gaining the use an environmentally friendly power source.

Some states have renewable energy portfolio standards that drive energy economics in a direction that tends to make geothermal energy viable, Thomsen said. But Alaska, despite a state policy to increase renewable energy use, does not have a mandated standard to move the economic playing field. And so Ormat is facing this financial gap between current power prices and the potential cost of geothermal power.

"If the state wants to help us with that gap, we can offer the ratepayers a much lower price," Thomsen said. "If the state can't help us with that, we need to offer the ratepayers a higher price, and that could or could not make the project viable."

Multiple utilities

Thomsen also commented that having to deal with several interrelated Railbelt power utilities complicates power purchase agreement negotiations. In the Lower 48, there are typically one, or at most two, utilities involved, he said.

On the other hand, the Railbelt utilities and the local communities all endorse the Mount Spurr project, viewing Mount Spurr geothermal energy as a near-term means of addressing concerns over tightening natural gas supplies, he said.

With the use of proven geothermal technology, the Mount Spurr project presents little technical risk; the geology looks very encouraging; and the project permitting has progressed smoothly. The immediate project challenge is to secure a market for the geothermal power, Thomsen said.

—ALAN BAILEY

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continued from page 1

CINGSA

company had asked RCA for facility certification by Dec. 1 and tariff approval by the end of January in order to be able to proceed with facility construction and obtain project financing in a timely manner.

CINGSA is a joint venture between Semco Energy and MidAmerican Energy Holdings Co., while Semco is also the parent company of Enstar Natural Gas Co., the main Southcentral Alaska gas utility.

Significant challenge

Being the first gas storage that RCA has had to regulate, the tight time frame for the CINGSA project has presented some significant challenges to everyone involved in the regulatory process.

And during the RCA tariff hearing much discussion focused on the question of the cost of any gas losses from the facility, a cost traditionally passed through to gas consumers — it is impossible to completely eliminate any gas loss from a storage facility, so that relatively minor losses are generally viewed as part of the cost of doing business, along with the cost of gas used as fuel to power the facility's compressors.

The parties involved in the RCA hearing negotiated tariff language requiring RCA approval for the recovery of the costs of extraordinary gas losses and prohibiting the recovery of the cost of losses resulting from negligence. However, Commissioner Paul Lisankie disagrees with the approval of the gas-loss section of the tariff. CINGSA has not been sufficiently specific in stating what gas losses consumers would have to pay for, Lisankie wrote in a minority dissenting opinion.

Other tariff concerns included the specification of the costs that CINGSA would be able to recover from its gas storage fees, and the manner of reconciling the facility's initial fees, based in part on cost estimates, with subsequent fees adjusted to reflect actual costs.

CINGSA will charge fees to reserve storage capacity, to reserve withdrawal capacity and for actual gas injections and withdrawals.

Initial rates

Initial inception rates will be based on capital expenditures and the known cost of debt at the point of facility startup, plus estimates of the facility's other costs. After one complete year of facility operation, CINGSA will revise the rates using actual costs, including the actual costs of operation, with CINGSA absorbing any cost overrun during that first year. After five years of operation CINGSA will submit a complete, revised tariff to RCA for approval, using information gleaned from experience of operating the facility.

And, under an agreement associated with the tariff, Alaska Electric and Energy Cooperative, the wholesale power supplier to Homer Electric Association, has joined CINGSA's list of initial customers, with Enstar, Chugach Electric Association and Municipal Light & Power being the other customers.

In a separate order, also issued on Jan. 31, RCA approved the ability of Enstar, CINGSA's largest customer, to recover gas storage fees from gas consumers — there had been some concern that RCA might approve the gas storage facility but at a later date limit Enstar's ability to recover its gas storage costs.

However, the commission does require all CINGSA customers to file any firm storage agreements with the commission for review and approval.

Approval decision

In its order approving the facility tariff the commission provided a full explanation of its December decision to approve CINGSA's certificate — normally the commission would consider both the certificate and the tariff in a single hearing, but in the interests of early approval for the storage facility CINGSA had asked the commission to deal with the certificate first.

A key element in the approval decision was testimony by all parties involved in the RCA hearing that the Cook Inlet basin needs a gas storage facility of the type that CINGSA wants to build, and that CINGSA has the financial wherewithal and management ability to build and operate the facility.

As production from the aging Cook Inlet gas fields declines, a storage facility available for hire by third-party companies will enable utilities to warehouse summer gas to boost gas deliverability in the winter and to provide contingency gas supplies in the event of a gas-field equipment failure. The pumping of summer gas into the facility will also enable gas wells to continue operating year round, thus avoiding gas reservoir damage from well shut-ins in the summer and reducing the need for expensive gas supply contracts involving large gas delivery swings.

Gas to meet peak winter demand is becoming increasingly expensive, hearing witnesses testified. And, without new gas storage, peak gas deliverability will before long fall short of peak winter demand at any price, witnesses also said.

"We also find based upon the testimony of the Enstar, Chugach and ML&P witnesses that those utilities urgently need those (storage) services," the commission wrote in its Jan. 31 order. "We find based upon CINGSA's choice to develop the Cannery Loop reservoir, and the utilities' choice to sign binding contracts (precedent agreements) that obligate them to support CINGSA's Cannery Loop project … that CINGSA's Cannery Loop project is now the only facility that can meet the utilities' urgent needs."

Reservoir integrity

Vincent Goddard, president of Inlet Fish Producers of Kenai, whose business facilities sit over part of the proposed Sterling C storage reservoir, has raised questions over the physical integrity of the Cannery Loop reservoir. Goddard and his companies, collectively referred to as Inlet Entities, presented evidence to RCA, saying that an old gas well, the KU 13-8 well, in his property presents a significant risk of gas migration from the reservoir and that the well needs remediation.

However, the RCA commissioners say that they are relying on the Alaska Oil and Gas Conservation Commission's technical analysis of the storage reservoir and that CINGSA must comply with any AOGCC stipulations relating to the reservoir integrity — under Alaska statutes AOGCC regulates the safety and integrity of gas wells and gas storage reservoirs. In early December AOGCC approved gas injection into CINGSA's facility while requiring the remediation of three existing wells. AOGCC did not mandate remediation the KU 13-8 well but did require CINGSA to install gas detection equipment next to the wellhead.

On Dec. 14 the Inlet Entities asked AOGCC to reconsider the question of whether the KU 13-8 well should be remediated and AOGCC is reconsidering that aspect of its injection order.

Field monitoring

RCA said that it is concerned about the possible cost to gas consumers of gas losses, especially if the KU 13-8 is not remediated. But the commission cited a report commissioned by MidAmerican from consultancy firm Netherland, Sewell and Associates. The report said that there are risks associated with well remediation. Moreover, the report continued, routine field monitoring techniques could detect a gas leak through the well. And were a leak to be discovered, the well could subsequently be fixed.

Another issue relating to the viability of the CINGSA storage facility is the question of whether the Southcentral Alaska gas pipeline infrastructure will have the necessary capacity to handle the flow of gas to and from the facility. In testimony to RCA Enstar said that operation of the facility may require the installation of additional gas compressors on the Enstar gas transmission line from the Kenai Peninsula to Anchorage, with the conversion of the Cook Inlet Gas Gathering System under Cook Inlet to allow the flow of gas from the east side to the west side of the inlet perhaps providing another route for CINGSA gas.

Because CINGSA will not commence gas injection into its facility until April 2012, there is sufficient time for the companies involved in gas storage usage to figure out the required routing of the stored gas and then implement any necessary pipeline infrastructure upgrades, RCA said in its order.

"In our view, making these changes is not CINGSA's responsibility," the commission said.

In its final order, RCA rejected a request by Kenai Landing, a landowner in the area of the CINGSA facility, to intervene in the CINGSA hearing. Kenai Landing is concerned about CINGSA's right to requisition land for the facility, but the commission said that the petition to intervene had come too late in the regulatory procedure for acceptance. ●

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OIL PATCH BITS

Anchorage Dan Sullivan, along with several other municipal leaders, will convene at Tozier Track to participate in the inaugural "Top Dog" Charity Sled Dog Race. The event will be held as part of the ExxonMobil Open, which is one of the seasonal races organized by the Alaskan Sled Dog & Racing Association leading up to the Fur Rendezvous Open.

The participant with the fastest time will designate a $10,000 donation from ExxonMobil to the charity of their choice, along with bragging rights for the remainder of the year. Second place will designate a $4,000 donation; third place will designate $3,000; and the fourth and fifth places will designate $2,000 and $1,000, respectively.

The event is open to the public and activities start at 10 a.m.

For more information visit the organization's website at: www.asdra.org.

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

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BRPC

Kuparuk River unit.

BRPC estimates that the Brookian reservoir could contain some 35 million barrels of oil and that the Kuparuk reservoir could contain an additional 6 million barrels of oil.

Dedicated processing planned

If they make a commercial discovery, BRPC and its partners would likely build a dedicated micro-processing facility to bring their crude oil to sales quality, but the location of North Tarn near the Alpine pipeline greatly improves its economics.

"It's a common carrier pipeline and we're less than a mile away from it," Jim Winegarner, vice president of land and external affairs for BRPC, told Petroleum News on Jan. 28.

North Tarn doesn't need to be huge to be economic. "We think we could get there with a discovery in the Kuparuk at that 6 million barrels number," Winegarner said.

Although the Kuparuk is deeper and smaller than the Brookian, BRPC sees it as a better bet because of the compartmentalized geology of the Brookian, notorious for causing challenges across the North Slope from Tarn to Badami. "The Brookian formation would be a great upside to have, but that's a lot riskier prospect," Winegarner said.

Work under way

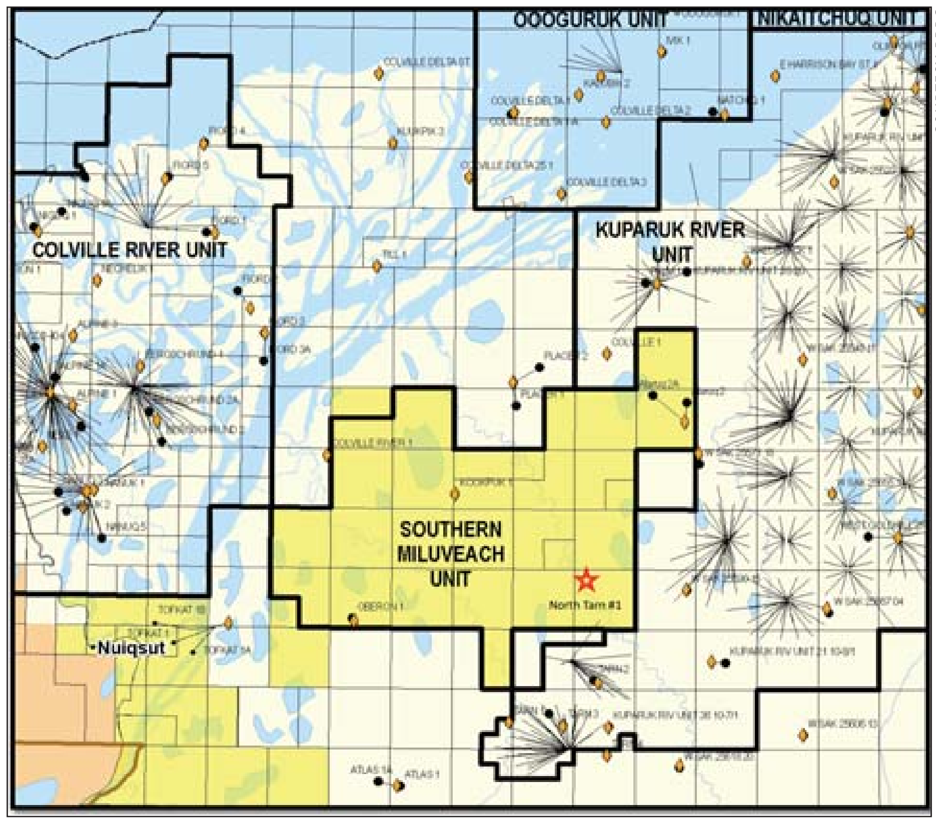
Work is already under way to build an ice pad at the drilling site and a four-mile ice road connecting the pad to drill site 2M within the Kuparuk River unit. The companies expect the well to take about 40 days to complete, from construction to the end of drilling.

The joint venture farmed-in six Eni Petroleum leases at North Tarn in January 2010 and recently applied to form the Southern Miluveach Unit, covering 56,460 acres over the leases. "This well that we're drilling is going to be the first work commitment that we're proposing in the Southern Miluveach unit," Winegarner said. "Overall, we have a four-well commitment that we're proposing for that unit, plus a seismic program."

The unit application is still pending with the Alaska Division of Oil and Gas.

BRPC operates a multi-company joint venture on behalf of TG World Energy and Ramshorn Investments. The group is responsible for some of the most active exploration campaigns on the North Slope in recent winters. The joint venture also owns the Tofkat prospect west of North Tarn, the Beechey Point unit in the Gwydyr Bay area north of the Prudhoe Bay unit and the Slugger prospect south of the Point Thomson unit.

BRPC is the operating arm of the Kansas-based Alaska Venture Capital Group.



COURTESY BRPC

Still eyeing other prospects

Over the past five years, BRPC and its partners have been among the most active exploration companies on the North Slope, and among the largest leaseholders as well.

In addition to North Tarn, the companies hold the Tofkat and Slugger prospects, and the Beechey Point unit, as well as many smaller exploration blocks across the North Slope.

Tofkat is less than 10 miles west of North Tarn, but Winegarner said that the distance between the prospects and the location of Tofkat along the Colville River mean the two prospects are not automatically candidates for joint development. However, because the leases at Tofkat start to expire next year, BRPC is considering applying for a unit soon.

Slugger is a prospect south of the Point Thomson unit where the joint venture wants to shoot a seismic program. Winegarner said BRPC would be looking for potential partners for that program at the upcoming North American Prospect Expo in Houston.

Since arriving in Alaska more than a decade ago, the various companies involved in the joint venture have spent most of their time and energies on what is now the Beechey Point unit. The unit is in the Gwydyr Bay region at the delta of the Kuparuk River.

The companies have conducted most of their existing exploration work on the west side of the Kuparuk delta and now want to explore several known oil accumulations on the east side of the delta, hopefully as soon as the winter of 2011 and 2012, Winegarner said.

JV likes tax revisions

The joint venturers are the only explorers on the North Slope this winter, but Winegarner believes more would be working if Gov. Sean Parnell's new oil tax passes into law.

"We could be drilling multiple wells this season instead of just one," he said.

In particular, Winegarner likes the provision that would extend a Cook Inlet tax credit on "well lease expenditures," or intangible drilling costs, to explorers on the North Slope.

The credit would cover drilling expenses that aren't for material objects, like surface facilities. "In an exploration well, that's a majority of our costs," Winegarner said. ●

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SHELL DECISION

800 jobs

The 2011 drilling program would have resulted in about 800 jobs in Alaska, while deferral of the program will further delay the prospect of bringing more oil into production, delaying the creation of thousands more jobs in the future, Slaiby said.

In October Shell applied to the Bureau of Ocean Energy Management, Regulation and Enforcement for an application to drill a single well in its Beaufort Sea Sivulliq prospect in 2011. BOEMRE is still processing that application together with a revised version of Shell's Beaufort Sea exploration plan — the agency has also been conducting a supplemental environmental assessment for Shell's plan.

"We're working very, very well with the BOEMRE," Slaiby said. "They're not only working on that (the supplemental environment assessment), they're working judiciously right now on our application for a permit to drill. So we're guardedly optimistic that we're going to see all this work fall into place with the BOEMRE."

But Shell also needs an EPA permit for air emissions from the Beaufort Sea drilling operation.

Litigation

In 2009, following litigation over a previous attempt to obtain air permits for Arctic outer continental shelf drilling, Shell applied for major permits rather than minor permits for its planned Chukchi Sea and Beaufort Sea drilling in the summer of 2010. But following issuance of these permits by EPA in April 2010, the Native Village of Point Hope and eight environmental organizations, including Resisting Environmental Destruction on Indigenous Lands (or REDOIL), appealed the permit approval to the Environmental Appeals Board, the panel of judges with final authority over EPA decisions.

On Dec. 30 the Environmental Appeals Board remanded Shell's Beaufort Sea permit back to EPA, finding fault with the EPA definition of a stationary emissions source and saying that the permit should have taken account of a new rule for the emissions of nitrogen oxides. The EAB rejected one of the other arguments against the permit but also said that it had not reached any view on several other claims in the appeal.

On Jan. 21 EPA filed a petition with the EAB, requesting some clarification of EAB's Dec. 30 ruling and asking the EAB to either rule on all claims in the appeal or to exclude the unresolved claims from the remand of the permit. EPA is concerned that the lack of resolution of all appeal claims will lead to continuing delays in the permitting process.

Slaiby said that as a result of the deferral of its Beaufort Sea drilling, Shell expects to farm out in 2011 most of the assets earmarked for the drilling operation.

"We maintain that the board's remand order erred in its treatment of the other issues addressed in this case and that, if left unaddressed, these errors will lead to further uncertainty, inefficiency and delay in resolving the Shell OCS-PSD Permits," EPA wrote in its petition.

And in the interests of dealing with the permit in an expedient manner, EPA also requested a ruling that any appeal over the revised permit should proceed direct to federal court, rather than go back to the EAB.

—ALAN BAILEY

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Begich, Murkowski, Young, Parnell slam feds

The members of Alaska's congressional delegation and Alaska's governor were united in condemning the federal government following Shell's Feb. 3 decision to cancel its plans to drill in the Beaufort Sea this summer because of the uncertainty of permitting.

All released statements critical of the Obama Administration and the U.S. Environmental Protection Agency.

"I put the blame for this squarely on the EPA and the Obama Administration who have taken virtually every opportunity to block responsible development of Alaska's resources," said Sen. Mark Begich, a Democrat.

"The actions taken by this administration will result in all of us paying more for gasoline — not to mention the loss of jobs and revenue that responsible development bring," said Sen. Lisa Murkowski, a Republican.

Congressman Don Young, a Republican, said: "We are making it near impossible for companies to do business in the U.S.; where's the incentive? It is absurd and foolish and completely indicative of an Administration that has no interest in responsible resource development or a thriving economy."

Alaska Gov. Sean Parnell, a Republican, speaking at a press availability, called it "just another example of the federal government dragging its feet, killing jobs and making us even more reliant on oil from the Middle East and elsewhere, where as we can see from the situation in Egypt it's very unstable."

Begich said he has "talked to EPA Administrator Lisa Jackson multiple times, and will continue to make the case for Shell to be able to move forward with exploration." He said Shell hopes to get the air permits it needs for 2012, and said he would continue to work with the company and EPA to make that happen.

"It is shameful to see another season lost," Begich said.

Murkowski, the ranking member of the Senate Energy and Natural Resources Committee, said, "The EPA's refusal, or simple inability, to issue key permits in a timely fashion is indefensible," and called on the administration to review EPA's handling of Shell's permit applications.

She said the inability of the federal government "to process a straightforward air permit calls into question its willingness to support a rational energy policy."

Young said "any attempt at project development is shut down by the EPA," called the administration's talk about jobs just lip service and said the country is being crippled. "They won't be happy until we've run all business out of the country and we're back to traveling on dirt roads in covered wagons."

"It's unfathomable that a company … can buy federal leases but can't get onto them," Parnell said. "It's also unfathomable that they cannot get an air permit after five years of time that they can get in the Gulf of Mexico in a matter months."

—KRISTEN NELSON

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